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	$ 4,099,808
3	Storage	$ 13,900,648
4	Peaking	$ 2,286,161
5	Total Gross Demand Cost	$ 20,286,617
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,923,632
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 20,286,617
9	Capacity Assignment as % of Total Gross Demand Cost	14.41%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 590,849
14	Storage	$ 2,003,310
15	Peaking	$ 329,473
16	Total Capacity Assignment Credit	$ 2,923,632
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,508,959
21	Storage	$ 11,897,338
22	Peaking	$ 1,956,688
23	Total Net Demand Cost (Less Capacity Assignment)	$ 17,362,985
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	18,356
28	Less 14.41% NH Transp. Capacity Assignment	(2,645)
29	Net Pipeline MDQ	15,711
30		
31	Net Pipeline MDQ	15,711
32	Less: Firm Sales Base Use	3,028
33	Remaining Pipeline MDQ	12,683
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$223.35
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,508,959
40	Less: Base Pipeline Use	$ 676,314
41	Remaining Pipeline Use	$ 2,832,644

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	2014-2015 Winter Period Filing, 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 C**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 14.41% 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	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147
47	Rank	5	3	1	2	4	6
48	% Max Month	47.80%	76.32%	100.00%	82.66%	59.51%	29.82%
49	PR	3.60%	5.61%	17.34%	3.17%	2.93%	2.45%
50	CumPR	8.00%	16.54%	37.04%	19.71%	10.93%	4.41%

51

52	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
53	Remaining Load for Peak Months Only	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147
54	Rank	5	3	1	2	4	6
55	% Max Month	47.80%	76.32%	100.00%	82.66%	59.51%	29.82%
56	PR	3.60%	5.61%	17.34%	3.17%	2.93%	4.97%
57	CumPR	8.57%	17.10%	37.60%	20.27%	11.49%	4.97%

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	8.00%	16.54%	37.04%	19.71%	10.93%	4.41%
63	Storage & Peaking	8.00%	16.54%	37.04%	19.71%	10.93%	4.41%
64	Capacity Release	8.57%	17.10%	37.60%	20.27%	11.49%	4.97%
65	Interr. Margins & Off Sys Sales	8.57%	17.10%	37.60%	20.27%	11.49%	4.97%

66

67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
69	Pipeline - Base	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 56,360
70	Pipeline - Remaining	$ 226,703	$ 468,415	$ 1,049,271	$ 558,209	$ 309,634	$ 124,831
71	Total Pipeline	$ 283,062	$ 524,774	$ 1,105,631	$ 614,569	$ 365,993	$ 181,190
72							
73	Storage & Peaking	$ 1,108,768	$ 2,290,944	$ 5,131,824	$ 2,730,114	$ 1,514,370	$ 610,528
74							
75	Less Credits to Demand Cost						
76	Cap Rel Margins, Asset Mgt Credit, TGP Refund & PNGTS Litigation Expense	$ 406,168	$ 810,793	$ 1,783,147	$ 961,109	$ 544,994	$ 235,634
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
79							
80	Total Direct Demand Costs	$ 985,663	$ 2,004,925	$ 4,454,308	$ 2,383,574	$ 1,335,369	$ 556,084
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

45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
46	Remaining Load for All Months	582,716	105,033	0	18,192	139,110	1,022,278	28,639,269	26,771,941	1,867,328
47	Rank	8	10	12	11	9	7			
48	% Max Month	8.62%	1.55%	0.00%	0.27%	2.06%	15.13%			
49	PR	0.82%	0.13%	0.00%	0.02%	0.06%	0.93%	37.04%		
50	CumPR	1.03%	0.15%	0.00%	0.02%	0.21%	1.96%	100.00%	96.63%	3.37%

51

52	**Peak Months Only**	**Annual**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only	26,771,941	26,771,941	
54	Rank			
55	% Max Month			
56	PR	37.60%		
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	1.03%	0.15%	0.00%	0.02%	0.21%	1.96%	100.00%	96.63%	3.37%
63	Storage & Peaking	1.03%	0.15%	0.00%	0.02%	0.21%	1.96%	100.00%	96.63%	3.37%
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	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 676,314	$ 338,157	$ 338,157	50.00%	50.00%
70	Pipeline - Remaining	$ 29,160	$ 4,333	$ -	$ 693	$ 5,920	$ 55,477	$ 2,832,644	$ 2,737,062	$ 95,582	96.63%	3.37%
71	Total Pipeline	$ 85,519	$ 60,692	$ 56,360	$ 57,053	$ 62,279	$ 111,837	$ 3,508,959	$ 3,075,219	$ 433,739	87.64%	12.36%
72												
73	Storage & Peaking	$ 142,615	$ 21,191	$ -	$ 3,390	$ 28,952	$ 271,331	$ 13,854,026	$ 13,386,549	$ 467,478	96.63%	3.37%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins, Asset Mgt Credit, TGP Refund & PNGTS Litigation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$4,741,845	$ 4,741,845	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 228,134	$ 81,883	$ 56,360	$ 60,443	$ 91,231	$ 383,168	$ 12,621,140	$ 11,719,923	$ 901,217	92.86%	7.14%

81

82	Indirect Demand Costs/(Credits)					
83	Miscellaneous Overhead	$ 512,686	$ 416,811	$ 95,875	81.30%	18.70%
84	Local Production & Storage	$ 420,658	$ 420,658	$ -	100.00%	0.00%
85	Subtotal	$ 933,344	$ 837,469	$ 95,875	89.73%	10.27%

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, TGP Refund & PNGTS Litigation Expense	Schedule 1A, Page 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	($5,330,574)	($658,933)	($4,671,641)	Schedule 21, Line 89	Schedule 5B, Page 5*	A - B
2	Capacity Release Revenues	($70,204)	$0	($70,204)	Schedule 21, Line 88		A - B
3	PNGTS Refund	$0	$0	$0			A - B
4	Total NH Cap Rel and Asset Management	($5,400,778)	($658,933)	($4,741,845)			Sum (LN1 + LN 2 + LN 5)

*: Provided in the 2014-2015 Winter Period Filing

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	1,511,393	1,003,305	909,965	946,078	1,037,510	1,951,012	32,209,152	7,359,263
2	New Hampshire Sales Storage	0	0	0	0	0	0	6,953,982	0
3	New Hampshire Sales Peaking	10,247	10,317	10,692	10,975	10,189	10,251	995,375	62,671
4	Total New Hampshire Firm Sales Sendout	1,521,640	1,013,623	920,657	957,052	1,047,699	1,961,262	40,158,509	7,421,934
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	1,521,640	1,013,623	920,657	957,052	1,047,699	1,961,262	40,158,509	7,421,934
9	Total Firm Sales	1,511,370	1,006,619	914,279	950,425	1,040,489	1,948,123	39,417,643	7,371,305
10	Difference (LAUF & Company Use)	10,270	7,004	6,377	6,627	7,211	13,139	740,865	50,629
11	Percent Difference	0.67%	0.69%	0.69%	0.69%	0.69%	0.67%	1.84%	0.68%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 380,316	$ 235,148	$ 215,961	$ 218,870	$ 240,132	$ 538,673	$ 22,309,990	$ 1,829,100
15	New Hampshire Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,935	$ -
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,075,461	$ -
17	New Hampshire Total Peaking	$ 13,975	$ 13,803	$ 13,959	$ 13,978	$ 12,650	$ 12,496	$ 1,960,396	$ 80,863
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,483	$ -
19	Total New Hampshire Sales Variable Costs	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,380,265	$ 1,909,963
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,352,330	$ 1,909,963
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,380,265	$ 1,909,963
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.2516	$ 0.2344	$ 0.2373	$ 0.2313	$ 0.2314	$ 0.2761	$ 0.6927	$ 0.2485
27	New Hampshire Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0009	$ -
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4423	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 1.3638	$ 1.3379	$ 1.3056	$ 1.2736	$ 1.2416	$ 1.2191	$ 1.9695	$ 1.2903
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0008	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.2591	$ 0.2456	$ 0.2497	$ 0.2433	$ 0.2413	$ 0.2810	$ 0.6818	$ 0.2573
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	938,709	908,429	920,518	938,709	908,429	938,709	11,034,355	5,553,503
37	Base Commodity Cost Excld Hedging	$ 236,210	$ 212,911	$ 218,466	$ 217,165	$ 210,256	$ 259,177	$ 5,744,887	$ 1,354,185
38	Base Hedging Commodity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,818	$ -
39	Remaining Commodity Excld Hedging	$ 158,081	$ 36,040	$ 11,455	$ 15,683	$ 42,526	$ 291,993	$ 21,607,443	$ 555,778
40	Remaining Hedging Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,117	$ -
41	Total Commodity Excld Hedging	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,352,330	$ 1,909,963
42	Total Hedging	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,935	$ -
43	Total Commodity (Incl Hedging)	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,380,265	$ 1,909,963

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 22, LN 10 * LN 59 * 10
2	New Hampshire Sales Storage	Schedule 22, LN 3 * LN 59 * 10
3	New Hampshire Sales Peaking	Schedule 22, LN 4 * LN 59 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Schedule 22, LN 8 * 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 73
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 74
16	New Hampshire Total Storage	Schedule 22, LN 75
17	New Hampshire Total Peaking	Schedule 22, LN 76
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 79
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 41
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

REDACTED

Estimated Delivered City-Gate Commodity Costs and Volumes
May 2015 through October 2015

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	[redacted]	448,841	[redacted]
Tennessee Production	[redacted]	934,796	[redacted]
Niagara	[redacted]	129,408	[redacted]
Chicago	[redacted]	424	[redacted]
Maritimes Delivered	[redacted]	7,351	[redacted]
PNGTS Receipts	[redacted]	2,045	[redacted]
LNG	[redacted]	12,880	[redacted]
Total Delivered Commodity Cost	$3,956,495	1,535,746	$2.576

Schedules 3

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

			Winter						Summer						
	Sales Revenues								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Total
2	Residential Heat & Non Heat								678,440	451,862	410,412	426,637	467,066	874,495	3,308,911
3	Sales HLF Classes								313,239	208,627	189,489	196,980	215,647	403,758	1,527,740
4	Sales LLF Classes								519,691	346,130	314,379	326,808	357,776	669,870	2,534,654
5	Total								1,511,370	1,006,619	914,279	950,425	1,040,489	1,948,123	7,371,305
6	Rates														
7	Residential Heat & Non Heat CGA								$0.3333	$0.3333	$0.3333	$0.3333	$0.3333	$0.3333	
8	Sales HLF Classes CGA								$0.2739	$0.2739	$0.2739	$0.2739	$0.2739	$0.2739	
9	Sales LLF Classes CGA								$0.3690	$0.3690	$0.3690	$0.3690	$0.3690	$0.3690	
10	Revenues														
11	Residential Heat & Non Heat								$ (226,124)	$ (150,606)	$ (136,790)	$ (142,198)	$ (155,673)	$ (291,469)	$ (1,102,860)
12	Sales HLF Classes								$ (85,796)	$ (57,143)	$ (51,901)	$ (53,953)	$ (59,066)	$ (110,589)	$ (418,448)
13	Sales LLF Classes								$ (191,766)	$ (127,722)	$ (116,006)	$ (120,592)	$ (132,019)	$ (247,182)	$ (935,287)
14	Total Sales								$ (503,686)	$ (335,470)	$ (304,697)	$ (316,743)	$ (346,758)	$ (649,241)	$ (2,456,595)
15															
16			Winter						Summer						
17	**Gas Costs and Credits**								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18		Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 72,290	$ 72,290	$ 72,290	$ 72,290	$ 72,290	$ 72,290	$ 433,739
21	Storage								$ 66,896	$ 66,896	$ 66,896	$ 66,896	$ 66,896	$ 66,896	$ 401,377
22	Peaking								$ 11,017	$ 11,017	$ 11,017	$ 11,017	$ 11,017	$ 11,017	$ 66,101
23	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 150,203	$ 150,203	$ 150,203	$ 150,203	$ 150,203	$ 150,203	$ 901,217
24	NUI Commodity Costs														
25	NUI Total Pipeline Volumes								320,053	204,212	184,685	187,064	213,838	413,014	1,522,866
26	Pipeline Costs Modeled in Sendout™								$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 3,790,308
27	NYMEX Price Used for Forecast								$ 2.9160	$ 2.9510	$ 3.0010	$ 3.0090	$ 2.9960	$ 3.0200	
28	NYMEX Price Used for Update								$ 2.9160	$ 2.9510	$ 3.0010	$ 3.0090	$ 2.9960	$ 3.0200	
29	Increase/(Decrease) NYMEX Price														
30	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
31	Updated Pipeline Costs								$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	
32	Interruptible Volumes - NH								0	0	0	0	0	0	
33	Average Supply Cost ($/MMBtu)								$ 2.52	$ 2.34	$ 2.37	$ 2.31	$ 2.31	$ 2.76	
34	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Updated Pipeline Costs								$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	
36	New Hampshire Allocated Percentage								47.22%	49.13%	49.27%	50.58%	48.52%	47.24%	
37	NH Updated Pipeline Costs								$ 380,316	$ 235,148	$ 215,961	$ 218,870	$ 240,132	$ 538,673	$ 1,829,100
38	NYMEX Options Contracts														
39															
40	Number of Contracts								0	0	0	0	0	0	
41	Option Contract Price								$ -	$ -	$ -	$ -	$ -	$ -	
42	Hedging Expenses								$ -	$ -	$ -	$ -	$ -	$ -	
43	NYMEX Option Strike Price								-	-	-	-	-	-	
44	NYMEX Price Used for Forecast								$ 2.9160	$ 2.9510	$ 3.0010	$ 3.0090	$ 2.9960	$ 3.0200	
48	New Hampshire Allocated Percentage								47.22%	49.13%	49.27%	50.58%	48.52%	47.24%	
49	NH Futures Hedging (Gain)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	NH Commodity Costs														
51	Pipeline Excl Hedging								$ 380,316	$ 235,148	$ 215,961	$ 218,870	$ 240,132	$ 538,673	$ 1,829,100
52	Hedging (Gain)/Loss Estimate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Peaking								$ 13,975	$ 13,803	$ 13,959	$ 13,978	$ 12,650	$ 12,496	$ 80,863
55	Total Commodity Costs								$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 1,909,963

Northern Utilities

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

56	Inventory Finance Charge														$ -
57	Asset Management and Capacity Release														
58	NUI AMA Revenue														$ -
59	PNGTS Litigation Cost														$ -
60	NUI Capacity Release														$ -
61	NUI AMA Rev & Cap. Release Subtotal														$ -
62	NH AMA Revenue														$ -
63	NH Capacity Release														$ -
64	NH Total Asset Management and Capacity Release		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65															
66	**Total Anticipated Direct Cost of Gas**		$ -	$ -	$ -	$ -	$ -	$ -	$ 544,495	$ 399,154	$ 380,123	$ 383,051	$ 402,985	$ 701,373	$ 2,811,180
67			Winter						Summer						
68									(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
69		Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
70	Working Capital														
71	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 544,495	$ 399,154	$ 380,123	$ 383,051	$ 402,985	$ 701,373	$ 2,811,180
72	Working Capital Percentage		0.0824%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
73	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -	$ -	$ 448	$ 329	$ 313	$ 315	$ 332	$ 578	$ 2,315
74	Beginning Period Working Capital Balance		$ (387)	$ (388)	$ (389)	$ (390)	$ (391)	$ (392)	$ (393)	$ 55	$ 384	$ 699	$ 1,016	$ 1,352	
75	End of Period Working Capital Allowance		$ (387)	$ (388)	$ (389)	$ (390)	$ (391)	$ (392)	$ 55	$ 384	$ 697	$ 1,014	$ 1,348	$ 1,929	
76	Interest		$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (0)	$ 1	$ 1	$ 2	$ 3	$ 4	$ 5
77	End of period with Interest	$ (387)	$ (388)	$ (389)	$ (390)	$ (391)	$ (392)	$ (393)	$ 55	$ 384	$ 699	$ 1,016	$ 1,352	$ 1,934	
78	Bad Debt														
79	Projected Bad Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,889	$ 4,889	$ 4,889	$ 4,889	$ 4,889	$ 4,889	$ 29,333
80	Beginning Period Bad Debt Balance		$ 921	$ 923	$ 926	$ 928	$ 931	$ 933	$ 936	$ 5,834	$ 10,745	$ 15,669	$ 20,607	$ 25,558	
81	End of Period Bad Debt Balance		***$ 921***	***$ 923***	***$ 926***	***$ 928***	***$ 931***	***$ 933***	***$ 5,825***	***$ 10,723***	***$ 15,634***	***$ 20,558***	***$ 25,496***	***$ 30,447***	
82	Interest		$ 2	$ 3	$ 3	$ 3	$ 3	$ 3	$ 9	$ 22	$ 36	$ 49	$ 62	$ 76	$ 270
83	End of Period Bad Debt Balance with Interest	$ 921	$ 923	$ 926	$ 928	$ 931	$ 933	$ 936	$ 5,834	$ 10,745	$ 15,669	$ 20,607	$ 25,558	$ 30,523	
84	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Miscellaneous Overhead								$ 15,979	$ 15,979	$ 15,979	$ 15,979	$ 15,979	$ 15,979	$ 95,875
89	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
90	Beginning Balance Over/Under Collection		$ (470,799)	$ (473,260)	$ (475,200)	$ (476,454)	$ (477,744)	$ (479,038)	$ (480,335)	$ (424,772)	$ (346,152)	$ (255,560)	$ (173,854)	$ (102,021)	$ (4,635,188)
91	Net Costs - Revenues		$ (1,184)	$ (658)	$ 33	$ -	$ -	$ -	$ 56,788	$ 79,663	$ 91,405	$ 82,287	$ 72,206	$ 68,111	$ 448,652
92	Ending Balance before Interest		$ (471,983)	$ (473,917)	$ (475,167)	$ (476,454)	$ (477,744)	$ (479,038)	$ (423,548)	$ (345,109)	$ (254,746)	$ (173,273)	$ (101,648)	$ (33,909)	$ (4,186,537)
93	Average Balance		$ (471,391)	$ (473,589)	$ (475,183)	$ (476,454)	$ (477,744)	$ (479,038)	$ (451,942)	$ (384,940)	$ (300,449)	$ (214,416)	$ (137,751)	$ (67,965)	$ (4,410,863)
94	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%	
95	Interest Expense		$ (1,277)	$ (1,283)	$ (1,287)	$ (1,290)	$ (1,294)	$ (1,297)	$ (1,224)	$ (1,043)	$ (814)	$ (581)	$ (373)	$ (184)	$ (11,946)
96	Ending Balance Incl Interest Expense	$ (470,799)	$ (473,260)	$ (475,200)	$ (476,454)	$ (477,744)	$ (479,038)	$ (480,335)	$ (424,772)	$ (346,152)	$ (255,560)	$ (173,854)	$ (102,021)	$ (34,094)	
97	**Total Over/Under Collection Ending Balance**	$ (470,265)	$ (472,725)	$ (474,663)	$ (475,916)	$ (477,205)	$ (478,497)	$ (479,793)	$ (418,883)	$ (335,023)	$ (239,192)	$ (152,230)	$ (75,111)	$ (1,637)	
98															
99	**Total Indirect Cost of Gas**	$ (470,265)	$ (1,275)	$ (1,281)	$ (1,286)	$ (1,289)	$ (1,292)	$ (1,296)	$ 20,101	$ 20,177	$ 20,404	$ 20,654	$ 20,892	$ 21,342	$ (354,413)
100															
101	**Total Cost of Gas**	$ (470,265)	$ (1,275)	$ (1,281)	$ (1,286)	$ (1,289)	$ (1,292)	$ (1,296)	$ 564,596	$ 419,331	$ 400,528	$ 403,705	$ 423,877	$ 722,715	$ 2,456,767
102															
103	**Total Interest**	$ -	$ (1,275)	$ (1,281)	$ (1,286)	$ (1,289)	$ (1,292)	$ (1,296)	$ (1,215)	$ (1,020)	$ (777)	$ (529)	$ (307)	$ (104)	$ (11,671)

Schedules 4

Northern Utilities, Inc.
New Hampshire Division
Schedule 4
Page 1 of 1

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2014**					
2						
3	Total		$	573,318		Company Analysis
4	Distribution		$	257,587		Company Analysis
5	Distribution (%)			44.93%		
6	Non-Distribution		$	315,731		Company Analysis
7	Non-Distribution(%)			55.07%		LN 6 / LN 3
8						
9	Non-Distribution		$	315,731		LN 6
10	Peak Period		$	291,707		Company Analysis
11	Peak Period (%)			92.39%		LN 10/ LN 9
12	Summer Period		$	24,024		LN 9 - LN 10
13	Summer Period (%)			7.61%		LN 12 / LN 9
14						
15	**Forecast Bad Debt Expense 12 Months Ended July 31, 2015**					
16						
17	Annual Total		$	700,000		Company Forecast
18	Annual Non-Distribution		$	385,495		LN 17* LN 7
19	Winter Non-Distribution		$	356,163		LN 18* LN 11
20	Summer Non-Distribution		**$**	**29,333**		LN 18* LN 13

Schedule 5A & Attachment

Table 4 - Estimated Gas Supply Demand Costs
November 1, 2014 through October 31, 2015

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,898,754	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 25,879,093	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	$ 1,490,461	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 3,271,550	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,345,672)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 31,231,031	Sum Lines 1 through 6.

Northern Utilities, Inc.

Pipeline Contract Demand Cost Estimates

November 1, 2014 through October 31, 2015

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 NUI-FXW-10	$ 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 NUI-FXW-10	$ 8,223	$ 98,680
Granite	14-001-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.8633	12	Line 3 of Page 2, Att NUI-FXW-10	$ 386,330	$ 4,635,960
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	Line 4 of Page 2, Att NUI-FXW-10	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 29.5496	12	Line 5 of Page 2, Att NUI-FXW-10	$ 32,505	$ 390,055
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 65.6280	5	Line 6 of Page 2, Att NUI-FXW-10	$ 2,165,724	$ 10,828,620
Tennessee	5083	FT-A	No	4,605	Zone 0	Zone 6	$ 23.9133	12	Line 7 of Page 2, Att NUI-FXW-10	$ 110,121	$ 1,321,449
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 21.2245	12	Line 8 of Page 2, Att NUI-FXW-10	$ 181,469	$ 2,177,634
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 8.3778	12	Line 9 of Page 2, Att NUI-FXW-10	$ 22,226	$ 266,716
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att NUI-FXW-10	$ 10,343	$ 124,110
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att NUI-FXW-10	$ 16,374	$ 196,493
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att NUI-FXW-10	$ 6,834	$ 82,005
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att NUI-FXW-10	$ 31,388	$ 376,657
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.4980	12	Line 11 of Page 2, Att NUI-FXW-10	$ 5,306	$ 63,667
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 18.9336	2	Line 12 of Page 2, Att NUI-FXW-10	$ 643,742	$ 1,287,485
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 29.0954	10	Line 12 of Page 2, Att NUI-FXW-10	$ 989,244	$ 9,892,436
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 9.3777	2	Line 13 of Page 2, Att NUI-FXW-10	$ 55,675	$ 111,351
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 14.5540	10	Line 13 of Page 2, Att NUI-FXW-10	$ 86,407	$ 864,071
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.3084	12	Line 14 of Page 2, Att NUI-FXW-10	$ 13,857	$ 166,288
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 15 of Page 2, Att NUI-FXW-10	$ 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 NUI-FXW-10	$ 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 NUI-FXW-10	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.4480	12	Line 18 of Page 2, Att NUI-FXW-10	$ 2,719	$ 32,632

Total Annual Demand Costs	$ 36,268,308

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	14-001-FT-NN	100,000	32,321	35,529	32,150	32%	36%	32%	$ 4,635,960	$ 1,498,389	$ 1,647,110	$ 1,490,461
Iroquois	R181001	6,569	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	1,100			100%	0%	0%	$ 390,055	$ 390,055	$ -	$ -
PNGTS	1997-004	33,000		33,000		0%	100%	0%	$ 10,828,620	$ -	$ 10,828,620	$ -
Tennessee	5083	4,605	4,605			100%	0%	0%	$ 1,321,449	$ 1,321,449	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,177,634	$ 2,177,634	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 266,716	$ -	$ 266,716	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 124,110	$ 124,110	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 196,493	$ 196,493	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 82,005	$ 82,005	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 376,657	$ 376,657	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 63,667	$ 63,667	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 1,287,485	$ -	$ 1,287,485	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 9,892,436	$ -	$ 9,892,436	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 111,351	$ 111,351	$ -	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 864,071	$ 864,071	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 166,288	$ 166,288	$ -	$ -
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%	$ 32,632	$ 32,632	$ -	$ -
Annual Total Demand Costs									$ 36,268,308	$ 8,898,754	$ 25,879,093	$ 1,490,461

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2014 through October 31, 2015

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Support for Demand Rates	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0211	$ 1.5400	12	Line 1 of Page 3, Att to Sch 5A	$ 65,664	$ 78,411	$ 144,075
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	Line 2 of Page 3, Att to Sch 5A	$ 497	$ 687	$ 1,184
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5480	12	Line 2 of Page 3, Att to Sch 5A	$ 189	$ 1,398	$ 1,587
W-10	01052	Storage	Yes	3,400,000		34,000			12	Line 3 of Page 3, Att to Sch 5A	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges $ 3,036,846

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.
Peaking Contract Demand Cost Estimates
November 1, 2014 through October 31, 2015

Resource	Supplier	Contract Quantity	Maximum Daily Quantity	Months Per Year	Monthly Fixed Charges	Annual Fixed Charges
LNG Contract	[redacted]	75,000	2,000	5		[redacted]
Peaking Contract 1	[redacted]	300,000	20,000	5		[redacted]
Peaking Contract 2	[redacted]	300,000	20,000	5		[redacted]
Total Peaking Supply Contract Demand Costs						$ 3,271,550

Northern Utilities, Inc.
Asset Management and Capacity Release Revenue Projections
November 1, 2014 through October 31, 2015

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	$ (11,198,056)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (63,667)
Tennessee 5265	$ (83,950)
Total Capacity Release	$ (147,616)

Total Asset Management and Capacity Release Revenue	$ (11,345,672)

REDACTED

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for March 4, 2015

		Estimated Adders to NYMEX Last Day Settlement											
Line	Supply Source	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
2	Chicago	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Iroquois Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	PNGTS Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	PNGTS Baseload	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Maritimes Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Niagara	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Tennessee Production (Zone 0)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Tennessee Production (Zone L)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Tennessee Production (Zone 4)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Tenessee Zone 4 Spot	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Peaking Supply 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Peaking Supply 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	W10 Supply (Injection)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	TGP FS Supply (Injection)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	W10 AMA Spot Tier I	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	W10 AMA Spot Tier II	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	W10 AMA Spot	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	AGT Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21													
22	NYMEX Forecast							$2.806	$2.845	$2.896	$2.913	$2.903	$2.929

Northern Utilities, Inc.
Transportation Contract Rates
November 2014 through October 2015

Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
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	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633
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	$ 25.9843	$ 25.9843	$ 25.9843	$ 25.9843	$ 25.9843	$ 25.9843	$ 25.9843	$ 25.9843	$ 25.9843
6	PNGTS	FT (Seasonal)	N/A	N/A		Page 17	$ 76.4666	$ 76.4666	$ 76.4666	$ 49.3701	$ 49.3701							
7	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560
11	Texas Eastern	FT-1/FTS	M3	M3	1	Pages 23, 24	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980
12	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 18.9336	$ 18.9336	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954
13	TransCanada	FT	Parkway	Iroquois		Page 26	$ 9.3777	$ 9.3777	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540
14	Union	M12	Dawn	Parkway		Page 26	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084
15	Vector	FT-1	Alliance	Dawn		Page 39	$ 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 40	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625							
17	Vector	FT-1	Alliance	St. Clair	2	Pages 36, 37	$ 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	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
19	Algonquin	AFT-1 (AFT-2)	N/A	N/A	3	Page 5, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
20	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	3	Page 5, 46	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124
21	Granite	FT-NN	N/A	N/A	3	Page 7, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
22	Iroquois	RTS-1	Zone 1	Zone 1	3	Pages 9, 46	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042
23	LNG Trucking		Everett, MA	LNG Plant		Page 13	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100
24	PNGTS	FT	N/A	N/A	3	Page 17, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
25	Tennessee	FT-A	Zone 0	Zone 4	3, 4	Page 20, 21, 46	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926
26	Tennessee	FT-A	Zone 0	Zone 6	3, 4	Page 20, 21, 46	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359
27	Tennessee	FT-A	Zone L	Zone 4	3, 4	Page 20, 21, 46	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488
28	Tennessee	FT-A	Zone L	Zone 6	3, 4	Page 20, 21, 46	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927
29	Tennessee	FT-A	Zone 4	Zone 6	3, 4	Page 20, 21, 46	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140
30	Tennessee	FT-A	Zone 5	Zone 6	3, 4	Page 20, 21, 46	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861
31	TransCanada	FT	Dawn	E. Hereford		Page 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	TransCanada	FT	Parkway	Iroquois		Page 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Union	M12	Dawn	Parkway		Page 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Vector	FT-1	Alliance	W-10		Page 37, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
35	Vector	FT-1	Alliance	Dawn		Page 37, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
36	Vector	FT-1	W-10 Storage	Dawn		Page 37, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Fuel Rate Support	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
37	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 6	0.81%	0.91%	0.91%	0.91%	0.91%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
38	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 6	0.81%	0.91%	0.91%	0.91%	0.91%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
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	5	Page 12	0.40%	0.40%	0.40%	0.40%	0.40%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%
41	PNGTS	FT	N/A	N/A	5	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	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
43	Tennessee	FT-A	Zone 0	Zone 6		Page 21	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%
44	Tennessee	FT-A	Zone L	Zone 4		Page 21	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
45	Tennessee	FT-A	Zone L	Zone 6		Page 21	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
46	Tennessee	FT-A	Zone 4	Zone 6		Page 21	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
47	Tennessee	FT-A	Zone 5	Zone 6		Page 21	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
48	TransCanada	FT	Dawn	E. Hereford	5	Page 38	2.15%	2.15%	2.15%	2.15%	2.15%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
49	TransCanada	FT	Parkway	Iroquois	5	Page 38	1.10%	1.10%	1.10%	1.10%	1.10%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
50	Union	M12	Dawn	Parkway		Page 35	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	5	Page 42	0.88%	0.88%	0.88%	0.88%	0.88%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
52	Vector	FT-1	Alliance	Dawn	5	Page 42	0.88%	0.88%	0.88%	0.88%	0.88%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
53	Vector	FT-1	W-10 Storage	Dawn	5	Page 42	0.33%	0.33%	0.33%	0.33%	0.33%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%

Note 1 FT-1 Demand Rate = $4.838 plus FT-1 / FTS Rate = $0.66, totals to $5.498.
Note 2 Negotiated Rate Agreement = $8.0908 per Dth (Page 36), which is higher than Maximum Reservation Rate (Page 37), so Maximum Reservation Rate prevails.
Note 3 Variable Rate includes ACA Charge on Page 46.
Note 4 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 5 Fuel Rates Estimated based on 12 months historic data.

Northern Utilities, Inc.
Underground Storage Contract Rates
November 2014 through October 2015

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	1.07%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.3400				
3	W-10	Storage	1	Pages 43, 44, 45			$ -	0.40%	$ -	0.90%

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

Schedules 6A and 6B

REDACTED

Northern Utilities, Inc.
Commodity Cost by Supply Source
May 2015 through October 2015

Description	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Season
Pipeline Supplies							
Tenn Zone 4 Spot	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chicago	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Algonquin Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TGP Zone 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Niagara	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Iroquois Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PNGTS Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PNGTS Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maritimes Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Pipeline	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 3,790,308
Company Managed Pipeline	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Pipeline	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 3,790,308
Underground Storage							
Tennessee Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Company Managed Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supplies							
Peaking Contract 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Peaking Contract 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Peaking	$ 29,595	$ 28,095	$ 28,331	$ 27,638	$ 26,073	$ 26,454	$ 166,186
Company Managed Peaking	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Peaking	$ 29,595	$ 28,095	$ 28,331	$ 27,638	$ 26,073	$ 26,454	$ 166,186
Total NUI Commodity	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 3,956,495
Company-Managed (NH & ME)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Service (NH & ME)	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 3,956,495
Sales Service Commodity	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 3,956,495
Off-System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Sales Service	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 3,956,495

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
May 2015 through October 2015

Description	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Season
Pipeline Supplies							
Tenn Zone 4 Spot	75,620	73,181	75,620	75,620	73,181	75,620	448,841
Tennessee Production	192,729	127,659	109,065	111,444	132,103	261,797	934,796
Chicago	0	0	0	0	0	424	424
Algonquin Receipts	0	0	0	0	0	0	0
TGP Zone 6	0	0	0	0	0	0	0
Niagara	51,704	3,373	0	0	8,554	65,777	129,408
Iroquois Receipts	0	0	0	0	0	0	0
PNGTS Receipts	0	0	0	0	0	2,045	2,045
PNGTS Delivered	0	0	0	0	0	0	0
Maritimes Delivered	0	0	0	0	0	7,351	7,351
Total Pipeline	320,053	204,212	184,685	187,064	213,838	413,014	1,522,866
Company Managed Pipeline	0	0	0	0	0	0	0
Net Pipeline	320,053	204,212	184,685	187,064	213,838	413,014	1,522,866
Underground Storage							
Tennessee Storage	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
Total Storage	0	0	0	0	0	0	0
Company Managed Storage	0	0	0	0	0	0	0
Net Storage	0	0	0	0	0	0	0
Peaking Supplies							
Peaking Contract 1	0	0	0	0	0	0	0
Peaking Contract 2	0	0	0	0	0	0	0
LNG	2,170	2,100	2,170	2,170	2,100	2,170	12,880
Total Peaking	2,170	2,100	2,170	2,170	2,100	2,170	12,880
Company Managed Peaking	0	0	0	0	0	0	0
Net Peaking	2,170	2,100	2,170	2,170	2,100	2,170	12,880
Total NUI Commodity	322,223	206,312	186,855	189,234	215,938	415,184	1,535,746
Company-Managed (NH & ME)	0	0	0	0	0	0	0
Sales Service (NH & ME)	322,223	206,312	186,855	189,234	215,938	415,184	1,535,746
Sales Service Commodity	322,223	206,312	186,855	189,234	215,938	415,184	1,535,746
Off-System Sales	0	0	0	0	0	0	0
Net Sales Service	322,223	206,312	186,855	189,234	215,938	415,184	1,535,746

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Northern Utilities, Inc.
Maine Division
Attachment NUI-FXW-6
Page 3 of 3

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
May 2015 through October 2015

Description	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Season
Pipeline Supplies							
Tenn Zone 4 Spot	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chicago	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Algonquin Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TGP Zone 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Niagara	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Iroquois Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PNGTS Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PNGTS Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maritimes Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Pipeline	$ 2.516	$ 2.344	$ 2.373	$ 2.313	$ 2.314	$ 2.761	$ 2.489
Company Managed Pipeline							
Net Pipeline	$ 2.516	$ 2.344	$ 2.373	$ 2.313	$ 2.314	$ 2.761	$ 2.489
Underground Storage							
Tennessee Storage							
Washington 10 Storage							
Total Storage							
Company Managed Storage							
Net Storage							
Peaking Supplies							
Peaking Contract 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Peaking Contract 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Peaking	$ 13.638	$ 13.379	$ 13.056	$ 12.736	$ 12.416	$ 12.191	$ 12.903
Company Managed Peaking							
Net Peaking	$ 13.638	$ 13.379	$ 13.056	$ 12.736	$ 12.416	$ 12.191	$ 12.903
Total NUI Commodity	$ 2.591	$ 2.456	$ 2.497	$ 2.433	$ 2.413	$ 2.810	$ 2.576
Company-Managed (NH & ME)							
Sales Service (NH & ME)	$ 2.591	$ 2.456	$ 2.497	$ 2.433	$ 2.413	$ 2.810	$ 2.576
Sales Service Commodity	$ 2.591	$ 2.456	$ 2.497	$ 2.433	$ 2.413	$ 2.810	$ 2.576
Off-System Sales							
Net Sales Service	$ 2.591	$ 2.456	$ 2.497	$ 2.433	$ 2.413	$ 2.810	$ 2.576

REDACTED

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B
Page 1 of 19

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

Line	City Gate Delivered Costs	Reference	2015 Summer May-15	2015 Summer Jun-15	2015 Summer Jul-15	2015 Summer Aug-15	2015 Summer Sep-15	2015 Summer Oct-15	2015 Summer
1	Purchased Volumes	Line 9	76,955	74,473	76,955	76,955	74,473	76,955	456,767
2	City Gate Delivered Volume	Line 37	75,620	73,181	75,620	75,620	73,181	75,620	448,841
3	Total Purchase Cost	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 773,795
4	Variable Transportation Costs	Sum Lines 29 and 39	$ 8,742	$ 8,460	$ 8,742	$ 8,742	$ 8,460	$ 8,742	$ 51,886
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 825,682
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1.840
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	76,955	74,473	76,955	76,955	74,473	76,955	456,767
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.882
11	NYMEX Cost	Line 9 times Line 10	$ 215,937	$ 211,875	$ 222,863	$ 224,171	$ 216,195	$ 225,402	$ 1,316,442
12	NYMEX Basis Price	Att to Sch 5A, Line 11 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ (1.188)
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ (542,647)
14	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1.694
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 773,795
16									
17	Transportation Fuel Losses and Variable Charges								
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	Total Contract Recevied Volume	Sendout Optimization	76,955	74,473	76,955	76,955	74,473	76,955	456,767
23	Received Volume	Line 14						76,955	456,767
24	Percentage Allocated	Line 23 divided by Line 22	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
25	Received Volume	Line 9	76,955	74,473	76,955	76,955	74,473	76,955	456,767
26	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
27	Delivered Volume	Line 25 times (1 - Line 26)	75,886	73,438	75,886	75,886	73,438	75,886	450,418
28	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140
29	Variable Transportation Costs	Line 27 times Line 28	$ 8,651	$ 8,372	$ 8,651	$ 8,651	$ 8,372	$ 8,651	$ 51,348
30									
31	Transportation Segment 3								
32	Granite State Gas Transmission (Contract 10-010-FT-NN)								
33	Receipt Point: Pleasant St.								
34	Delivery Point: Northern City Gates								
35	Received Volume	Line 27	75,886	73,438	75,886	75,886	73,438	75,886	450,418
36	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%
37	City Gate Delivered Volume	Line 35 times (1 - Line 36)	75,620	73,181	75,620	75,620	73,181	75,620	448,841
38	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
39	Variable Transportation Costs	Line 37 times Line 38	$ 91	$ 88	$ 91	$ 91	$ 88	$ 91	$ 539

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
2	City Gate Volumes - Z0	Line 2 of Page 5	-	-	-	-	-	-	-
3	City Gate Volumes - Z1	Line 2 of Page 6	42,830	-	-	-	498	109,983	153,312
4	City Gate Volumes - Z4	Line 2 of Page 7	149,899	127,659	109,065	111,444	131,605	151,813	781,485
5	Total City Gate Volumes	Sum Lines 1 through 3	192,729	127,659	109,065	111,444	132,103	261,797	934,796
6	City Gate Delivered Costs - Z0	Line 6 of Page 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	City Gate Delivered Costs - Z1	Line 6 of Page 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	City Gate Delivered Costs - Z4	Line 5 of Page 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Total City Gate Delivered Costs	Sum Lines 5 through 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Average Delivered Price	Line 8 divided by Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 9	152,546	129,913	110,991	113,412	133,929	154,494	795,284
2	City Gate Delivered Volume	Line 34	`	127,659	109,065	111,444	131,605	151,813	781,485
3	Total Purchase Cost	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,940,826
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 17,328	$ 14,757	$ 12,608	$ 12,883	$ 15,214	$ 17,550	$ 90,340
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2,031,166
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.599
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	152,546	129,913	110,991	113,412	133,929	154,494	795,284
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.880
11	NYMEX Cost	Line 9 times Line 10	$ 428,043	$ 369,602	$ 321,429	$ 330,369	$ 388,795	$ 452,513	$ 2,290,751
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ (0.440)
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ (349,925)
14	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.440
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,940,826
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	152,546	129,913	110,991	113,412	133,929	154,494	795,284
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
24	Delivered Volume	Line 22 times (1 - Line 23)	150,425	128,107	109,448	111,835	132,067	152,346	784,229
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140
26	Variable Transportation Costs	Line 24 times Line 25	$ 17,148	$ 14,604	$ 12,477	$ 12,749	$ 15,056	$ 17,367	$ 89,402
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	150,425	128,107	109,448	111,835	132,067	152,346	784,229
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)	149,899	127,659	109,065	111,444	131,605	151,813	781,485
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
36	Variable Transportation Costs	Line 34 times Line 35	$ 180	$ 153	$ 131	$ 134	$ 158	$ 182	$ 938

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 23	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 35	-	-	-	-	-	-	-
3	Total Purchase Price	Line 15							
4	Total Purchase Cost	Line 2 times Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 27 and 37	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 6 divided by Line 2							
8									
9	<u>Tennessee Zone 0 Supply Costs</u>								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
11	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1							
14	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Purchase Price	Line 10 plus Line 12							
16	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 1A								
20	Tennessee Gas Pipeline (Contract 5083)								
21	Receipt Point: Tennessee Zone 0								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 10	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 5A, Line 43 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 5A, Line 26 of Page 2							
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28									
29	Transportation Segment 2A								
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	-	-	-	-	-	-	-
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%	
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 23	44,799	-	-	-	521	115,040	160,361
2	City Gate Delivered Volume	Line 35	42,830	-	-	-	498	109,983	153,312
3	Total Purchase Price	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.834
4	Total Purchase Cost	Line 2 times Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 454,394
5	Variable Transportation Costs	Sum Lines 27 and 37	$ 12,632	$ -	$ -	$ -	$ 147	$ 32,437	$ 45,216
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 499,610
7	Average Delivered Price	Line 6 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.259
8									
9	<u>Tennessee Zone L Supply Costs</u>								
10	Purchased Volumes	Sendout Optimization	44,799	-	-	-	521	115,040	160,361
11	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.895
12	NYMEX Cost	Line 9 times Line 10	$ 125,707	$ -	$ -	$ -	$ 1,513	$ 336,953	$ 464,173
13	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ (0.061)
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ (9,778)
15	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.834
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 454,394
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 1B								
20	Tennessee Gas Pipeline (Contract 5083)								
21	Receipt Point: Tennessee Zone L								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 10	44,799	-	-	-	521	115,040	160,361
24	Fuel Loss Rate	Att to Sch 5A, Line 45 of Page 2	4.06%				4.06%	4.06%	4.06%
25	Delivered Volume	Line 23 times (1 - Line 24)	42,980	-	-	-	500	110,370	153,850
26	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2	$ 0.2927				$ 0.2927	$ 0.2927	$ 0.2927
27	Variable Transportation Costs	Line 25 times Line 26	$ 12,580	$ -	$ -	$ -	$ 146	$ 32,305	$ 45,032
28									
29	Transportation Segment 2B								
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	42,980	-	-	-	500	110,370	153,850
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)	42,830	-	-	-	498	109,983	153,312
36	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
37	Variable Transportation Costs	Line 35 times Line 36	$ 51	$ -	$ -	$ -	$ 1	$ 132	$ 184

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
2	Purchased Volumes	Line 9	-	-	-	-	-	440	440
3	City Gate Delivered Volume	Sum Lines 68, 88 and 108	-	-	-	-	-	424	424
4	Total Purchase Cost	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,288
5	Variable Transportation Costs	Sum Lines 27, 47, 60, 70, 80, 90, 100 anc	$ -	$ -	$ -	$ -	$ -	$ 39	$ 39
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,327
7	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.125
8									
9	Chicago Supply Costs								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	440	440
11	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.929
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 1,288	$ 1,288
13	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
15	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.929
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,288
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1&2								
20	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
21	Receipt Point: Alliance								
22	Delivery Point: Dawn (Interconnects with Union)								
23	Received Volume	Line 10	-	-	-	-	-	440	440
24	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2						1.20%	1.20%
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	434	434
26	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2						$ 0.0012	$ 0.0012
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1
28									
29	Transportation Segment 3								
30	Union Pipeline (Contract M12205)								
31	Receipt Point: Dawn								
32	Delivery Point: Parkway (Interconnects with TransCanada)								
33	Received Volume	Line 25	-	-	-	-	-	434	434
34	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2						0.53%	0.53%
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	432	432
36	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2						$ -	$ -
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Transportation Segment 4								
40	TransCanada Pipeline (Contract 41235)								
41	Receipt Point: Parkway								
42	Delivery Point: Iroquois								
43	Received Volume	Line 35	-	-	-	-	-	432	432
44	Fuel Loss Rate	Att to Sch 5A, Line 49 of Page 2						0.53%	0.53%
45	Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	-	-	430	430
46	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2						$ -	$ -
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48									
49	Transportation Segment 5								
50	Iroquois Pipeline (Contract R181001)								
51	Receipt Point: Waddington								
52	Delivery Point: Wright (Interconnection with Tennessee)								
53	Total Contract Recevied Volume	Sendout Optimization	-	-	-	-	-	430	430
54	Received Volume	Line 45	-	-	-	-	-	430	430
55	Percentage Allocated	Line 54 divided by Line 53	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100%
56	Received Volume	Line 45	-	-	-	-	-	430	430
57	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2						0.19%	0.19%
58	Delivered Volume	Line 56 times (1 - Line 57)	-	-	-	-	-	429	429
59	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2						$ 0.0042	$ 0.0042
60	Variable Transportation Costs	Line 58 times Line 59	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2
61									
62	Transporation Segment 6A								
63	Tennessee Gas Pipeline (Contract 95196)								
64	Receipt Point: Wright								
65	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
66	Received Volume	Line 58	-	-	-	-	-	429	429
67	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2						1.05%	1.05%
68	City Gate Delivered Volume	Line 66 times (1 - Line 67)	-	-	-	-	-	424	424
69	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2						$ 0.0861	$ 0.0861
70	Variable Transportation Costs	Line 68 times Line 69	$ -	$ -	$ -	$ -	$ -	$ 37	$ 37
71									
72	Transportation Segment 6B								
73	Tennessee Gas Pipeline (Contract 95196)								
74	Receipt Point: Wright								
75	Delivery Point: Pleasant St. (Interconnection with Granite)								
76	Received Volume	Line 68	-	-	-	-	-	-	-
77	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
78	Delivered Volume	Line 76 times (1 - Line 77)	-	-	-	-	-	-	-
79	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
80	Variable Transportation Costs	Line 78 times Line 79	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81									
82	Transportation Segment 7B								
83	Granite State Gas Transmission (Contract 10-010-FT-NN)								
84	Receipt Point: Pleasant St.								
85	Delivery Point: Northern City Gates								
86	Received Volume	Line 78	-	-	-	-	-	-	-
87	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
88	City Gate Delivered Volume	Line 86 times (1 - Line 87)	-	-	-	-	-	-	-
89	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
90	Variable Transportation Costs	Line 88 times Line 89	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91									
92	Transportation Segment 6C								
93	Tennessee Gas Pipeline (Contract 41099)								
94	Receipt Point: Wright								
95	Delivery Point: Mendon (Interconnection with Algonquin)								
96	Received Volume	Line 58	-	-	-	-	-	-	-
97	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
98	Delivered Volume	Line 96 times (1 - Line 97)	-	-	-	-	-	-	-
99	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
100	Variable Transportation Costs	Line 98 times Line 99	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101									
102	Transportation Segment 7C								
103	Algonquin Gas Transmission (Contract 93200F)								
104	Receipt Point: Mendon								
105	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
106	Received Volume	Line 98	-	-	-	-	-	-	-
107	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2							
108	City Gate Delivered Volume	Line 106 times (1 - Line 107)	-	-	-	-	-	-	-
109	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2							
110	Variable Transportation Costs	Line 108 times Line 109	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Sum Lines 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 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>Algonquin Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 20 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	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	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 38 of Page 2							1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 20 of Page 2							
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
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	Tennessee Zone 6 Supply								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 19 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 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	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
2	Purchased Volumes	Line 9	52,437	3,420	-	-	8,675	66,708	131,240
3	City Gate Delivered Volume	Line 45	51,704	3,373	-	-	8,554	65,777	129,408
4	Total Purchase Cost	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 389,448
5	Variable Transportation Costs	Sum Lines 27, 37 and 47	$ 4,529	$ 295	$ -	$ -	$ 749	$ 5,762	$ 11,336
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 400,784
7	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.097
8									
9	Niagara Supply Costs								
10	Purchased Volumes	Sendout Optimization	52,437	3,420	-	-	8,675	66,708	131,240
11	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.876
12	NYMEX Cost	Line 9 times Line 10	$ 147,137	$ 9,731	$ -	$ -	$ 25,184	$ 195,389	$ 377,441
13	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 0.091
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 12,007
15	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.967
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 389,448
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1A								
20	Tennessee Gas Pipeline (Contract 5292)								
21	Receipt Point: Niagara								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 9	30,581	3,420	-	-	6,828	40,168	80,998
24	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%			1.05%	1.05%	1.05%
25	Delivered Volume	Line 23 times (1 - Line 24)	30,260	3,384	-	-	6,757	39,746	80,148
26	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861			$ 0.0861	$ 0.0861	$ 0.0861
27	Variable Transportation Costs	Line 25 times Line 26	$ 2,605	$ 291	$ -	$ -	$ 582	$ 3,422	$ 6,901
28									
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 39375)								
31	Receipt Point: Niagara								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 9	21,855	-	-	-	1,847	26,540	50,242
34	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%				1.05%	1.05%	1.05%
35	Delivered Volume	Line 33 times (1 - Line 34)	21,626	-	-	-	1,827	26,262	49,715
36	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861				$ 0.0861	$ 0.0861	$ 0.0861
37	Variable Transportation Costs	Line 35 times Line 36	$ 1,862	$ -	$ -	$ -	$ 157	$ 2,261	$ 4,280
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 10-010-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	51,886	3,384	-	-	8,584	66,008	129,862
44	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%
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	51,704	3,373	-	-	8,554	65,777	129,408
46	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
47	Variable Transportation Costs	Line 45 times Line 46	$ 62	$ 4	$ -	$ -	$ 10	$ 79	$ 155

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	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
2	Purchased Volumes	Line 9	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 38	-	-	-	-	-	-	-
4	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 30, 40, 50, 60, 70 and 80	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 5 divided by Line 2							
8									
9	<u>Irqoquois Receipts Supply Costs</u>								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
11	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1							
14	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Purchase Price	Line 10 plus Line 12							
16	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 5								
20	Iroquois Pipeline (Contract R181001)								
21	Receipt Point: Waddington								
22	Delivery Point: Wright (Interconnection with Tennessee)								
23	Total Contract Recevied Volume	Sendout Optimization	-	-	-	-	-	430	430
24	Received Volume	Line 10	-	-	-	-	-	-	-
25	Percentage Allocated	Line 24 divided by Line 23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
26	Received Volume	Line 15	-	-	-	-	-	-	-
27	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2							
28	Delivered Volume	Line 26 times (1 - Line 27)	-	-	-	-	-	-	-
29	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2							
30	Variable Transportation Costs	Line 28 times Line 29	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31									
32	Transporation Segment 6A								
33	Tennessee Gas Pipeline (Contract 95196)								
34	Receipt Point: Wright								
35	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
36	Received Volume	Line 28	-	-	-	-	-	-	-
37	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	-	-	-	-	-	-	-
39	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
40	Variable Transportation Costs	Line 38 times Line 39	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41									
42	Transportation Segment 6B								
43	Tennessee Gas Pipeline (Contract 95196)								
44	Receipt Point: Wright								
45	Delivery Point: Pleasant St. (Interconnection with Granite)								
46	Received Volume	Line 38	-	-	-	-	-	-	-
47	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
48	Delivered Volume	Line 46 times (1 - Line 47)	-	-	-	-	-	-	-
49	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
50	Variable Transportation Costs	Line 48 times Line 49	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51									
52	Transportation Segment 7B								
53	Granite State Gas Transmission (Contract 10-010-FT-NN)								
54	Receipt Point: Pleasant St.								
55	Delivery Point: Northern City Gates								
56	Received Volume	Line 48	-	-	-	-	-	-	-
57	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
58	City Gate Delivered Volume	Line 56 times (1 - Line 57)	-	-	-	-	-	-	-
59	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
60	Variable Transportation Costs	Line 58 times Line 59	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61									
62	Transportation Segment 6C								
63	Tennessee Gas Pipeline (Contract 41099)								
64	Receipt Point: Wright								
65	Delivery Point: Mendon (Interconnection with Algonquin)								
66	Received Volume	Line 28	-	-	-	-	-	-	-
67	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
68	Delivered Volume	Line 66 times (1 - Line 67)	-	-	-	-	-	-	-
69	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
70	Variable Transportation Costs	Line 68 times Line 69	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71									
72	Transportation Segment 7C								
73	Algonquin Gas Transmission (Contract 93200F)								
74	Receipt Point: Mendon								
75	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
76	Received Volume	Line 68	-	-	-	-	-	-	-
77	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2							
78	City Gate Delivered Volume	Line 76 times (1 - Line 77)	-	-	-	-	-	-	-
79	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2							
80	Variable Transportation Costs	Line 78 times Line 79	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B
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Source of Supply: PNGTS (Pittsburg, NH)
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 9	-	-	-	-	-	2,052	2,052
2	City Gate Delivered Volume	Line 34	-	-	-	-	-	2,045	2,045
3	Total Purchase Cost	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,261
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ 5	$ 5
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,266
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.554
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	2,052	2,052
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.929
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 6,010	$ 6,010
12	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 0.610
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,252
14	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.539
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,261
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	-	-	-	-	-	2,052	2,052
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2						0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	2,052	2,052
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2						$ 0.0012	$ 0.0012
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2
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	-	-	-	-	-	2,052	2,052
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)	-	-	-	-	-	2,045	2,045
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2

REDACTED

Source of Supply: Maritimes Baseload Supply
City-Gate Delivered Supply

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 9	-	-	-	-	-	7,351	7,351
2	City Gate Delivered Volume	Line 1	-	-	-	-	-	7,351	7,351
3	Total Purchase Cost	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 24,473
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 24,473
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.329
7									
8	Maritimes Supply Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	7,351	7,351
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.929
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 21,532	$ 21,532
12	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 0.400
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2,941
14	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.329
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 24,473

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
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>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 4 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: Granite (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	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 68	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 27, 37, 47, 60 and 70	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Washington 10 Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
10	Withdrawal Rate	Att to Sch 5A, Line 3 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 3 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	-	-	-	-	-	-
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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)								
23	Received Volume	Line 15	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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)								
33	Received Volume	Line 25	-	-	-	-	-	-	-
34	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2							
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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)								
43	Received Volume	Line 35	-	-	-	-	-	-	-
44	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2							
45	Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	-	-	-	-
46	Variable Transportation Rate	Att to Sch 5A, Line 31 of Page 2							
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)								
53	Total Contract Recevied Volume	Sendout Optimization	-	-	-	-	-	-	-
54	Received Volume	Line 45	-	-	-	-	-	-	-
55	Percentage Allocated	Line 54 divided by Line 53	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
56	Total Contract Recevied Volume	Sendout Optimization						-	-
57	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2							
58	Delivered Volume	Line 56 times (1 - Line 57)	-	-	-	-	-	-	-
59	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2							
60	Variable Transportation Costs	Line 58 times Line 59	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61									
62	Transportation Segment 5								
63	Granite State Gas Transmission (Contract 10-010-FT-NN)								
64	Receipt Point: Westbrook, Newington, Eliot								
65	Delivery Point: Northern City Gates								
66	Received Volume	Line 58	-	-	-	-	-	-	-
67	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
68	City Gate Delivered Volume	Line 66 times (1 - Line 67)	-	-	-	-	-	-	-
69	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
70	Variable Transportation Costs	Line 68 times Line 69	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 38	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 30 and 40	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 1 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	-	-	-	-	-	-
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	Transportation Fuel Losses and Variable Charges								
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	Total Contract Recevied Volume	Sendout Optimization						76,955	456,767
24	Received Volume	Line 15	-	-	-	-	-	-	-
25	Percentage Allocated	Line 24 divided by Line 23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	Received Volume	Line 10	-	-	-	-	-	-	-
27	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2							
28	Delivered Volume	Line 26 times (1 - Line 27)	-	-	-	-	-	-	-
29	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2							
30	Variable Transportation Costs	Line 28 times Line 29	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31									
32	Transportation Segment 3								
33	Granite State Gas Transmission (Contract 10-010-FT-NN)								
34	Receipt Point: Pleasant St.								
35	Delivery Point: Northern City Gates								
36	Received Volume	Line 28	-	-	-	-	-	-	-
37	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	-	-	-	-	-	-	-
39	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
40	Variable Transportation Costs	Line 38 times Line 39	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
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 Contract 1 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	
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: Pleasant St.								
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	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
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	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
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 Commodity Price	Att to Sch 5A, Line 22 of Page 1							
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 13 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	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	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Gross Withdrawn Volume	Line 9	2,170	2,100	2,170	2,170	2,100	2,170	12,880
2	City Gate Delivered Volume	Line 15	2,170	2,100	2,170	2,170	2,100	2,170	12,880
3	Total Withdrawal Costs	Line 16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	2,170	2,100	2,170	2,170	2,100	2,170	12,880
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
13	Withdrawn Inventory Value	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	2,170	2,100	2,170	2,170	2,100	2,170	12,880
16	Total Withdrawal Costs	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	2015 Summer
1	Purchased Volumes	Line 22	2,170	2,100	2,170	2,170	2,100	2,170	12,880
2	Storage Delivered Volume	Line 24	2,170	2,100	2,170	2,170	2,100	2,170	12,880
3	Total Purchase Price	Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 8.988
4	Total Purchase Cost	Line 10 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 115,767
5	Variable Transportation Costs	Line 26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 15,585
6	Total Storage Delivered Costs	Line 13 plus Line 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 131,351
7	Average Delivered Price	Line 15 divided by Line 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 10.198
8									
9	LNG Supply Costs								
10	Purchased Volumes	Sendout Optimization	2,170	2,100	2,170	2,170	2,100	2,170	12,880
11	Monthly NYMEX Price	Att to Sch 5A, Line 22 of Page 1	$ 2.806	$ 2.845	$ 2.896	$ 2.913	$ 2.903	$ 2.929	$ 2.882
12	NYMEX Costs	Line 9 times Line 10	$ 6,089	$ 5,974	$ 6,284	$ 6,321	$ 6,096	$ 6,356	$ 37,121
13	NYMEX Basis Price	Att to Sch 5A, Line 15 of Page 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 6.106
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 78,645
15	Total Purchase Price	Line 10 plus Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 8.988
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 115,767
17									
18	Transportation Segment 3								
19	Trucking Contract								
20	Receipt Point: Distrigas Terminal								
21	Delivery Point: Northern LNG Facility (Lewiston, ME)								
22	Received Volume	Line 19 minus Line 31	2,170	2,100	2,170	2,170	2,100	2,170	12,880
23	Fuel Loss Rate	N/A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Storage Delivered Volume	Line 22 times (1 - Line 23)	2,170	2,100	2,170	2,170	2,100	2,170	12,880
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1.2100
26	Variable Transportation Costs	Line 24 times Line 25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 15,585

Schedule 7

Provided in Winter 2014–15 Cost-of-Gas Filing

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 837 therms/year

Comparison of Summer 2015 vs. Summer 2014

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)				58	109	149	148	134	96	**694**	49	24	16	14	15	25	**143**	**837**
Winter 2014- 2015																		
Customer Charge	units @	$20.01		$20.01	$20.01	$20.01	$20.01	$20.01	$20.01	$120.06								
First	50 units @	$0.5844		$29.22	$29.22	$29.22	$29.22	$29.22	$29.22	$175.32								
Over	50 units @	$0.4780		$3.82	$28.20	$47.32	$46.84	$40.15	$21.99	$188.33								
	COG 1	$1.0574		$61.33						$61.33								
	COG 2	$0.9644			$105.12					$105.12								
	COG 3	$0.9644				$143.70				$143.70								
	COG 4	$0.9644					$142.73			$142.73								
	COG 5	$0.9644						$129.23		$129.23								
	COG 6	$0.9644							$92.58	$92.58								
Winter Period 2014-2015 Avg. COG		$0.9722	*															
	LDAC	$0.0649		$3.76	$7.07	$9.67	$9.61	$8.70	$6.23	$45.04								
Summer 2015																		
Customer Charge	units @	$21.36	(2)								$21.36	$21.36	$21.36	$21.36	$21.36	$21.36	$128.16	
First	50 units @	$0.5449	(2)								$26.70	$13.08	$8.72	$7.63	$8.17	$13.62	$77.92	
Over	50 units @	$0.5449	(2)								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.3333									$16.33						$16.33	
	COG 2	$0.3333										$8.00					$8.00	
	COG 3	$0.3333											$5.33				$5.33	
	COG 4	$0.3333												$4.67			$4.67	
	COG 5	$0.3333													$5.00		$5.00	
	COG 6	$0.3333														$8.33	$8.33	
Summer Period 2015 Avg. COG		$0.3333	*															
	LDAC	$0.0446									$2.19	$1.07	$0.71	$0.62	$0.67	$1.12	$6.38	
TOTAL				$118.15	$189.63	$249.92	$248.41	$227.31	$170.03	$1,203.44	$66.58	$43.51	$36.12	$34.28	$35.20	$44.43	**$260.12**	$1,463.56

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms (1)				58	109	149	148	134	96	**694**	49	24	16	14	15	25	**143**	**837**
Winter 2013 - 2014																		
Customer Charge	units @	$20.01		$20.01	$20.01	$20.01	$20.01	$20.01	$20.01	$120.06								
First	50 units @	$0.5844		$29.22	$29.22	$29.22	$29.22	$29.22	$29.22	$175.32								
Over	50 units @	$0.4780		$3.82	$28.20	$47.32	$46.84	$40.15	$21.99	$188.33								
	COG 1	$1.1069		$64.20						$64.20								
	COG 2	$1.1069			$120.65					$120.65								
	COG 3	$1.0574				$157.55				$157.55								
	COG 4	$1.0574					$156.50			$156.50								
	COG 5	$1.0574						$141.69		$141.69								
	COG 6	$1.0574							$101.51	$101.51								
Winter Period 2013-2014 Avg. COG		$1.0693	*															
	LDAC	$0.0649		$3.76	$7.07	$9.67	$9.61	$8.70	$6.23	$45.04								
Summer 2014																		
Customer Charge	units @	$20.01									$20.01	$20.01	$20.01	$20.01	$20.01	$20.01	$120.06	
First	50 units @	$0.5104									$25.01	$12.25	$8.17	$7.15	$7.66	$12.76	$72.99	
Over	50 units @	$0.5104									$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.6833									$33.48						$33.48	
	COG 2	$0.6833										$16.40					$16.40	
	COG 3	$0.6153											$9.84				$9.84	
	COG 4	$0.6153												$8.61			$8.61	
	COG 5	$0.6153													$9.23		$9.23	
	COG 6	$0.6153														$15.38	$15.38	
Summer Period 2014 Avg. COG		$0.6500	*															
	LDAC	$0.0692									$3.39	$1.66	$1.11	$0.97	$1.04	$1.73	$9.90	
TOTAL				$121.02	$205.16	$263.77	$262.17	$239.77	$178.96	$1,270.85	$81.89	$50.32	$39.13	$36.74	$37.93	$49.88	**$295.89**	$1,566.75
Change				-$2.87	-$15.53	-$13.86	-$13.76	-$12.46	-$8.93	-$67.41	-$15.31	-$6.81	-$3.00	-$2.46	-$2.73	-$5.45	**-$35.77**	($103.19)
% Chg				-2.37%	-7.57%	-5.25%	-5.25%	-5.20%	-4.99%	-5.30%	-18.70%	-13.54%	-7.68%	-6.69%	-7.20%	-10.93%	**-12.09%**	-6.59%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2013 to October 2014

(2) Includes the 2015 Step 2 Adjustment

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 2,199 therms/year

Comparison of Summer 2015 vs. Summer 2014

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)				142	295	423	423	384	242	1,909	112	48	29	25	28	48	290	2,199
Winter 2014- 2015																		
Customer Charge	units @	$63.18		$63.18	$63.18	$63.18	$63.18	$63.18	$63.18	$379.08								
First	75 units @	$0.1513		$11.35	$11.35	$11.35	$11.35	$11.35	$11.35	$68.09								
Over	75 units @	$0.1513		$10.14	$33.29	$52.65	$52.65	$46.75	$25.27	$220.75								
	COG 1	$1.1217		$159.28						$159.28								
	COG 2	$0.9792			$288.86					$288.86								
	COG 3	$0.9792				$414.20				$414.20								
	COG 4	$0.9792					$414.20			$414.20								
	COG 5	$0.9792						$376.01		$376.01								
	COG 6	$0.9792							$236.97	$236.97								
Winter Period 2014-2015 Avg. COG		$0.9898	*															
	LDAC	$0.0437		$6.21	$12.89	$18.49	$18.49	$16.78	$10.58	$83.42								
Summer 2015																		
Customer Charge	units @	$67.45	(2)								$67.45	$67.45	$67.45	$67.45	$67.45	$67.45	$404.70	
First	75 units @	$0.1615	(2)								$12.11	$7.75	$4.68	$4.04	$4.52	$7.75	$40.86	
Over	75 units @	$0.1615	(2)								$5.98	$0.00	$0.00	$0.00	$0.00	$0.00	$5.98	
	COG 1	$0.3690									$41.33						$41.33	
	COG 2	$0.3690										$17.71					$17.71	
	COG 3	$0.3690											$10.70				$10.70	
	COG 4	$0.3690												$9.23			$9.23	
	COG 5	$0.3690													$10.33		$10.33	
	COG 6	$0.3690														$17.71	$17.71	
Summer Period 2015 Avg. COG		$0.3690	*															
	LDAC	$0.0234									$2.62	$1.12	$0.68	$0.59	$0.66	$1.12	$6.79	
TOTAL				$250.15	$409.57	$559.87	$559.87	$514.07	$347.34	$2,640.86	$129.49	$94.04	$83.51	$81.30	$82.96	$94.04	$565.33	$3,206.19

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)				142	295	423	423	384	242	1,909	112	48	29	25	28	48	290	2,199
Winter 2013 - 2014																		
Customer Charge	units @	$31.40		$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
First	75 units @	$0.3122		$23.42	$23.42	$23.42	$23.42	$23.42	$23.42	$140.49								
Over	75 units @	$0.2647		$17.73	$58.23	$92.12	$92.12	$81.79	$44.20	$386.20								
	COG 1	$0.8664		$123.03						$123.03								
	COG 2	$0.8664			$255.59					$255.59								
	COG 3	$0.9703				$410.44				$410.44								
	COG 4	$0.9703					$410.44			$410.44								
	COG 5	$0.9703						$372.60		$372.60								
	COG 6	$0.7330							$177.39	$177.39								
Winter Period 2013-2014 Avg. COG		$0.9164	*															
	LDAC	$0.0227		$3.22	$6.70	$9.60	$9.60	$8.72	$5.49	$43.33								
Summer 2014																		
Customer Charge	units @	$63.18									$63.18	$63.18	$63.18	$63.18	$63.18	$63.18	$379.08	
First	75 units @	$0.1513									$11.35	$7.26	$4.39	$3.78	$4.24	$7.26	$38.28	
Over	75 units @	$0.1513									$5.60	$0.00	$0.00	$0.00	$0.00	$0.00	$5.60	
	COG 1	$0.7209									$80.74						$80.74	
	COG 2	$0.7209										$34.60					$34.60	
	COG 3	$0.6529											$18.93				$18.93	
	COG 4	$0.6529												$16.32			$16.32	
	COG 5	$0.6529													$18.28		$18.28	
	COG 6	$0.6529														$31.34	$31.34	
Summer Period 2014 Avg. COG		$0.6904	*															
	LDAC	$0.0430									$4.82	$2.06	$1.25	$1.08	$1.20	$2.06	$12.47	
TOTAL				$198.80	$375.33	$566.97	$566.97	$517.92	$281.90	$2,507.89	$165.68	$107.11	$87.75	$84.36	$86.90	$103.85	$635.65	$3,143.54
Change				$51.35	$34.24	-$7.10	-$7.10	-$3.85	$65.44	$132.97	-$36.20	-$13.07	-$4.24	-$3.06	-$3.94	-$9.81	-$70.32	$62.65
% Chg				25.83%	9.12%	-1.25%	-1.25%	-0.74%	23.21%	5.30%	-21.85%	-12.20%	-4.83%	-3.63%	-4.54%	-9.45%	-11.06%	1.99%

*-Note- Weighted by usage.
(1) Actual Weather Normalized Usage from November 2013 to October 2014
(2) Includes the 2015 Step 2 Adjustment

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 24,028 therms/year

Comparison of Summer 2015 vs. Summer 2014

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,779	3,104	4,476	4,168	3,985	2,663	20,175	1,392	671	410	336	389	655	3,853	24,028
Winter 2014- 2015																	
Customer Charge	units @	$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$1,105.56								
All	units @	$0.1965	$349.57	$609.94	$879.53	$819.01	$783.05	$523.28	$3,964.39								
	COG 1	$1.1217	$1,995.50						$1,995.50								
	COG 2	$1.0722		$3,328.11					$3,328.11								
	COG 3	$1.0722			$4,799.17				$4,799.17								
	COG 4	$1.0722				$4,468.93			$4,468.93								
	COG 5	$1.0722					$4,272.72		$4,272.72								
	COG 6	$1.0722						$2,855.27	$2,855.27								
Winter Period 2014-2015 Avg. COG		$1.0766 *															
	LDAC	$0.0437	$77.74	$135.64	$195.60	$182.14	$174.14	$116.37	$881.65								
Summer 2015																	
Customer Charge	units @	$196.73 (2)								$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38	
All	units @	$0.1622 (2)								$225.78	$108.84	$66.50	$54.50	$63.10	$106.24	$624.96	
	COG 1	$0.3690								$513.65						$513.65	
	COG 2	$0.3690									$247.60					$247.60	
	COG 3	$0.3690										$151.29				$151.29	
	COG 4	$0.3690											$123.98			$123.98	
	COG 5	$0.3690												$143.54		$143.54	
	COG 6	$0.3690													$241.70	$241.70	
Summer Period 2015 Avg. COG		$0.3690 *															
	LDAC	$0.0234								$32.57	$15.70	$9.59	$7.86	$9.10	$15.33	$90.16	
		TOTAL	$2,607.08	$4,257.95	$6,058.56	$5,654.34	$5,414.17	$3,679.18	$27,671.29	$968.73	$568.87	$424.12	$383.08	$412.47	$559.99	**$3,317.25**	**$30,988.54**

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,779	3,104	4,476	4,168	3,985	2,663	20,175	1,392	671	410	336	389	655	3,853	24,028
Winter 2013 - 2014																	
Customer Charge	units @	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
All	units @	$0.2437	$433.54	$756.44	$1,090.80	$1,015.74	$971.14	$648.97	$4,916.65								
	COG 1	$0.8664	$1,541.33						$1,541.33								
	COG 2	$0.8664		$2,689.31					$2,689.31								
	COG 3	$0.9703			$4,343.06				$4,343.06								
	COG 4	$0.9703				$4,044.21			$4,044.21								
	COG 5	$0.9703					$3,866.65		$3,866.65								
	COG 6	$0.7330						$1,951.98	$1,951.98								
Winter Period 2013-2014 Avg. COG		$0.9138 *															
	LDAC	$0.0227	$40.38	$70.46	$101.61	$94.61	$90.46	$60.45	$457.97								
Summer 2014																	
Customer Charge	units @	$184.26								$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$1,105.56	
All	units @	$0.1519								$211.44	$101.92	$62.28	$51.04	$59.09	$99.49	$585.27	
	COG 1	$0.7209								$1,003.49						$1,003.49	
	COG 2	$0.7209									$483.72					$483.72	
	COG 3	$0.6529										$267.69				$267.69	
	COG 4	$0.6529											$219.37			$219.37	
	COG 5	$0.6529												$253.98		$253.98	
	COG 6	$0.6529													$427.65	$427.65	
Summer Period 2014 Avg. COG		$0.6893 *															
	LDAC	$0.0430								$59.86	$28.85	$17.63	$14.45	$16.73	$28.17	$165.68	
		TOTAL	$2,109.46	$3,610.42	$5,629.68	$5,248.78	$5,022.46	$2,755.61	$24,376.41	$1,459.05	$798.76	$531.86	$469.12	$514.05	$739.57	**$4,512.42**	**$28,888.83**
		Change	$497.62	$647.53	$428.88	$405.57	$391.71	$923.57	$3,294.88	-$490.32	-$229.90	-$107.74	-$86.05	-$101.58	-$179.58	**-$1,195.16**	**$2,099.72**
		% Chg	23.59%	17.93%	7.62%	7.73%	7.80%	33.52%	13.52%	-33.61%	-28.78%	-20.26%	-18.34%	-19.76%	-24.28%	**-26.49%**	**7.27%**

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2013 to October 2014

(2) Includes the 2015 Step 2 Adjustment

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 20,534 therms/year

Comparison of Summer 2015 vs. Summer 2014

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,661	1,902	2,344	2,367	2,248	1,832	12,354	1,591	1,351	1,291	1,270	1,263	1,414	8,180	20,534
Winter 2014- 2015																	
Customer Charge units @	$184.26		$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$1,105.56								
First 1,300 units @	$0.1424		$185.12	$185.12	$185.12	$185.12	$185.12	$185.12	$1,110.72								
Over 1,300 units @	$0.1160		$41.88	$69.83	$121.10	$123.77	$109.97	$61.71	$528.26								
COG 1	$1.0063		$1,671.46						$1,671.46								
COG 2	$0.9568			$1,819.83					$1,819.83								
COG 3	$0.9568				$2,242.74				$2,242.74								
COG 4	$0.9568					$2,264.75			$2,264.75								
COG 5	$0.9568						$2,150.89		$2,150.89								
COG 6	$0.9568							$1,752.86	$1,752.86								
Winter Period 2014-2015 Avg. COG	$0.9635	*															
LDAC	$0.0437		$72.59	$83.12	$102.43	$103.44	$98.24	$80.06	$539.87								
Summer 2015																	
Customer Charge units @	$196.73	(2)								$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38	
First 1,000 units @	$0.1183	(2)								$118.30	$118.30	$118.30	$118.30	$118.30	$118.30	$709.80	
Over 1,000 units @	$0.0958									$56.62	$33.63	$27.88	$25.87	$25.20	$39.66	$208.84	
COG 1	$0.2739									$435.77						$435.77	
COG 2	$0.2739										$370.04					$370.04	
COG 3	$0.2739											$353.60				$353.60	
COG 4	$0.2739												$347.85			$347.85	
COG 5	$0.2739													$345.94		$345.94	
COG 6	$0.2739														$387.29	$387.29	
Summer Period 2015 Avg. COG	$0.2739	*															
LDAC	$0.0234									$37.23	$31.61	$30.21	$29.72	$29.55	$33.09	$191.41	
TOTAL			$2,155.31	$2,342.16	$2,835.66	$2,861.34	$2,728.47	$2,264.01	$15,186.94	$844.65	$750.31	$726.72	$718.47	$715.72	$775.07	$4,530.94	$19,717.88

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,661	1,902	2,344	2,367	2,248	1,832	12,354	1,591	1,351	1,291	1,270	1,263	1,414	8,180	20,534
Winter 2013 - 2014																	
Customer Charge units @	$94.21		$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
First 1,300 units @	$0.2270		$295.10	$295.10	$295.10	$295.10	$295.10	$295.10	$1,770.60								
Over 1,300 units @	$0.1903		$68.70	$114.56	$198.67	$203.05	$180.40	$101.24	$866.63								
COG 1	$0.7762		$1,289.27						$1,289.27								
COG 2	$0.7762			$1,476.33					$1,476.33								
COG 3	$0.8801				$2,062.95				$2,062.95								
COG 4	$0.8801					$2,083.20			$2,083.20								
COG 5	$0.8801						$1,978.46		$1,978.46								
COG 6	$0.6428							$1,177.61	$1,177.61								
Winter Period 2013-2014 Avg. COG	$0.8149	*															
LDAC	$0.0227		$37.70	$43.18	$53.21	$53.73	$51.03	$41.59	$280.44								
Summer 2014																	
Customer Charge units @	$184.26									$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$1,105.56	
First 1,000 units @	$0.1108									$110.80	$110.80	$110.80	$110.80	$110.80	$110.80	$664.80	
Over 1,000 units @	$0.0897									$53.01	$31.48	$26.10	$24.22	$23.59	$37.14	$195.55	
COG 1	$0.6318									$1,005.19						$1,005.19	
COG 2	$0.6318										$853.56					$853.56	
COG 3	$0.5638											$727.87				$727.87	
COG 4	$0.5638												$716.03			$716.03	
COG 5	$0.5638													$712.08		$712.08	
COG 6	$0.5638														$797.21	$797.21	
Summer Period 2014 Avg. COG	$0.5883	*															
LDAC	$0.0430									$68.41	$58.09	$55.51	$54.61	$54.31	$60.80	$351.74	
TOTAL			$1,784.98	$2,023.38	$2,704.15	$2,729.29	$2,599.21	$1,709.75	$13,550.75	$1,421.68	$1,238.20	$1,104.54	$1,089.92	$1,085.04	$1,190.21	$7,129.59	$20,680.33
Change			$370.32	$318.78	$131.51	$132.05	$129.26	$554.26	$1,636.19	-$577.03	-$487.89	-$377.82	-$371.45	-$369.32	-$415.14	-$2,598.65	-$962.46
% Chg			20.75%	15.76%	4.86%	4.84%	4.97%	32.42%	12.07%	-40.59%	-39.40%	-34.21%	-34.08%	-34.04%	-34.88%	-36.45%	-4.65%

*-Note- Weighted by usage.
(1) Actual Weather Normalized Usage from November 2013 to October 2014
(2) Includes the 2015 Step 2 Adjustment

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2015 vs. Actual Summer 2014

Residential Heating	**Summer 2014**	**Summer 2015**
Customer Charge	$20.01	$21.36
First 50 Therms	$0.5104	$0.5449
Over 50 therms	$0.5104	$0.5449
LDAC	$0.0692	$0.0446
CGA	$0.6500	$0.3333

	Usage (Therms)	**Summer 2014 Bill Amount**	**Summer 2015 Bill Amount**	**Total Bill**		**Base Rate**		**COG**		**LDAC**	
	5	$26.16	$25.97	($0.18)	-0.7%	$0.17	0.6%	($1.58)	-6.0%	($0.12)	-0.5%
	10	$32.31	$30.59	($1.72)	-5.3%	$0.35	1.1%	($3.17)	-9.8%	($0.25)	-0.8%
	20	$44.60	$39.82	($4.79)	-10.7%	$0.69	1.5%	($6.33)	-14.2%	($0.49)	-1.1%
Average Monthly	25	$50.75	$44.43	($6.32)	-12.5%	$0.86	1.7%	($7.92)	-15.6%	($0.62)	-1.2%
	30	$56.90	$49.04	($7.85)	-13.8%	$1.04	1.8%	($9.50)	-16.7%	($0.74)	-1.3%
	45	$75.34	$62.89	($12.46)	-16.5%	$1.55	2.1%	($14.25)	-18.9%	($1.11)	-1.5%
	50	$81.49	$67.50	($13.99)	-17.2%	$1.73	2.1%	($15.84)	-19.4%	($1.23)	-1.5%
	75	$112.23	$90.57	($21.66)	-19.3%	$2.59	2.3%	($23.75)	-21.2%	($1.85)	-1.6%
	125	$173.71	$136.71	($37.00)	-21.3%	$4.32	2.5%	($39.59)	-22.8%	($3.08)	-1.8%
	150	$204.45	$159.78	($44.67)	-21.8%	$5.18	2.5%	($47.51)	-23.2%	($3.69)	-1.8%
	200	$265.93	$205.92	($60.01)	-22.6%	$6.91	2.6%	($63.34)	-23.8%	($4.92)	-1.9%

Schedule 9

Northern Utilities, Inc.
New Hampshire Division
Schedule 9
Page 1 of 1

Northern Utilities New Hampshire Division
Period Covered: May 1, 2015 - October 31, 2015
Variance Analysis

		2014 Summer (6 months actual)			Forecast Summer 2015 (6 months proposed)			Variance		
1	Therm Sales	6,433,420			7,371,305			937,885		
2 3 4		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
5										
6	Demand Charges		$ 925,646	$ 0.1439		$ 901,217	$ 0.1223		$ (24,429)	$ (0.0216)
7										
8	Purchased Gas		2,691,523	0.4184		1,829,100	0.2481		$ (862,422)	$ (0.1702)
9										
10	Storage & Peaking Gas		241,294	0.0375		80,863	0.0110		$ (160,432)	$ (0.0265)
11										
12	Hedging (Gain)/Loss		-	-		-	-		-	-
13										
14										
15	Total Volumes and Cost		$ 3,858,463	$ 0.5998	$ -	$ 2,811,180	$ 0.3814	$ -	$ (1,047,283)	$ (0.2184)
16										
17	Prior Period Balance		$401,941	$ 0.0625		$ (470,799)	$ (0.0639)		$ (872,740)	$ (0.1263)
18						$ -	$ -		$ -	$ -
19	Interest		$ (702)	$ (0.0001)		(11,671)	$ (0.0016)		(10,969)	$ (0.0015)
20	Refunds from Suppliers		-	$ -		-	$ -		-	$ -
21	Off-system Sales		(101,471)	$ (0.0158)					101,471	$ 0.0158
22	Prior Period Adjustment									
23	ATV Reconciliation		(88,962)	$ (0.0138)		-	$ -		88,962	$ 0.0138
24	Capacity Release & Asset Management		-	$ -		$ -	$ -		-	$ -
25	Working Capital Allowance		(387)	$ (0.0001)		1,928	$ 0.0003		2,315	$ 0.0003
26	Bad Debt Allowance		921	$ 0.0001		$ 30,253	$ 0.0041		29,332	$ 0.0040
27	Fuel Inventory Financing		-	$ -		-	$ -		-	$ -
28	Local Production and Storage			$ -		-	$ -		-	$ -
29	Misc Overhead		97,718	$ 0.0152		95,875	$ 0.0130		(1,843)	$ (0.0022)
30										
31	Total Anticipated Indirect Cost of Gas		$309,057	$ 0.0480		(354,413)	$ (0.0481)		(663,471)	$ (0.0961)
32	Total Adjusted Cost		4,167,521	$ 0.6478		2,456,767	$ 0.3333		(1,710,754)	$ (0.3145)

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**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**	
2	**Total Therms**									
3	Res Heat	409,365	396,159	401,430	409,365	396,159	409,365	4,812,004	2,421,843	Schedule 10B, LN 52
4	Res General	12,137	11,746	11,902	12,137	11,746	12,137	142,670	71,805	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	74,998	72,578	73,544	74,998	72,578	74,998	881,584	443,694	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	148,996	144,190	146,109	148,996	144,190	148,996	1,751,425	881,478	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	101,757	98,474	99,785	101,757	98,474	101,757	1,196,133	602,004	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	153,546	148,593	150,571	153,546	148,593	153,546	1,804,907	908,395	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	17,751	17,179	17,407	17,751	17,179	17,751	208,663	105,018	Schedule 10B, LN 58
10	G42 High Annual-High Winter	20,159	19,509	19,769	20,159	19,509	20,159	236,970	119,265	Schedule 10B, LN 59
11	Total Firm Sales	938,709	908,429	920,518	938,709	908,429	938,709	11,034,355	5,553,503	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	43.61%	43.61%	43.61%	43.61%	43.61%	43.61%			LN 3 / LN 11
15	Res General	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%			LN 5 / LN 11
17	G40 Low Annual-High Winter	15.87%	15.87%	15.87%	15.87%	15.87%	15.87%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	10.84%	10.84%	10.84%	10.84%	10.84%	10.84%			LN 7 / LN 11
19	G41 Med Annual-High Winter	16.36%	16.36%	16.36%	16.36%	16.36%	16.36%			LN 8 / LN 11
20	G52 High Annual-Low Winter	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%			LN 9 / LN 11
21	G42 High Annual-High Winter	2.15%	2.15%	2.15%	2.15%	2.15%	2.15%			LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			LN 11 / LN 11
23										
24	**PIPELINE BASE DEMAND COSTS**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 56,360	$ 676,314	$ 338,157	Schedule 1A, LN 69
26	Res Heat	$ 24,578	$ 24,578	$ 24,578	$ 24,578	$ 24,578	$ 24,578	$ 294,936	$ 147,468	LN 25 * LN 14
27	Res General	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 8,745	$ 4,372	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 4,503	$ 4,503	$ 4,503	$ 4,503	$ 4,503	$ 4,503	$ 54,034	$ 27,017	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 8,946	$ 8,946	$ 8,946	$ 8,946	$ 8,946	$ 8,946	$ 107,348	$ 53,674	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 73,313	$ 36,657	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 9,219	$ 9,219	$ 9,219	$ 9,219	$ 9,219	$ 9,219	$ 110,626	$ 55,313	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 1,066	$ 1,066	$ 1,066	$ 1,066	$ 1,066	$ 1,066	$ 12,789	$ 6,395	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,210	$ 1,210	$ 1,210	$ 1,210	$ 1,210	$ 1,210	$ 14,524	$ 7,262	LN 25 * LN 21
34										
35	Residential	$ 25,307	$ 25,307	$ 25,307	$ 25,307	$ 25,307	$ 25,307	$ 303,680	$ 151,840	LN 26 + LN 27
36	SALES HLF CLASSES	$ 11,678	$ 11,678	$ 11,678	$ 11,678	$ 11,678	$ 11,678	$ 140,136	$ 70,068	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 19,375	$ 19,375	$ 19,375	$ 19,375	$ 19,375	$ 19,375	$ 232,498	$ 116,249	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	18,499	1,536	16,963	45.13%	Company Analysis
41	Res General	227	56	171	0.45%	Company Analysis
42	G50 Low Annual-Low Winter	984	324	660	1.76%	Company Analysis
43	G40 Low Annual-High Winter	10,253	512	9,741	25.92%	Company Analysis
44	G51 Med Annual-Low Winter	1,249	384	864	2.30%	Company Analysis
45	G41 Med Annual-High Winter	8,726	631	8,094	21.54%	Company Analysis
46	G52 High Annual-Low Winter	186	19	167	0.44%	Company Analysis
47	G42 High Annual-High Winter	980	54	926	2.46%	Company Analysis
48	TOTAL	41,103	3,517	37,586	100.00%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

51		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 29,160	$ 4,333	$ -	$ 693	$ 5,920	$ 55,477	$ 2,832,644	$ 95,582	Schedule 1A, LN 70
53										
54	Res Heat	$ 13,160	$ 1,955	$ -	$ 313	$ 2,672	$ 25,037	$ 1,278,389	$ 43,137	LN 40 Col D * LN 52
55	Res General	$ 132	$ 20	$ -	$ 3	$ 27	$ 252	$ 12,854	$ 434	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 512	$ 76	$ -	$ 12	$ 104	$ 974	$ 49,737	$ 1,678	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 7,557	$ 1,123	$ -	$ 180	$ 1,534	$ 14,378	$ 734,126	$ 24,772	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 671	$ 100	$ -	$ 16	$ 136	$ 1,276	$ 65,146	$ 2,198	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 6,280	$ 933	$ -	$ 149	$ 1,275	$ 11,947	$ 610,015	$ 20,584	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 129	$ 19	$ -	$ 3	$ 26	$ 246	$ 12,576	$ 424	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 719	$ 107	$ -	$ 17	$ 146	$ 1,367	$ 69,801	$ 2,355	LN 47 Col D * LN 52
62	TOTAL	$ 29,160	$ 4,333	$ -	$ 693	$ 5,920	$ 55,477	$ 2,832,644	$ 95,582	Sum LN 54 : LN 61
63										
64	Residential	$ 13,292	$ 1,975	$ -	$ 316	$ 2,698	$ 25,289	$ 1,291,243	$ 43,571	LN 54 + LN 55
65	SALES HLF CLASSES	$ 1,312	$ 195	$ -	$ 31	$ 266	$ 2,496	$ 127,459	$ 4,301	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 14,555	$ 2,163	$ -	$ 346	$ 2,955	$ 27,692	$ 1,413,943	$ 47,711	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

69		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 142,615	$ 21,191	$ -	$ 3,390	$ 28,952	$ 271,331	$ 13,854,026	$ 467,478	Schedule 1A, LN 73
71										
72	Res Heat	$ 64,363	$ 9,563	$ -	$ 1,530	$ 13,066	$ 122,453	$ 6,252,403	$ 210,975	LN 40 Col D * LN 70
73	Res General	$ 647	$ 96	$ -	$ 15	$ 131	$ 1,231	$ 62,865	$ 2,121	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 2,504	$ 372	$ -	$ 60	$ 508	$ 4,764	$ 243,257	$ 8,208	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 36,961	$ 5,492	$ -	$ 879	$ 7,503	$ 70,320	$ 3,590,499	$ 121,155	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 3,280	$ 487	$ -	$ 78	$ 666	$ 6,240	$ 318,619	$ 10,751	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 30,712	$ 4,563	$ -	$ 730	$ 6,235	$ 58,432	$ 2,983,488	$ 100,672	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 633	$ 94	$ -	$ 15	$ 129	$ 1,205	$ 61,507	$ 2,075	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 3,514	$ 522	$ -	$ 84	$ 713	$ 6,686	$ 341,388	$ 11,519	LN 47 Col D * LN 70
80	TOTAL	$ 142,615	$ 21,191	$ -	$ 3,390	$ 28,952	$ 271,331	$ 13,854,026	$ 467,478	Sum LN 72 : LN 79
81										
82	Residential	$ 65,010	$ 9,660	$ -	$ 1,545	$ 13,198	$ 123,684	$ 6,315,268	$ 213,097	LN 72 + LN 73
83	SALES HLF CLASSES	$ 6,417	$ 954	$ -	$ 153	$ 1,303	$ 12,209	$ 623,383	$ 21,035	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 71,188	$ 10,577	$ -	$ 1,692	$ 14,452	$ 135,437	$ 6,915,375	$ 233,346	LN 75 + LN 77 + LN 79

85

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

87		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,741,845)	$ -	Schedule 1A, LN 76
89										
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,140,023)	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (21,517)	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (83,260)	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,228,927)	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (109,054)	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,021,165)	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (21,052)	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (116,848)	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,741,845)	$ -	Sum LN 90 : LN 97
99										
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,161,539)	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (213,367)	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,366,939)	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

105		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
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		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 78
125										
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135										
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133

139

140 **TOTAL NON-BASE CAPACITY COSTS**

141		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
142	Res Heat	$ 77,523	$ 11,519	$ -	$ 1,843	$ 15,738	$ 147,490	$ 5,390,769	$ 254,112	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 779	$ 116	$ -	$ 19	$ 158	$ 1,483	$ 54,202	$ 2,555	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 3,016	$ 448	$ -	$ 72	$ 612	$ 5,738	$ 209,735	$ 9,887	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 44,518	$ 6,615	$ -	$ 1,058	$ 9,038	$ 84,698	$ 3,095,698	$ 145,926	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 3,951	$ 587	$ -	$ 94	$ 802	$ 7,516	$ 274,710	$ 12,949	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 36,992	$ 5,496	$ -	$ 879	$ 7,510	$ 70,379	$ 2,572,339	$ 121,256	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 763	$ 113	$ -	$ 18	$ 155	$ 1,451	$ 53,031	$ 2,500	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 4,233	$ 629	$ -	$ 101	$ 859	$ 8,053	$ 294,342	$ 13,875	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 171,774	$ 25,523	$ -	$ 4,083	$ 34,871	$ 326,808	$ 11,944,825	$ 563,060	Sum LN 142 : LN 149
151										
152	Residential	$ 78,302	$ 11,635	$ -	$ 1,861	$ 15,896	$ 148,973	$ 5,444,971	$ 256,667	LN 142 + LN 143
153	SALES HLF CLASSES	$ 7,729	$ 1,148	$ -	$ 184	$ 1,569	$ 14,705	$ 537,476	$ 25,336	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 85,743	$ 12,740	$ -	$ 2,038	$ 17,406	$ 163,129	$ 5,962,378	$ 281,057	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

157		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer	
158	Res Heat	$ 102,101	$ 36,097	$ 24,578	$ 26,421	$ 40,316	$ 172,068	$ 5,685,705	$ 401,580	LN 142 + LN 26
159	Res General	$ 1,508	$ 845	$ 729	$ 747	$ 887	$ 2,212	$ 62,946	$ 6,927	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 7,519	$ 4,951	$ 4,503	$ 4,575	$ 5,115	$ 10,241	$ 263,768	$ 36,903	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 53,464	$ 15,560	$ 8,946	$ 10,004	$ 17,983	$ 93,643	$ 3,203,046	$ 199,600	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 10,060	$ 6,696	$ 6,109	$ 6,203	$ 6,911	$ 13,625	$ 348,023	$ 49,606	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 46,211	$ 14,715	$ 9,219	$ 10,098	$ 16,728	$ 79,597	$ 2,682,964	$ 176,569	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,828	$ 1,179	$ 1,066	$ 1,084	$ 1,221	$ 2,517	$ 65,820	$ 8,894	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 5,443	$ 1,839	$ 1,210	$ 1,311	$ 2,070	$ 9,263	$ 308,866	$ 21,137	LN 149 + LN 33
166	TOTAL	$ 228,134	$ 81,883	$ 56,360	$ 60,443	$ 91,231	$ 383,168	$ 12,621,140	$ 901,217	Sum LN 158 : LN 165
167										
168	Residential	$ 103,609	$ 36,941	$ 25,307	$ 27,168	$ 41,203	$ 174,280	$ 5,748,651	$ 408,507	LN 158 + LN 159
169	SALES HLF CLASSES	$ 19,407	$ 12,826	$ 11,678	$ 11,862	$ 13,247	$ 26,383	$ 677,612	$ 95,404	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 105,118	$ 32,115	$ 19,375	$ 21,413	$ 36,781	$ 182,504	$ 6,194,876	$ 397,306	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								19%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								81%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2014 - 2015 Period

	Forecasted Normal Sales By Class- Therms														
	Calendar Month Firm Sales Volumes														
Line No.	Normal Winter	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
1	Res Heat	1,868,718	2,753,021	3,475,584	2,905,490	2,239,772	1,319,914	658,894	438,844	398,587	414,345	453,609	849,300	17,776,077	3,213,580
2	Res General	24,898	36,680	46,307	38,711	29,842	17,586	19,546	13,018	11,824	12,292	13,456	25,195	289,355	95,331
3	**Total Residential**	**1,893,616**	**2,789,700**	**3,521,890**	**2,944,201**	**2,269,613**	**1,337,500**	**678,440**	**451,862**	**410,412**	**426,637**	**467,066**	**874,495**	**18,065,432**	**3,308,911**
4	G50 Low Annual-Low Winter	108,395	159,689	201,601	168,533	129,918	76,562	120,779	80,442	73,063	75,952	83,149	155,682	1,433,766	589,067
5	G40 Low Annual-High Winter	1,005,941	1,481,966	1,870,926	1,564,041	1,205,682	710,517	239,949	159,813	145,153	150,892	165,191	309,289	9,009,361	1,170,288
6	G51 Med Annual-Low Winter	147,015	216,585	273,430	228,580	176,207	103,840	163,873	109,144	99,132	103,051	112,817	211,229	1,944,904	799,246
7	G41 Med Annual-High Winter	829,848	1,222,543	1,543,414	1,290,251	994,623	586,139	247,276	164,694	149,586	155,500	170,235	318,734	7,672,841	1,206,024
8	G52 High Annual-Low Winter	28,732	42,328	53,438	44,673	34,437	20,294	28,587	19,040	17,293	17,977	19,681	36,848	363,328	139,427
9	G42 High Annual-High Winter	98,767	145,505	183,694	153,563	118,378	69,761	32,465	21,623	19,639	20,416	22,351	41,847	928,010	158,342
10	**Total C&I**	**2,218,698**	**3,268,617**	**4,126,504**	**3,449,641**	**2,659,245**	**1,567,112**	**832,930**	**554,757**	**503,868**	**523,788**	**573,423**	**1,073,629**	**21,352,211**	**4,062,394**
11	**Total Sales**	**4,112,314**	**6,058,317**	**7,648,394**	**6,393,843**	**4,928,858**	**2,904,612**	**1,511,370**	**1,006,619**	**914,279**	**950,425**	**1,040,489**	**1,948,123**	**39,417,643**	**7,371,305**
12															
13	Residential Heat & Non Heat	1,893,616	2,789,700	3,521,890	2,944,201	2,269,613	1,337,500	678,440	451,862	410,412	426,637	467,066	874,495	18,065,432	3,308,911
14	SALES HLF CLASSES	284,142	418,603	528,470	441,786	340,562	200,696	313,239	208,627	189,489	196,980	215,647	403,758	3,741,998	1,527,740
15	SALES LLF CLASSES	1,934,556	2,850,014	3,598,034	3,007,855	2,318,683	1,366,417	519,691	346,130	314,379	326,808	357,776	669,870	17,610,213	2,534,654
16	**Total Firm Sales**	**4,112,314**	**6,058,317**	**7,648,394**	**6,393,843**	**4,928,858**	**2,904,612**	**1,511,370**	**1,006,619**	**914,279**	**950,425**	**1,040,489**	**1,948,123**	**39,417,643**	**7,371,305**
17															
18	**ESTIMATED SENDOUT BY CLASS - Therms**														
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)														
20	Normal Winter	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**SUMMER**
21	Res Heat	1,881,294	2,771,440	3,498,789	2,924,920	2,254,823	1,328,870	663,476	441,970	401,430	417,299	456,827	855,162	17,896,299	3,236,164
22	Res General	25,054	36,908	46,594	38,951	30,028	17,697	19,672	13,104	11,902	12,372	13,544	25,355	291,180	95,949
23	G50 Low Annual-Low Winter	109,073	160,681	202,850	169,579	130,729	77,045	121,554	80,969	73,544	76,451	83,692	156,673	1,442,840	592,884
24	G40 Low Annual-High Winter	1,012,230	1,491,166	1,882,511	1,573,745	1,213,207	715,004	241,490	160,859	146,109	151,884	166,269	311,260	9,065,734	1,177,871
25	G51 Med Annual-Low Winter	147,934	217,930	275,123	229,998	177,307	104,496	164,925	109,859	99,785	103,729	113,553	212,575	1,957,214	804,425
26	G41 Med Annual-High Winter	835,036	1,230,133	1,552,971	1,298,255	1,000,831	589,840	248,864	165,771	150,571	156,522	171,347	320,765	7,720,905	1,213,839
27	G52 High Annual-Low Winter	28,912	42,591	53,769	44,950	34,652	20,422	28,771	19,165	17,407	18,095	19,809	37,083	365,625	140,330
28	G42 High Annual-High Winter	99,384	146,408	184,832	154,516	119,117	70,202	32,674	21,765	19,769	20,550	22,496	42,114	933,827	159,368
29	**Subtotal**														
30	Residential	1,906,348	2,808,347	3,545,382	2,963,871	2,284,851	1,346,566	683,147	455,073	413,332	429,671	470,372	880,517	18,187,480	3,332,113
31	SALES HLF CLASSES	285,919	421,201	531,742	444,527	342,688	201,963	315,250	209,992	190,737	198,275	217,055	406,331	3,765,679	1,537,640
32	SALES LLF CLASSES	1,946,650	2,867,707	3,620,314	3,026,516	2,333,155	1,375,046	523,028	348,395	316,449	328,955	360,112	674,139	17,720,466	2,551,078
33	**Total Firm Sales**	4,138,917	6,097,256	7,697,438	6,434,914	4,960,694	2,923,575	1,521,425	1,013,461	920,518	956,901	1,047,538	1,960,987	39,673,625	7,420,831

Northern Utilities - NEW HAMPSHIRE DIVISION
2014 - 2015 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Firm Sales	
1	Res Heat	Company Analysis
2	Res General	Company Analysis
3	**Total Residential**	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	Company Analysis
5	G40 Low Annual-High Winter	Company Analysis
6	G51 Med Annual-Low Winter	Company Analysis
7	G41 Med Annual-High Winter	Company Analysis
8	G52 High Annual-Low Winter	Company Analysis
9	G42 High Annual-High Winter	Company Analysis
10	**Total C&I**	Sum LN 4 : LN 9
11	**Total Sales**	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	**Total Firm Sales**	Sum LN 13 : LN 15
17		
18	**ESTIMATED SENDOUT BY CLASS - Therms**	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	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	13,205
37	Res General	392
38	G50 Low Annual-Low Winter	2,419
39	G40 Low Annual-High Winter	4,806
40	G51 Med Annual-Low Winter	3,282
41	G41 Med Annual-High Winter	4,953
42	G52 High Annual-Low Winter	573
43	G42 High Annual-High Winter	650
44	**Subtotal**	
45	Residential	13,597
46	SALES HLF CLASSES	6,274
47	SALES LLF CLASSES	10,410
48	**Total Firm Sales**	**30,281**

49	**BASE SENDOUT BY CLASS - Therms**														
50	Days per Month	30	31	31	28	31	30	31	30	31	31	30	31		
51		**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**SUMMER**
52	Res Heat	396,159	409,365	409,365	369,749	409,365	396,159	409,365	396,159	401,430	409,365	396,159	409,365	4,812,004	2,421,843
53	Res General	11,746	12,137	12,137	10,963	12,137	11,746	12,137	11,746	11,902	12,137	11,746	12,137	142,670	71,805
54	G50 Low Annual-Low Winter	72,578	74,998	74,998	67,740	74,998	72,578	74,998	72,578	73,544	74,998	72,578	74,998	881,584	443,694
55	G40 Low Annual-High Winter	144,190	148,996	148,996	134,577	148,996	144,190	148,996	144,190	146,109	148,996	144,190	148,996	1,751,425	881,478
56	G51 Med Annual-Low Winter	98,474	101,757	101,757	91,909	101,757	98,474	101,757	98,474	99,785	101,757	98,474	101,757	1,196,133	602,004
57	G41 Med Annual-High Winter	148,593	153,546	153,546	138,687	153,546	148,593	153,546	148,593	150,571	153,546	148,593	153,546	1,804,907	908,395
58	G52 High Annual-Low Winter	17,179	17,751	17,751	16,033	17,751	17,179	17,751	17,179	17,407	17,751	17,179	17,751	208,663	105,018
59	G42 High Annual-High Winter	19,509	20,159	20,159	18,208	20,159	19,509	20,159	19,509	19,769	20,159	19,509	20,159	236,970	119,265
60	**Subtotal**														
61	Residential	407,905	421,502	421,502	380,711	421,502	407,905	421,502	407,905	413,332	421,502	407,905	421,502	4,954,674	2,493,647
62	SALES HLF CLASSES	188,231	194,506	194,506	175,683	194,506	188,231	194,506	188,231	190,737	194,506	188,231	194,506	2,286,380	1,150,717
63	SALES LLF CLASSES	312,292	322,702	322,702	291,473	322,702	312,292	322,702	312,292	316,449	322,702	312,292	322,702	3,793,302	1,909,139
64	**Total Firm Sales**	908,429	938,709	938,709	847,867	938,709	908,429	938,709	908,429	920,518	938,709	908,429	938,709	11,034,355	5,553,503

65															
66	**REMAINING SENDOUT BY CLASS - Therms**														
67		**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**SUMMER**
68	Res Heat	1,485,135	2,362,075	3,089,424	2,555,171	1,845,458	932,710	254,111	45,811	-	7,934	60,668	445,798	13,084,296	814,322
69	Res General	13,308	24,770	34,457	27,989	17,891	5,951	7,534	1,358	-	235	1,799	13,218	148,510	24,144
70	G50 Low Annual-Low Winter	36,494	85,683	127,852	101,839	55,731	4,467	46,557	8,391	-	1,453	11,114	81,676	561,256	149,190
71	G40 Low Annual-High Winter	868,040	1,342,170	1,733,514	1,439,167	1,064,211	570,814	92,493	16,669	-	2,887	22,079	162,264	7,314,309	296,393
72	G51 Med Annual-Low Winter	49,460	116,173	173,367	138,089	75,550	6,021	63,168	11,384	-	1,972	15,079	110,818	761,081	202,421
73	G41 Med Annual-High Winter	686,443	1,076,587	1,399,425	1,159,568	847,285	441,247	95,318	17,178	-	2,975	22,753	167,219	5,915,998	305,444
74	G52 High Annual-Low Winter	11,733	24,840	36,017	28,916	16,901	3,243	11,020	1,986	-	344	2,630	19,332	156,963	35,312
75	G42 High Annual-High Winter	79,875	126,249	164,672	136,307	98,958	50,693	12,514	2,255	-	391	2,987	21,954	696,856	40,102
76	**Subtotal**														
77	Residential	1,498,443	2,386,845	3,123,881	2,583,160	1,863,349	938,662	261,646	47,168	-	8,170	62,467	459,016	13,232,806	838,466
78	SALES HLF CLASSES	97,687	226,695	337,236	268,844	148,182	13,732	120,745	21,761	-	3,769	28,823	211,825	1,479,300	386,923
79	SALES LLF CLASSES	1,634,358	2,545,005	3,297,612	2,735,043	2,010,453	1,062,754	200,326	36,103	-	6,253	47,820	351,437	13,927,164	641,939
80	**Total Firm Sales**	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147	582,716	105,033	-	18,192	139,110	1,022,278	28,639,269	1,867,328

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base and 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
Billed Distribution Service Volumes and Meter Counts

	Total Division Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	555,928	529,156	26,772	5.1%	12,168	14,604	493,031	62,897	12.8%	22,153	40,744
Jun	429,229	414,423	14,806	3.6%	9,962	4,844	380,854	48,375	12.7%	17,113	31,262
Jul	350,230	333,540	16,690	5.0%	8,467	8,223	311,193	39,037	12.5%	13,986	25,052
Aug	357,240	327,519	29,721	9.1%	8,320	21,402	317,208	40,032	12.6%	14,277	25,755
Sep	364,504	339,140	25,364	7.5%	6,614	18,750	323,141	41,363	12.8%	14,536	26,827
Oct	461,920	415,928	45,991	11.1%	6,185	39,807	409,469	52,450	12.8%	18,456	33,994
Summer	2,519,052	2,359,706	159,346	6.8%	51,929	107,417	2,234,898	284,154	12.7%	100,523	183,631

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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	30,992	30,295	697	2.3%	29,659	1,333	4.5%
Jun	30,934	30,208	726	2.4%	29,604	1,330	4.5%
Jul	30,846	30,082	764	2.5%	29,519	1,327	4.5%
Aug	30,881	30,116	765	2.5%	29,551	1,330	4.5%
Sep	30,940	30,348	592	2.0%	29,608	1,332	4.5%
Oct	31,182	30,725	457	1.5%	29,837	1,345	4.5%
Summer	30,962	30,296	667	2.2%	29,630	1,333	4.5%

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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	17.94	17.47	0.47	2.7%	16.62	1.31	7.9%
Jun	13.88	13.72	0.16	1.1%	12.86	1.01	7.9%
Jul	11.35	11.09	0.27	2.4%	10.54	0.81	7.7%
Aug	11.57	10.88	0.69	6.4%	10.73	0.83	7.8%
Sep	11.78	11.18	0.61	5.4%	10.91	0.87	7.9%
Oct	14.81	13.54	1.28	9.4%	13.72	1.09	7.9%
Summer	81.36	77.89	3.47	4.5%	75.43	5.93	7.9%

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

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

	Residential Non-Heat Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	2,154	2,484	-330	-13.3%	-28	-302	2,486	-332	-13.4%	157	-490
Jun	2,427	2,019	408	20.2%	-32	440	2,802	-374	-13.4%	177	-552
Jul	730	1,843	-1,113	-60.4%	-24	-1,089	842	-113	-13.4%	53	-166
Aug	1,376	1,680	-305	-18.1%	190	-495	1,588	-212	-13.4%	100	-313
Sep	1,352	1,619	-267	-16.5%	164	-430	1,561	-209	-13.4%	99	-307
Oct	1,494	1,826	-331	-18.2%	203	-535	1,725	-230	-13.4%	109	-340
Summer	9,533	11,471	-1,938	-16.9%	527	-2,465	11,003	-1,470	-13.4%	696	-2,167

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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1,607	1,625	-18	-1.1%	1,511	96	6.3%
Jun	1,602	1,628	-26	-1.6%	1,507	95	6.3%
Jul	1,597	1,618	-21	-1.3%	1,502	95	6.3%
Aug	1,730	1,554	176	11.3%	1,627	103	6.3%
Sep	1,703	1,547	156	10.1%	1,602	101	6.3%
Oct	1,671	1,504	167	11.1%	1,572	99	6.3%
Summer	1,652	1,579	72	4.6%	1,554	98	6.3%

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

	Total Division Use Per Meter						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1.34	1.53	-0.19	-12.3%	1.65	-0.30	-18.5%
Jun	1.51	1.24	0.27	22.1%	1.86	-0.34	-18.5%
Jul	0.46	1.14	-0.68	-59.9%	0.56	-0.10	-18.5%
Aug	0.80	1.08	-0.29	-26.5%	0.98	-0.18	-18.5%
Sep	0.79	1.05	-0.25	-24.1%	0.97	-0.18	-18.5%
Oct	0.89	1.21	-0.32	-26.4%	1.10	-0.20	-18.5%
Summer	5.77	7.26	-1.49	-20.5%	7.08	-1.32	-18.6%

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
Billed Distribution Service Volumes and Meter Counts

	Residential Heat Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	103,615	107,292	-3,676	-3.4%	3,128	-6,804	95,658	7,958	8.3%	4,488	3,470
Jun	58,985	54,241	4,745	8.7%	1,552	3,193	54,455	4,530	8.3%	2,555	1,975
Jul	36,782	35,924	858	2.4%	978	-120	33,957	2,825	8.3%	1,593	1,232
Aug	33,792	31,297	2,496	8.0%	568	1,927	31,197	2,595	8.3%	1,464	1,132
Sep	34,615	34,211	404	1.2%	373	31	31,956	2,658	8.3%	1,499	1,159
Oct	53,568	56,904	-3,336	-5.9%	390	-3,726	49,454	4,114	8.3%	2,320	1,794
Summer	321,358	319,868	1,490	0.5%	6,422	-4,932	296,678	24,680	8.3%	13,919	10,761

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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	22,689	22,046	643	2.9%	21,672	1,017	4.7%
Jun	22,656	22,026	630	2.9%	21,641	1,015	4.7%
Jul	22,601	22,002	599	2.7%	21,588	1,013	4.7%
Aug	22,504	22,103	401	1.8%	21,496	1,008	4.7%
Sep	22,546	22,303	243	1.1%	21,536	1,010	4.7%
Oct	22,738	22,583	155	0.7%	21,719	1,019	4.7%
Summer	22,622	22,177	445	2.0%	21,609	1,014	4.7%

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

	Total Division Use Per Meter						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	4.57	4.87	-0.30	-6.2%	4.41	0.15	3.5%
Jun	2.60	2.46	0.14	5.7%	2.52	0.09	3.5%
Jul	1.63	1.63	-0.01	-0.3%	1.57	0.05	3.5%
Aug	1.50	1.42	0.09	6.0%	1.45	0.05	3.5%
Sep	1.54	1.53	0.00	0.1%	1.48	0.05	3.5%
Oct	2.36	2.52	-0.16	-6.5%	2.28	0.08	3.5%
Summer	14.21	14.42	-0.22	-1.5%	13.73	0.48	3.5%

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
Billed Distribution Service Volumes and Meter Counts

	Total Division C&I Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	450,159	419,381	30,778	7.3%	4,574	26,204	394,887	55,272	14.0%	13,430	41,841
Jun	367,817	358,163	9,654	2.7%	6,640	3,013	323,597	44,219	13.7%	11,003	33,217
Jul	312,718	295,773	16,946	5.7%	8,503	8,442	276,393	36,325	13.1%	9,406	26,919
Aug	322,072	294,542	27,530	9.3%	8,553	18,978	284,423	37,649	13.2%	9,670	27,978
Sep	328,537	303,310	25,227	8.3%	8,968	16,259	289,624	38,913	13.4%	9,854	29,059
Oct	406,858	357,199	49,659	13.9%	7,233	42,426	358,291	48,567	13.6%	12,392	36,175
Summer	2,188,161	2,028,367	159,794	7.9%	46,198	113,595	1,927,216	260,945	13.5%	65,736	195,208

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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	6,696	6,624	72	1.1%	6,476	220	3.4%
Jun	6,676	6,554	122	1.9%	6,456	220	3.4%
Jul	6,648	6,462	186	2.9%	6,429	219	3.4%
Aug	6,647	6,459	188	2.9%	6,428	219	3.4%
Sep	6,690	6,498	192	3.0%	6,470	220	3.4%
Oct	6,772	6,638	134	2.0%	6,546	226	3.5%
Summer	6,688	6,539	149	2.3%	6,468	221	3.4%

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

	Total Division Use Per Meter						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	67.23	63.31	3.91	6.2%	60.98	6.25	10.2%
Jun	55.10	54.65	0.45	0.8%	50.12	4.98	9.9%
Jul	47.04	45.77	1.27	2.8%	42.99	4.05	9.4%
Aug	48.46	45.60	2.86	6.3%	44.25	4.21	9.5%
Sep	49.11	46.68	2.43	5.2%	44.76	4.34	9.7%
Oct	60.08	53.81	6.26	11.6%	54.73	5.34	9.8%
Summer	327.17	310.19	16.98	5.5%	297.98	29.17	9.8%

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
May-15	1,955	65,889	23,995	12,078	24,728	16,387	3,247	2,859	0	151,137
Jun-15	1,302	43,884	15,981	8,044	16,469	10,914	2,162	1,904	0	100,662
Jul-15	1,182	39,859	14,515	7,306	14,959	9,913	1,964	1,729	0	91,428
Aug-15	1,229	41,435	15,089	7,595	15,550	10,305	2,042	1,798	0	95,043
Sep-15	1,346	45,361	16,519	8,315	17,024	11,282	2,235	1,968	0	104,049
Oct-15	2,519	84,930	30,929	15,568	31,873	21,123	4,185	3,685	0	194,812
Summer	9,533	321,358	117,029	58,907	120,602	79,925	15,834	13,943	0	737,130
Total	28,935	1,777,608	900,936	143,377	767,284	194,490	92,801	36,333	0	3,941,764

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
May-15	1,955	65,889	30,835	17,243	47,334	42,994	32,199	126,435	94,525	459,409
Jun-15	1,302	43,884	22,401	12,891	37,683	35,882	29,331	117,869	88,703	389,947
Jul-15	1,182	39,859	20,483	11,812	34,680	33,124	27,221	109,535	82,461	360,358
Aug-15	1,229	41,435	21,277	12,268	35,999	34,373	28,232	113,585	85,507	373,904
Sep-15	1,346	45,361	22,916	13,145	38,163	36,162	29,309	117,527	88,392	392,321
Oct-15	2,519	84,930	38,658	21,404	57,415	51,184	36,896	143,308	106,799	543,113
Summer	9,533	321,358	156,569	88,764	251,274	233,720	183,187	728,260	546,386	2,519,052
Total	28,935	1,777,608	1,090,112	204,329	1,389,978	566,858	586,751	1,600,634	1,088,389	8,333,594

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-15	100%	100%	78%	70%	52%	38%	10%	2%	0%	33%
Jun-15	100%	100%	71%	62%	44%	30%	7%	2%	0%	26%
Jul-15	100%	100%	71%	62%	43%	30%	7%	2%	0%	25%
Aug-15	100%	100%	71%	62%	43%	30%	7%	2%	0%	25%
Sep-15	100%	100%	72%	63%	45%	31%	8%	2%	0%	27%
Oct-15	100%	100%	80%	73%	56%	41%	11%	3%	0%	36%
Summer	100%	100%	75%	66%	48%	34%	9%	2%	0%	29%
Total	100%	100%	83%	70%	55%	34%	16%	2%	0%	47%

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
May-15	2,154	103,615	47,377	9,698	39,931	16,980	4,347	2,760		226,863
Jun-15	2,427	58,985	20,521	10,129	23,325	13,130	3,024	1,706		133,248
Jul-15	730	36,782	10,917	9,425	7,883	11,301	1,752	2,820		81,610
Aug-15	1,376	33,792	9,611	10,064	12,539	12,702	2,313	1,752		84,149
Sep-15	1,352	34,615	9,508	10,300	12,393	12,829	785	2,441		84,225
Oct-15	1,494	53,568	19,094	9,292	24,531	12,982	3,613	2,463		127,036
Summer	9,533	321,358	117,029	58,907	120,602	79,925	15,834	13,943	0	737,130
Total	28,935	1,777,608	900,936	143,377	767,284	194,490	92,801	36,333	0	3,941,764

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
May-15	2,154	103,615	57,819	14,777	79,338	44,330	33,701	130,317	89,876	555,928
Jun-15	2,427	58,985	28,631	15,613	45,429	38,339	34,477	118,375	86,953	429,229
Jul-15	730	36,782	15,688	14,187	25,147	33,669	26,740	106,605	90,683	350,230
Aug-15	1,376	33,792	16,449	15,019	25,392	36,274	30,299	108,194	90,445	357,240
Sep-15	1,352	34,615	13,780	15,322	27,817	40,834	19,516	123,801	87,467	364,504
Oct-15	1,494	53,568	24,203	13,845	48,149	40,275	38,456	140,968	100,963	461,920
Summer	9,533	321,358	156,569	88,764	251,274	233,720	183,187	728,260	546,386	2,519,052
Total	28,935	1,777,608	1,090,112	204,329	1,389,978	566,858	586,751	1,600,634	1,088,389	8,333,594

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-15	100%	100%	82%	66%	50%	38%	13%	2%	0%	41%
Jun-15	100%	100%	72%	65%	51%	34%	9%	1%	0%	31%
Jul-15	100%	100%	70%	66%	31%	34%	7%	3%	0%	23%
Aug-15	100%	100%	58%	67%	49%	35%	8%	2%	0%	24%
Sep-15	100%	100%	69%	67%	45%	31%	4%	2%	0%	23%
Oct-15	100%	100%	79%	67%	51%	32%	9%	2%	0%	28%
Summer	100%	100%	75%	66%	48%	34%	9%	2%	0%	29%
Total	100%	100%	83%	70%	55%	34%	16%	2%	0%	47%

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern - New Hampshire City-Gate Sendout Requirement

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-14	795,914	0.02%	159	279,218	132,014	411,231	411,391	0.63%	2,608	413,999	34,804	448,803
Dec-14	1,056,614	0.02%	211	473,854	131,977	605,832	606,043	0.63%	3,842	609,885	81,127	691,012
Jan-15	1,281,064	0.02%	256	707,838	57,002	764,839	765,096	0.63%	4,850	769,946	122,398	892,344
Feb-15	1,105,051	0.02%	221	715,832	-76,448	639,384	639,605	0.63%	4,055	643,660	101,808	745,468
Mar-15	932,830	0.02%	187	621,488	-128,602	492,886	493,072	0.63%	3,126	496,198	50,623	546,821
Apr-15	643,069	0.02%	129	406,405	-115,943	290,461	290,590	0.63%	1,842	292,432		292,432
May-15	459,409	0.02%	92	226,863	-75,726	151,137	151,229	0.63%	959	152,188		152,188
Jun-15	389,947	0.02%	78	133,248	-32,586	100,662	100,740	0.63%	639	101,379		101,379
Jul-15	360,358	0.02%	72	81,610	9,818	91,428	91,500	0.63%	580	92,080		92,080
Aug-15	373,904	0.02%	75	84,149	10,894	95,043	95,117	0.63%	603	95,720		95,720
Sep-15	392,321	0.02%	78	84,225	19,824	104,049	104,127	0.63%	660	104,787		104,787
Oct-15	543,113	0.02%	109	127,036	67,776	194,812	194,921	0.63%	1,236	196,157		196,157
Winter	5,814,542	0.02%	1,163	3,204,634	0	3,204,634	3,205,797	0.63%	20,323	3,226,120	390,760	3,616,880
Summer	2,519,052	0.02%	504	737,130	0	737,130	737,634	0.63%	4,677	742,311	0	742,311
Annual	8,333,594	0.02%	1,667	3,941,764	0	3,941,764	3,943,431	0.63%	25,000	3,968,431	390,760	4,359,191

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
2	**Total Therms**								
3	Res Heat	409,365	396,159	401,430	409,365	396,159	409,365	4,812,004	2,421,843
4	Res General	12,137	11,746	11,902	12,137	11,746	12,137	142,670	71,805
5	G50 Low Annual-Low Winter	74,998	72,578	73,544	74,998	72,578	74,998	881,584	443,694
6	G40 Low Annual-High Winter	148,996	144,190	146,109	148,996	144,190	148,996	1,751,425	881,478
7	G51 Med Annual-Low Winter	101,757	98,474	99,785	101,757	98,474	101,757	1,196,133	602,004
8	G41 Med Annual-High Winter	153,546	148,593	150,571	153,546	148,593	153,546	1,804,907	908,395
9	G52 High Annual-Low Winter	17,751	17,179	17,407	17,751	17,179	17,751	208,663	105,018
10	G42 High Annual-High Winter	20,159	19,509	19,769	20,159	19,509	20,159	236,970	119,265
11	Total Firm Sales	938,709	908,429	920,518	938,709	908,429	938,709	11,034,355	5,553,503
12	**% of Total**								
13	Res Heat	43.61%	43.61%	43.61%	43.61%	43.61%	43.61%		
14	Res General	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%		
15	G50 Low Annual-Low Winter	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%		
16	G40 Low Annual-High Winter	15.87%	15.87%	15.87%	15.87%	15.87%	15.87%		
17	G51 Med Annual-Low Winter	10.84%	10.84%	10.84%	10.84%	10.84%	10.84%		
18	G41 Med Annual-High Winter	16.36%	16.36%	16.36%	16.36%	16.36%	16.36%		
19	G52 High Annual-Low Winter	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%		
20	G42 High Annual-High Winter	2.15%	2.15%	2.15%	2.15%	2.15%	2.15%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
23	TOTAL BASE COMMODITY Excld Hedging	$ 236,210	$ 212,911	$ 218,466	$ 217,165	$ 210,256	$ 259,177	$ 5,744,887	$ 1,354,185
24	Res Heat	$ 103,010	$ 92,849	$ 95,271	$ 94,704	$ 91,691	$ 113,025	$ 2,505,305	$ 590,550
25	Res General	$ 3,054	$ 2,753	$ 2,825	$ 2,808	$ 2,719	$ 3,351	$ 74,279	$ 17,509
26	G50 Low Annual-Low Winter	$ 18,872	$ 17,010	$ 17,454	$ 17,350	$ 16,798	$ 20,707	$ 458,985	$ 108,192
27	G40 Low Annual-High Winter	$ 37,492	$ 33,794	$ 34,676	$ 34,469	$ 33,373	$ 41,138	$ 911,855	$ 214,943
28	G51 Med Annual-Low Winter	$ 25,605	$ 23,080	$ 23,682	$ 23,541	$ 22,792	$ 28,095	$ 622,750	$ 146,795
29	G41 Med Annual-High Winter	$ 38,637	$ 34,826	$ 35,735	$ 35,522	$ 34,392	$ 42,394	$ 939,700	$ 221,506
30	G52 High Annual-Low Winter	$ 4,467	$ 4,026	$ 4,131	$ 4,107	$ 3,976	$ 4,901	$ 108,637	$ 25,608
31	G42 High Annual-High Winter	$ 5,073	$ 4,572	$ 4,692	$ 4,664	$ 4,515	$ 5,566	$ 123,375	$ 29,082
32									
33	Residential	$ 106,064	$ 95,602	$ 98,096	$ 97,512	$ 94,410	$ 116,376	$ 2,579,584	$ 608,060
34	SALES HLF CLASSES	$ 48,944	$ 44,116	$ 45,267	$ 44,998	$ 43,566	$ 53,703	$ 1,190,372	$ 280,595
35	SALES LLF CLASSES	$ 81,202	$ 73,193	$ 75,102	$ 74,655	$ 72,280	$ 89,098	$ 1,974,931	$ 465,531

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
37	TOTAL BASE HEDGING COMMODITY	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,818	$ -
38	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,537	$ -
39	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ 75	$ -
40	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 465	$ -
41	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 923	$ -
42	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 631	$ -
43	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 952	$ -
44	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 110	$ -
45	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 125	$ -
46									
47	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,612	$ -
48	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,206	$ -
49	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,000	$ -

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**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
51	**Total Therms**								
52	Res Heat	254,111	45,811	-	7,934	60,668	445,798	13,084,296	814,322
53	Res General	7,534	1,358	-	235	1,799	13,218	148,510	24,144
54	G50 Low Annual-Low Winter	46,557	8,391	-	1,453	11,114	81,676	561,256	149,190
55	G40 Low Annual-High Winter	92,493	16,669	-	2,887	22,079	162,264	7,314,309	296,393
56	G51 Med Annual-Low Winter	63,168	11,384	-	1,972	15,079	110,818	761,081	202,421
57	G41 Med Annual-High Winter	95,318	17,178	-	2,975	22,753	167,219	5,915,998	305,444
58	G52 High Annual-Low Winter	11,020	1,986	-	344	2,630	19,332	156,963	35,312
59	G42 High Annual-High Winter	12,514	2,255	-	391	2,987	21,954	696,856	40,102
60	Total Firm Sales	582,716	105,033	-	18,192	139,110	1,022,278	28,639,269	1,867,328
61	**% of Total**								
62	Res Heat	43.61%	43.62%	43.62%	43.62%	43.61%	43.61%		
63	Res General	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%		
64	G50 Low Annual-Low Winter	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%		
65	G40 Low Annual-High Winter	15.87%	15.87%	15.87%	15.87%	15.87%	15.87%		
66	G51 Med Annual-Low Winter	10.84%	10.84%	10.84%	10.84%	10.84%	10.84%		
67	G41 Med Annual-High Winter	16.36%	16.36%	16.36%	16.36%	16.36%	16.36%		
68	G52 High Annual-Low Winter	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%		
69	G42 High Annual-High Winter	2.15%	2.15%	2.15%	2.15%	2.15%	2.15%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
72	REMAINING COMMODITY Excld Hedging	$ 158,081	$ 36,040	$ 11,455	$ 15,683	$ 42,526	$ 291,993	$ 21,607,443	$ 555,778
73	Res Heat	$ 68,936	$ 15,719	$ 4,996	$ 6,840	$ 18,546	$ 127,333	$ 9,887,997	$ 242,371
74	Res General	$ 2,044	$ 466	$ 148	$ 203	$ 550	$ 3,775	$ 105,972	$ 7,186
75	G50 Low Annual-Low Winter	$ 12,630	$ 2,879	$ 915	$ 1,253	$ 3,397	$ 23,329	$ 376,154	$ 44,404
76	G40 Low Annual-High Winter	$ 25,092	$ 5,720	$ 1,818	$ 2,489	$ 6,750	$ 46,347	$ 5,594,243	$ 88,216
77	G51 Med Annual-Low Winter	$ 17,137	$ 3,906	$ 1,242	$ 1,700	$ 4,610	$ 31,653	$ 510,029	$ 60,247
78	G41 Med Annual-High Winter	$ 25,858	$ 5,894	$ 1,873	$ 2,565	$ 6,956	$ 47,763	$ 4,497,162	$ 90,909
79	G52 High Annual-Low Winter	$ 2,989	$ 681	$ 217	$ 297	$ 804	$ 5,522	$ 107,889	$ 10,510
80	G42 High Annual-High Winter	$ 3,395	$ 774	$ 246	$ 337	$ 913	$ 6,271	$ 527,997	$ 11,936
81									
82	Residential	$ 70,980	$ 16,185	$ 5,144	$ 7,043	$ 19,096	$ 131,108	$ 9,993,969	$ 249,557
83	SALES HLF CLASSES	$ 32,756	$ 7,467	$ 2,373	$ 3,249	$ 8,811	$ 60,504	$ 994,072	$ 115,160
84	SALES LLF CLASSES	$ 54,345	$ 12,388	$ 3,937	$ 5,391	$ 14,619	$ 100,381	$ 10,619,401	$ 191,061

85	**REMAINING COMMODITY HEDGING COSTS**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
86	TOTAL REMAINING COMMODITY HEDGING	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,117	$ -
87	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,129	$ -
88	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ 105	$ -
89	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 361	$ -
90	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,765	$ -
91	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 489	$ -
92	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,620	$ -
93	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 105	$ -
94	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 542	$ -
95								$ -	$ -
96	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,235	$ -
97	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 955	$ -
98	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,927	$ -

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

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	
51	**Total Therms**	
52	Res Heat	Schedule 10B, LN 68
53	Res General	Schedule 10B, LN 69
54	G50 Low Annual-Low Winter	Schedule 10B, LN 70
55	G40 Low Annual-High Winter	Schedule 10B, LN 71
56	G51 Med Annual-Low Winter	Schedule 10B, LN 72
57	G41 Med Annual-High Winter	Schedule 10B, LN 73
58	G52 High Annual-Low Winter	Schedule 10B, LN 74
59	G42 High Annual-High Winter	Schedule 10B, LN 75
60	Total Firm Sales	Sum LN 52 : LN 59
61	**% of Total**	
62	Res Heat	LN 52 / LN 60, Jul/Aug calculated together
63	Res General	LN 53 / LN 60, Jul/Aug calculated together
64	G50 Low Annual-Low Winter	LN 54 / LN 60, Jul/Aug calculated together
65	G40 Low Annual-High Winter	LN 55 / LN 60, Jul/Aug calculated together
66	G51 Med Annual-Low Winter	LN 56 / LN 60, Jul/Aug calculated together
67	G41 Med Annual-High Winter	LN 57 / LN 60, Jul/Aug calculated together
68	G52 High Annual-Low Winter	LN 58 / LN 60, Jul/Aug calculated together
69	G42 High Annual-High Winter	LN 59 / LN 60, Jul/Aug calculated together
70	Total Firm Sales	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**	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer
100	TOTAL COMMODITY Excld Hedging	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,352,330	$ 1,909,963
101	Res Heat	$ 171,946	$ 108,568	$ 100,267	$ 101,544	$ 110,237	$ 240,358	$ 12,393,302	$ 832,921
102	Res General	$ 5,098	$ 3,219	$ 2,973	$ 3,011	$ 3,268	$ 7,127	$ 180,251	$ 24,695
103	G50 Low Annual-Low Winter	$ 31,502	$ 19,889	$ 18,369	$ 18,603	$ 20,196	$ 44,036	$ 835,139	$ 152,596
104	G40 Low Annual-High Winter	$ 62,584	$ 39,514	$ 36,494	$ 36,958	$ 40,122	$ 87,485	$ 6,506,098	$ 303,158
105	G51 Med Annual-Low Winter	$ 42,742	$ 26,986	$ 24,923	$ 25,241	$ 27,402	$ 59,748	$ 1,132,779	$ 207,042
106	G41 Med Annual-High Winter	$ 64,495	$ 40,721	$ 37,608	$ 38,087	$ 41,348	$ 90,157	$ 5,436,862	$ 312,416
107	G52 High Annual-Low Winter	$ 7,456	$ 4,708	$ 4,348	$ 4,403	$ 4,780	$ 10,423	$ 216,527	$ 36,118
108	G42 High Annual-High Winter	$ 8,468	$ 5,346	$ 4,938	$ 5,001	$ 5,429	$ 11,837	$ 651,372	$ 41,018
109									
110	Residential	$ 177,044	$ 111,787	$ 103,240	$ 104,555	$ 113,506	$ 247,485	$ 12,573,553	$ 857,616
111	SALES HLF CLASSES	$ 81,700	$ 51,583	$ 47,641	$ 48,247	$ 52,377	$ 114,207	$ 2,184,445	$ 395,755
112	SALES LLF CLASSES	$ 135,548	$ 85,581	$ 79,040	$ 80,046	$ 86,899	$ 189,479	$ 12,594,332	$ 656,592

113	**TOTAL HEDGING COMMODITY COSTS**	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer
114	TOTAL HEDGING COMMODITY	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,935	$ -
115	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,667	$ -
116	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ 181	$ -
117	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 826	$ -
118	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,688	$ -
119	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,120	$ -
120	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,572	$ -
121	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 215	$ -
122	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 667	$ -
123									
124	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,847	$ -
125	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,161	$ -
126	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,927	$ -

127	TOTAL COMMODITY	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer
128	Res Heat	$ 171,946	$ 108,568	$ 100,267	$ 101,544	$ 110,237	$ 240,358	$ 12,405,969	$ 832,921
129	Res General	$ 5,098	$ 3,219	$ 2,973	$ 3,011	$ 3,268	$ 7,127	$ 180,432	$ 24,695
130	G50 Low Annual-Low Winter	$ 31,502	$ 19,889	$ 18,369	$ 18,603	$ 20,196	$ 44,036	$ 835,965	$ 152,596
131	G40 Low Annual-High Winter	$ 62,584	$ 39,514	$ 36,494	$ 36,958	$ 40,122	$ 87,485	$ 6,512,786	$ 303,158
132	G51 Med Annual-Low Winter	$ 42,742	$ 26,986	$ 24,923	$ 25,241	$ 27,402	$ 59,748	$ 1,133,899	$ 207,042
133	G41 Med Annual-High Winter	$ 64,495	$ 40,721	$ 37,608	$ 38,087	$ 41,348	$ 90,157	$ 5,442,434	$ 312,416
134	G52 High Annual-Low Winter	$ 7,456	$ 4,708	$ 4,348	$ 4,403	$ 4,780	$ 10,423	$ 216,742	$ 36,118
135	G42 High Annual-High Winter	$ 8,468	$ 5,346	$ 4,938	$ 5,001	$ 5,429	$ 11,837	$ 652,039	$ 41,018
136	Total Firm Sales	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 27,380,265	$ 1,909,963
137									
138	Residential	$ 177,044	$ 111,787	$ 103,240	$ 104,555	$ 113,506	$ 247,485	$ 12,586,400	$ 857,616
139	SALES HLF CLASSES	$ 81,700	$ 51,583	$ 47,641	$ 48,247	$ 52,377	$ 114,207	$ 2,186,606	$ 395,755
140	SALES LLF CLASSES	$ 135,548	$ 85,581	$ 79,040	$ 80,046	$ 86,899	$ 189,479	$ 12,607,259	$ 656,592
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								37.61%
144	SALES LLF CLASSES								62.39%

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	
100	TOTAL COMMODITY Excld Hedging	Schedule 1B, LN 41
101	Res Heat	LN 24 + LN 73
102	Res General	LN 25 + LN 74
103	G50 Low Annual-Low Winter	LN 26 + LN 75
104	G40 Low Annual-High Winter	LN 27 + LN 76
105	G51 Med Annual-Low Winter	LN 28 + LN 77
106	G41 Med Annual-High Winter	LN 29 + LN 78
107	G52 High Annual-Low Winter	LN 30 + LN 79
108	G42 High Annual-High Winter	LN 31 + LN 80
109		
110	Residential	LN 101 + LN 102
111	SALES HLF CLASSES	LN 103 + LN 105 + LN 107
112	SALES LLF CLASSES	LN 104 + LN 106 + LN 108
113	**TOTAL HEDGING COMMODITY COSTS**	
114	TOTAL HEDGING COMMODITY	Schedule 1B, LN 42
115	Res Heat	LN 38 + LN 87
116	Res General	LN 39 + LN 88
117	G50 Low Annual-Low Winter	LN 40 + LN 89
118	G40 Low Annual-High Winter	LN 41 + LN 90
119	G51 Med Annual-Low Winter	LN 42 + LN 91
120	G41 Med Annual-High Winter	LN 43 + LN 92
121	G52 High Annual-Low Winter	LN 44 + LN 93
122	G42 High Annual-High Winter	LN 45 + LN 94
123		
124	Residential	LN 115 + LN 116
125	SALES HLF CLASSES	LN 117 + LN 119 + LN 121
126	SALES LLF CLASSES	LN 118 + LN 120 + LN 122
127	**TOTAL COMMODITY**	
128	Res Heat	LN 101 + LN 115
129	Res General	LN 102 + LN 116
130	G50 Low Annual-Low Winter	LN 103 + LN 117
131	G40 Low Annual-High Winter	LN 104 + LN 118
132	G51 Med Annual-Low Winter	LN 105 + LN 119
133	G41 Med Annual-High Winter	LN 106 + LN 120
134	G52 High Annual-Low Winter	LN 107 + LN 121
135	G42 High Annual-High Winter	LN 108 + LN 122
136	Total Firm Sales	Sum LN 128 : LN 135
137		
138	Residential	LN 128 + LN 129
139	SALES HLF CLASSES	LN 130 + LN 132 + LN 134
140	SALES LLF CLASSES	LN 131 + LN 133 + LN 135
141		
142	% ALLOCATION BETWEEN SALES HLF AND LLF	
143	SALES HLF CLASSES	LN 139 / (LN 139 + LN 140)
144	SALES LLF CLASSES	LN 140 / (LN 139 + LN 140)

Schedule 11A

Northern Utilitiies, Inc.
New Hampshire Division
Schedule 11A
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Northern Utilities, Inc.
Normal Cold Winter Weather - Sales Service & Company Managed Sendout
Commodity Volumes by Supply Source (Dth)
November 2014 through April 2015

Description	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Season
Pipeline Supplies							
Tennessee Production	192,729	127,659	109,065	111,444	132,103	261,797	934,796
Chicago	0	0	0	0	0	424	424
Algonquin Receipts	0	0	0	0	0	0	0
TGP Zone 6	0	0	0	0	0	0	0
Niagara	51,704	3,373	0	0	8,554	65,777	129,408
Iroquois Receipts	0	0	0	0	0	0	0
PNGTS Receipts	0	0	0	0	0	2,045	2,045
PNGTS Delivered	0	0	0	0	0	0	0
Maritimes Delivered	0	0	0	0	0	7,351	7,351
Subtotal Pipeline	244,433	131,031	109,065	111,444	140,657	337,394	1,074,025
Underground Storage							
Tenn Zone 4 Spot	75,620	73,181	75,620	75,620	73,181	75,620	448,841
Tennessee Storage	0	0	0	0	0	0	0
Tennesse Storage Path	75,620	73,181	75,620	75,620	73,181	75,620	448,841
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
W10 Storage Path	0	0	0	0	0	0	0
Subtotal Storage	75,620	73,181	75,620	75,620	73,181	75,620	448,841
Peaking Supplies							
Peaking Contract 1	0	0	0	0	0	0	0
Peaking Contract 2	0	0	0	0	0	0	0
LNG	2,170	2,100	2,170	2,170	2,100	2,170	12,880
Subtotal Peaking	2,170	2,100	2,170	2,170	2,100	2,170	12,880
Total Delivered (Dth)	322,223	206,312	186,855	189,234	215,938	415,184	1,535,746

Schedule 11B

Provided in the Winter 2014-15 Cost-of-Gas Filing

Schedule 11C

Northern Utilities, Inc.
Normal Winter Weather - Sales Service & Company Managed Sendout
Capacity Utilization by Supply Source
November 2014 through April 2015

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	934,796	2,412,056	39%
Chicago and Iroquois	1,011,699	1,183,856	85%
Algonquin Receipts	0	230,184	0%
TGP Zone 6	0	0	
Niagara	129,408	428,168	30%
PNGTS Receipts	2,045	201,664	1%
PNGTS Delivered	0	1,128,574	0%
Maritimes Delivered	7,351	7,474	98%
Subtotal Pipeline	2,085,299	5,591,976	37%
Underground Storage			
Tenn Zone 4 Spot	448,841	485,443	92%
Tennessee Storage	0		
Tennesse Storage Path	448,841	486,443	92%
W10 AMA Spot	0		
Washington 10 Storage	0		
W10 Storage Path	0	0	
Subtotal Storage	448,841	486,443	92%
Peaking Supplies			
Peaking Contract 1	0	298,950	0%
Peaking Contract 2	0	299,355	0%
LNG	12,880	1,840,000	1%
Subtotal Peaking	12,880	2,438,305	1%
Total Delivered (Dth)	1,535,746	8,516,724	18%

Schedule 11D & Schedule 11E

Provided in the Winter 2014-15 Cost-of-Gas Filing

Schedule 12

Provided in the Winter 2014-15 Cost-of-Gas Filing

Schedule 13

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2014 through October 2015

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	900,936	42%	83%
G50	143,377	7%	70%
G41	767,284	36%	55%
G51	194,490	9%	34%
G42	92,801	4%	16%
G52	36,333	2%	2%
Special Contracts	-	0%	0%
Total C&I	2,135,221	100%	33%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	189,176	4%	17%
T50	60,953	1%	30%
T41	622,694	14%	45%
T51	372,367	8%	66%
T42	493,950	11%	84%
T52	1,564,301	36%	98%
Special Contracts	1,088,389	25%	100%
Total C&I	4,391,830	100%	67%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	1,090,112	17%
G/T50	204,329	3%
G/T41	1,389,978	21%
G/T51	566,858	9%
G/T42	586,751	9%
G/T52	1,600,634	25%
Special Contracts	1,088,389	17%
Total C&I	6,527,051	100%

Schedule 14

Provided in the Winter 2014-15 Cost-of-Gas Filing

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER SEASON BALANCE
November 2013 - October 2014

	AMOUNT	
Summer Season Beg. Balance	$ 401,941	SCHEDULE 2
Less: Reported Collections	$ (4,763,727)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$ 3,765,748	SCHEDULE 4
Add: Interest	$ (702)	SCHEDULE 2
October 31, 2014 Adjustment	$ 125,942	SCHEDULE 2
Summer Season Ending Balance	$ (470,799)	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER SEASON ACCOUNTS
November 2013 - October 2014
Acct 191.10

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total
SUMMER SEASON													
Summer Season Account Beginning Balance	$ 394,545												
Reconciliation Adjustment 1*	$ 7,396												
Adjusted Seasonal Balance	$ 401,941	$ 149,484	$ 146,449	$ 146,280	$ 146,786	$ 147,084	$ 147,492	$ (205,099)	$ (180,772)	$ (227,448)	$ (164,887)	$ (267,588)	$ 401,941
Plus: Cost of Firm Gas (Schedule 4)	$ (8,270)	$ (3,115)	$ -	$ -	$ -	$ -	$ 735,157	$ 570,452	$ 573,410	$ 560,148	$ 589,798	$ 748,168	$ 3,765,748
Less: Reported Collections (Schedule 3)	$ (244,933)	$ (320)	$ (565)	$ 110	$ (100)	$ 10	$(1,087,670)	$ (545,603)	$ (619,534)	$ (497,057)	$ (691,914)	$ (1,076,152)	$ (4,763,727)
Summer Season Account Ending Balance	$ 148,738	$ 146,049	$ 145,884	$ 146,390	$ 146,686	$ 147,093	$ (205,021)	$ (180,250)	$ (226,896)	$ (164,356)	$ (267,003)	$ (595,572)	$ (596,039)
Month's Average Balance	$ 275,339	$ 147,766	$ 146,167	$ 146,335	$ 146,736	$ 147,089	$ (28,765)	$ (192,675)	$ (203,834)	$ (195,902)	$ (215,945)	$ (431,580)	
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	$ 746	$ 400	$ 396	$ 396	$ 397	$ 398	$ (78)	$ (522)	$ (552)	$ (531)	$ (585)	$ (1,169)	$ (702)
Reconciliation Adjustment 2*												$ 125,942	$ 125,942
Summer Season Account Ending Balance w/int	$ 149,484	$ 146,449	$ 146,280	$ 146,786	$ 147,084	$ 147,492	$ (205,099)	$ (180,772)	$ (227,448)	$ (164,887)	$ (267,588)	$ (470,799)	$ (470,799)

*Reconciliation Adjustment 1: Reflects an adjustment of $7,355.69 for miscelleneous overhead expense allowed in most recent base rate case proceeding -Docket No. DG13-086 - plus $39.94 of interest.

*Reconciliation Adjustment 2: Outstanding balance of PNGTS refund transferered from supplier refund account (see Attachment D).

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2013 - October 2014

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total
Accrued Revenue	$ (648,211)	$ -	$ -	$ -	$ -	$ -	$ 497,069	$ (292,469)	$ 47,903	$ 11,611	$ 153,111	$ 245,965	$ 14,980
Billed Revenue	$ 893,143	$ 320	$ 565	$ (110)	$ 100	$ (10)	$ 590,600	$ 838,071	$ 571,631	$ 485,446	$ 538,803	$ 830,186	$ 4,748,747
Calendarized Revenue	$ 244,933	$ 320	$ 565	$ (110)	$ 100	$ (10)	$ 1,087,670	$ 545,603	$ 619,534	$ 497,057	$ 691,914	$ 1,076,152	$ 4,763,727

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2013 - October 2014

Commodity 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**	**Total Off Peak**
Barclays Bank	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,369	$ 77,185	$ 74,620	$ 67,230	$ 66,524	**$ 368,928**
Chesapeak Energy Marketing	$ 182,059	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,092	$ 38,565	$ -	**$ 264,716**
DTE Energy Trading	$ 129,369	$ -	$ -	$ -	$ -	$ -	$ -	$ 159,887	$ 60,229	$ -	$ -	$ -	**$ 349,485**
Emera Energy Services	$ 144,909	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 144,909**
Reposl Energy North American	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,073	$ -	$ -	$ -	**$ 4,073**
Shell Energy North America	$ 159,507	$ -	$ -	$ -	$ -	$ -	$ -	$ 153,039	$ 82,689	$ 79,851	$ 71,681	$ 133,688	**$ 680,456**
Southwestern Energy Services	$ 14,177	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 14,177**
Tenaska Marketing Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 192,736	$ 180,232	$ 172,134	$ 149,032	$ 134,206	**$ 828,339**
Subtotal - Commodity Supply	$ 630,021	$ -	$ -	$ -	$ -	$ -	$ -	$ 589,031	$ 404,408	$ 370,698	$ 326,507	$ 334,418	**$ 2,655,083**
REDACTED													
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 77	$ 38	$ 36	$ 36	$ 52	$ 86	**$ 326**
Portland	$ 35	$ -	$ -	$ -	$ -	$ -	$ -	$ 20	$ 19	$ 19	$ 20	$ 19	**$ 132**
Tennessee	$ 11,677	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,770	$ 6,650	$ 6,801	$ 6,923	$ 8,509	**$ 51,330**
Subtotal - Commodity Transportation	$ 11,712	$ -	$ -	$ -	$ -	$ -	$ 77	$ 10,828	$ 6,705	$ 6,857	$ 6,995	$ 8,613	**$ 51,787**
[redacted]	$ -	$ (3,115)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (3,115)**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal - Contractor Credits*	$ -	$ (3,115)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (3,115)**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 599,826	$ 411,077	$ 370,736	$ 333,469	$ 345,181	$ 551,975	**$ 2,612,264**
Commodity Cost Reversals	$ (643,248)	$ -	$ -	$ -	$ -	$ -	$ -	$ (599,826)	$ (411,077)	$ (370,736)	$ (333,469)	$ (345,181)	**$ (2,703,537)**
Subtotal - Estimates	$ (643,248)	$ -	$ -	$ -	$ -	$ -	$ 599,826	$ (188,749)	$ (40,341)	$ (37,267)	$ 11,712	$ 206,794	**$ (91,273)**
Subtotal - Supply	$ (1,515)	$ (3,115)	$ -	$ -	$ -	$ -	$ 599,903	$ 411,110	$ 370,772	$ 340,288	$ 345,215	$ 549,825	**$ 2,612,482**
Withdrawal - Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,051	$ 5	$ 8,275	$ 8,166	$ 29,410	$ 4,159	**$ 52,066**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (65,600)	$ (55,286)	$ (20,878)	$ (3,694)	$ 14,985	$ 41,510	**$ (88,962)**
Off System Sales	$ (101,471)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (101,471)**
Net OBA Adjustment	$ (85)	$ -	$ -	$ -	$ -	$ -	$ (6,126)	$ 5,307	$ 10,141	$ 7,996	$ 2,328	$ 1,376	**$ 20,936**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,493	$ 18,909	$ 14,560	$ 14,304	$ 10,872	$ 10,846	**$ 89,984**
Transportation Charges	$ (6,486)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,001)	$ (6,890)	$ 2,303	$ -	$ (24,488)	**$ (37,563)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,875	$ 21,848	$ 26,869	$ 20,224	$ 16,428	$ 0	**$ 99,244**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal - Other Commodity	$ (108,043)	$ -	$ -	$ -	$ -	$ -	$ (35,307)	$ (11,218)	$ 32,078	$ 49,300	$ 74,023	$ 33,402	**$ 34,234**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,620)	**$ (5,620)**
Sales for Resale Reversals	$ 101,288	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 101,288**
Subtotal - Estimates	$ 101,288	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,620)	**$ 95,668**
Total Commodity Costs	**$ (8,270)**	**$ (3,115)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 564,596**	**$ 399,891**	**$ 402,850**	**$ 389,587**	**$ 419,237**	**$ 577,607**	**$ 2,742,384**
Demand Costs													
Forecasted Summer Demand Costs (DG 13-257)	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,274	$ 154,274	$ 154,274	$ 154,274	$ 154,274	$ 154,274	**$ 925,646**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,286	$ 16,286	$ 16,286	$ 16,286	$ 16,286	$ 16,286	**$ 97,718**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 170,561**	**$ 170,561**	**$ 170,561**	**$ 170,561**	**$ 170,561**	**$ 170,561**	**$ 1,023,364**
Total Gas Costs	**$ (8,270)**	**$ (3,115)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 735,157**	**$ 570,452**	**$ 573,410**	**$ 560,148**	**$ 589,798**	**$ 748,168**	**$ 3,765,748**

*: Contractor Credits reflect payments to Northern for gas loss due to a line rupture.

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2013 - October 2014

REDACTED

Commodity Volumes:	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Total Off Peak**
Barclays Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake Energy Marketing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE Energy Trading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reposl Energy North American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Shell Energy North America	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southwestern Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tenaska Marketing Ventures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Contractor Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sales for Resale Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sales for Resale Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

FORM III
Schedule 4
Page 3 of 9

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2013 - October 2014

REDACTED

Commodity Costs per Unit:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total Off Peak
Barclays Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeak Energy Marketing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE Energy Trading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reposl Energy North American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Shell Energy North America	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southwestern Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tenaska Marketing Ventures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Contractor Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN UTILITIES, INC. - MAINE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2013 - October 2014

REDACTED

Commodity 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**	**Total Off Peak**
Barclays Bank	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 88,526	$ 83,885	$ 85,030	$ 74,068	$ 74,686	**$ 406,195**
Chesapeak Energy Marketing	$ 186,630	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,243	$ 42,488	$ -	**$ 279,361**
DTE Energy Trading	$ 132,618	$ -	$ -	$ -	$ -	$ -	$ -	$ 169,777	$ 65,457	$ -	$ -	$ -	**$ 367,852**
Emera Energy Services	$ 148,547	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 148,547**
Reposl Energy North American	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,427	$ -	$ -	$ -	**$ 4,427**
Shell Energy North America	$ 163,513	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,505	$ 89,868	$ 90,990	$ 78,973	$ 150,091	**$ 735,939**
Southwestern Energy Services	$ 14,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 14,533**
Tenaska Marketing Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,658	$ 195,878	$ 196,146	$ 164,192	$ 150,671	**$ 911,545**
Subtotal - Commodity Supply	$ 645,842	$ -	$ -	$ -	$ -	$ -	$ -	$ 625,466	$ 439,515	$ 422,409	$ 359,721	$ 375,448	**$ 2,868,400**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 82	$ 41	$ 41	$ 40	$ 59	$ 99	**$ 362**
Portland	$ 36	$ -	$ -	$ -	$ -	$ -	$ -	$ 21	$ 21	$ 22	$ 22	$ 21	**$ 142**
Tennessee	$ 11,970	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,436	$ 7,227	$ 7,750	$ 7,628	$ 9,552	**$ 55,563**
Subtotal - Commodity Transportation	$ 12,006	$ -	$ -	$ -	$ -	$ -	$ 82	$ 11,498	$ 7,289	$ 7,812	$ 7,708	$ 9,672	**$ 56,068**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (522)	$ -	**$ (522)**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (128)	**$ (128)**
Subtotal - Contractor Credits*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (522)	$ (128)	**$ (650)**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 636,928	$ 446,763	$ 422,453	$ 367,391	$ 387,533	$ 635,579	**$ 2,896,647**
Commodity Cost Reversals	$ (659,401)	$ -	$ -	$ -	$ -	$ -	$ -	$ (636,928)	$(446,763)	$(422,453)	$(367,391)	$ (387,533)	**$ (2,920,469)**
Subtotal - Estimates	$ (659,401)	$ -	$ -	$ -	$ -	$ -	$ 636,928	$ (190,165)	$ (24,310)	$ (55,062)	$ 20,142	$ 248,046	**$ (23,822)**
Subtotal - Supply	$ (1,554)	$ -	$ -	$ -	$ -	$ -	$ 637,010	$ 446,799	$ 422,494	$ 375,159	$ 387,049	$ 633,039	**$ 2,899,996**
Withdrawal - Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,178	$ 5	$ 9,430	$ 8,998	$ 33,018	$ 4,787	**$ 58,415**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (69,658)	$ (59,733)	$ (23,711)	$ (4,069)	$ 16,824	$ 51,873	**$ (88,475)**
Off System Sales	$ (104,019)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (104,019)**
Net OBA Adjustment	$ (88)	$ -	$ -	$ -	$ -	$ -	$ (6,505)	$ 5,768	$ 11,556	$ 8,809	$ 2,613	$ 1,584	**$ 23,737**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,761	$ 20,550	$ 16,591	$ 15,759	$ 12,206	$ 12,488	**$ 99,356**
Transportation Charges	$ (6,649)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,125)	$ (7,488)	$ 2,624	$ -	$ (27,493)	**$ (41,131)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,733	$ 23,744	$ 30,617	$ 22,281	$ 18,443	$ 0	**$ 109,820**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 661	$ 445	$ 584	$ 550	$ 539	$ 411	**$ 3,190**
Subtotal - Other Commodity	$ (110,756)	$ -	$ -	$ -	$ -	$ -	$ (36,831)	$ (11,346)	$ 37,579	$ 54,952	$ 83,643	$ 43,651	**$ 60,893**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,472)	**(6,472)**
Sales for Resale Reversals	$ 103,831	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**103,831**
Subtotal - Estimates	$ 103,831	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,472)	**$ 97,359**
Total Commodity Costs	**$ (8,478)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 600,180**	**$ 435,453**	**$ 460,073**	**$ 430,110**	**$ 470,692**	**$ 670,218**	**$ 3,058,247**
Demand Costs													
Assigned Summer Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 191,995	$ 191,995	$ 191,995	$ 191,995	$ 191,995	$ 191,995	$ 1,151,970
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,618	$ 4,618	$ 4,618	$ 4,618	$ 4,618	$ 4,618	$ 27,705
PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 344	$ 76	$ -	$ 6	$ 139	$ 723	$ 1,288
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 196,957**	**$ 196,689**	**$ 196,613**	**$ 196,619**	**$ 196,752**	**$ 197,335**	**$ 1,180,963**
Total Gas Costs	**$ (8,478)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 797,136**	**$ 632,142**	**$ 656,686**	**$ 626,729**	**$ 667,443**	**$ 867,553**	**$ 4,239,210**

*: Contractor Credits reflect payments to Northern for gas loss due to a line rupture.

FORM III
Schedule 4
Page 5 of 9

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2013 - October 2014

REDACTED

Commodity Volumes:	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Total Off Peak**
Barclays Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake Energy Marketing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE Energy Trading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reposl Energy North American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Shell Energy North America	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southwestern Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tenaska Marketing Ventures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Contractor Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2013 - October 2014

REDACTED

Commodity Costs per Unit:	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Total Off Peak**
Barclays Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeak Energy Marketing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE Energy Trading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reposl Energy North American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Shell Energy North America	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southwestern Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tenaska Marketing Ventures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Contractor Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2013 - October 2014

Commodity 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**	**Total Off Peak**
Barclays Bank	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 171,895	$ 161,070	$ 159,650	$ 141,298	$ 141,210	**$ 775,123**
Chesapeak Energy Marketing	$ 368,689	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 94,335	$ 81,052	$ -	**$ 544,077**
DTE Energy Trading	$ 261,987	$ -	$ -	$ -	$ -	$ -	$ -	$ 329,664	$ 125,686	$ -	$ -	$ -	**$ 717,337**
Emera Energy Services	$ 293,456	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 293,456**
Reposl Energy North American	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,500	$ -	$ -	$ -	**$ 8,500**
Shell Energy North America	$ 323,020	$ -	$ -	$ -	$ -	$ -	$ -	$ 315,544	$ 172,557	$ 170,841	$ 150,654	$ 283,779	**$ 1,416,396**
Southwestern Energy Services	$ 28,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 28,710**
Tenaska Marketing Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397,394	$ 376,110	$ 368,280	$ 313,224	$ 284,877	**$ 1,739,885**
Subtotal - Commodity Supply	$ 1,275,862	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,214,497	$ 843,923	$ 793,106	$ 686,228	$ 709,866	$ 5,523,483
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 160	$ 79	$ 77	$ 77	$ 111	$ 185	**$ 688**
Portland	$ 71	$ -	$ -	$ -	$ -	$ -	$ -	$ 41	$ 40	$ 41	$ 41	$ 40	**$ 274**
Tennessee	$ 23,647	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,205	$ 13,877	$ 14,551	$ 14,551	$ 18,061	**$ 106,893**
Subtotal - Commodity Transportation	$ 23,718	$ -	$ -	$ -	$ -	$ -	$ 160	$ 22,326	$ 13,994	$ 14,669	$ 14,703	$ 18,286	**$ 107,855**
REDACTED													
[redacted]	$ -	$ (3,115)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (3,115)**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (522)	$ -	**$ (522)**
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (128)	**$ (128)**
Subtotal - Contractor Credits*	$ -	$ (3,115)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (522)	$ (128)	**$ (3,765)**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,236,754	$ 857,840	$ 793,189	$ 700,860	$ 732,714	$ 1,187,554	**$ 5,508,911**
Commodity Cost Reversals	$ (1,302,649)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,236,754)	$ (857,840)	$ (793,189)	$ (700,860)	$ (732,714)	**$ (5,624,006)**
Subtotal - Estimates	$ (1,302,649)	$ -	$ -	$ -	$ -	$ -	$ 1,236,754	$ (378,914)	$ (64,651)	$ (92,329)	$ 31,854	$ 454,840	**$ (115,095)**
Subtotal - Supply	$ (3,069)	$ (3,115)	$ -	$ -	$ -	$ -	$ 1,236,914	$ 857,909	$ 793,266	$ 715,446	$ 732,263	$ 1,182,864	**$ 5,512,478**
Withdrawal - Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,229	$ 10	$ 17,705	$ 17,164	$ 62,427	$ 8,946	**$ 110,482**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (135,259)	$ (115,019)	$ (44,589)	$ (7,763)	$ 31,809	$ 93,382	**$ (177,438)**
Off System Sales	$ (205,490)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (205,490)**
Net OBA Adjustment	$ (173)	$ -	$ -	$ -	$ -	$ -	$ (12,632)	$ 11,076	$ 21,697	$ 16,804	$ 4,941	$ 2,960	**$ 44,673**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,254	$ 39,459	$ 31,150	$ 30,064	$ 23,079	$ 23,334	**$ 189,340**
Transportation Charges	$ (13,135)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,126)	$ (14,378)	$ 4,927	$ -	$ (51,981)	**$ (78,693)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,609	$ 45,592	$ 57,487	$ 42,505	$ 34,871	$ 0	**$ 209,064**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 661	$ 445	$ 584	$ 550	$ 539	$ 411	**$ 3,190**
Subtotal - Other Commodity	$ (218,798)	$ -	$ -	$ -	$ -	$ -	$ (72,138)	$ (22,564)	$ 69,657	$ 104,251	$ 157,666	$ 77,053	$ 95,127
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,092)	$ (12,092)
Sales for Resale Reversals	$ 205,119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,119
Subtotal - Estimates	$ 205,119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,092)	**$ 193,027**
Total Commodity Costs	**$ (16,748)**	**$ (3,115)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,164,776**	**$ 835,345**	**$ 862,923**	**$ 819,698**	**$ 889,929**	**$ 1,247,825**	**$ 5,800,632**
Demand Costs													
Assigned Summer Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 346,269	$ 346,269	$ 346,269	$ 346,269	$ 346,269	$ 346,269	$ 2,077,616
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,904	$ 20,904	$ 20,904	$ 20,904	$ 20,904	$ 20,904	$ 125,423
PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 344	$ 76	$ -	$ 6	$ 139	$ 723	$ 1,288
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 367,517**	**$ 367,249**	**$ 367,173**	**$ 367,179**	**$ 367,312**	**$ 367,896**	**$ 2,204,326**
Total Costs	**$ (16,748)**	**$ (3,115)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,532,293**	**$ 1,202,594**	**$ 1,230,096**	**$ 1,186,877**	**$ 1,257,241**	**$ 1,615,720**	**$ 8,004,958**

*: Contractor Credits reflect payments to Northern for gas loss due to a line rupture.

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2013 - October 2014

REDACTED

Commodity Volumes:	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Total Off Peak**
Barclays Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake Energy Marketing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE Energy Trading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reposl Energy North American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Shell Energy North America	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southwestern Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tenaska Marketing Ventures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Contractor Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2014 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2013 - October 2014

Commodity Costs per Unit:	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Total Off Peak**
Barclays Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake Energy Marketing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE Energy Trading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reposl Energy North American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Shell Energy North America	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southwestern Energy Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tenaska Marketing Ventures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
REDACTED [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Contractor Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2013 - October 2014

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	Total
Throughput IN													
BTU Factor	1.028	1.03	1.037	1.033	1.03	1.031	1.033	1.037	1.033	1.031	1.026	1.026	
GST Meter Throughput (MCF)	721,172	1,011,103	1,101,964	945,004	960,102	585,094	400,652	351,228	308,511	314,116	336,173	439,537	7,474,656
Salem Meter (MCF)	43,060	66,847	78,114	66,670	63,835	30,968	16,158	11,799	10,795	11,573	13,023	20,959	433,801
GST Meter Throughpurt (DTH)	741,365	1,041,436	1,142,737	976,189	988,905	603,232	413,874	364,223	318,692	323,854	344,913	450,921	7,710,341
Salem Meter (DTH)	44,266	68,852	81,004	68,870	65,750	31,928	16,691	12,236	11,151	11,932	13,362	21,502	447,544
LNG/Propane													-
Total Throughput	785,630	1,110,289	1,223,741	1,045,059	1,054,655	635,160	430,565	376,459	329,843	335,785	358,275	472,423	8,157,884
Throughput OUT													
Residential Gas													
Charged	129,897	244,069	333,579	330,531	301,458	210,141	109,776	56,260	37,768	32,977	35,829	58,729	1,881,014
Uncharged Current	126,803	214,603	223,191	146,825	164,281	123,599	31,549	10,289	18,082	19,158	40,093	63,900	1,182,374
Uncharged Prior	(86,052)	(126,803)	(214,603)	(223,191)	(146,825)	(164,281)	(123,599)	(31,549)	(10,289)	(18,082)	(19,158)	(40,093)	(1,204,526)
Total Residential Gas	**170,648**	**331,870**	**342,166**	**254,166**	**318,914**	**169,459**	**17,726**	**35,000**	**45,561**	**34,053**	**56,764**	**82,536**	1,858,862
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	145,309	256,463	374,634	364,492	348,407	229,795	119,718	64,200	48,976	45,264	50,884	73,226	2,121,368
Uncharged Current	124,134	220,474	245,771	163,453	194,330	139,537	41,422	20,556	23,635	24,413	41,505	61,255	1,300,487
Uncharged Prior	(76,149)	(124,134)	(220,474)	(245,771)	(163,453)	(194,330)	(139,537)	(41,422)	(20,556)	(23,635)	(24,413)	(41,505)	(1,315,381)
Total C/I Gas	**193,294**	**352,803**	**399,931**	**282,174**	**379,284**	**175,002**	**21,603**	**43,334**	**52,056**	**46,042**	**67,976**	**92,976**	2,106,474
Transportation													
Charged	369,979	427,221	485,858	468,509	452,495	366,768	299,662	293,963	246,796	249,278	252,427	283,973	4,196,929
Uncharged Current	208,354	281,276	258,021	176,282	207,706	176,984	99,242	97,091	75,832	84,798	118,785	128,845	1,913,217
Uncharged Prior	(215,133)	(208,354)	(281,276)	(258,021)	(176,282)	(207,706)	(176,984)	(99,242)	(97,091)	(75,832)	(84,798)	(118,785)	(1,999,504)
Total Transportation	**363,200**	**500,143**	**462,603**	**386,770**	**483,919**	**336,046**	**221,920**	**291,812**	**225,537**	**258,244**	**286,414**	**294,033**	**4,110,641**
Company Use	**118**	**225**	**318**	**338**	**304**	**236**	**117**	**54**	**110**	**150**	**108**	**78**	**2,156**
Total Throughput OUT	**727,260**	**1,185,041**	**1,205,019**	**923,448**	**1,182,420**	**680,742**	**261,366**	**370,200**	**323,263**	**338,489**	**411,262**	**469,623**	**8,078,134**
Total Throughput IN	**785,630**	**1,110,289**	**1,223,741**	**1,045,059**	**1,054,655**	**635,160**	**430,565**	**376,459**	**329,843**	**335,785**	**358,275**	**472,423**	**8,157,884**
Difference IN/OUT	58,370	(74,752)	18,722	121,611	(127,765)	(45,582)	169,199	6,259	6,580	(2,704)	(52,987)	2,800	79,751
%													0.98%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2013 - October 2014

SUMMER SEASON - Acct 182.21

	BEGINNING BALANCE	WORKING CAP ALLOWANCE (1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2013*	$ 867	(7)	0.0824%	(248)	(255)	612	739	3.25%	2	614
December	$ 614	(3)	0.0824%	(0)	(3)	611	612	3.25%	2	613
January 2014	$ 613	0	0.0824%	(1)	(1)	612	612	3.25%	2	614
February	$ 614	0	0.0824%	0	0	614	614	3.25%	2	615
March	$ 615	0	0.0824%	(0)	(0)	615	615	3.25%	2	617
April	$ 617	0	0.0824%	0	0	617	617	3.25%	2	619
May	$ 619	606	0.0824%	(936)	(330)	288	453	3.25%	1	289
June	$ 289	470	0.0824%	(465)	5	295	292	3.25%	1	295
July	$ 295	472	0.0824%	(554)	(82)	214	255	3.25%	1	215
August	$ 215	462	0.0824%	(482)	(21)	194	204	3.25%	1	195
September	$ 195	486	0.0824%	(665)	(179)	16	105	3.25%	0	16
October	$ 16	616	0.0824%	(1,019)	(402)	(386)	(185)	3.25%	(1)	(387)

*: Reflects last year's balance of $861 plus an adjustment of $6. Adjustment pertains to miscelleneous overhead expense allowed in most recent base rate case proceeding, Docket No. DG13-086. This expense boosts demand costs which impact working capital expenses.

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 1 of 9, and multiplying by (9.25/365)*Interest Rate.

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SUMMER SEASON BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2013 - October 2014

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2013	($3,098)	1,987		11	1,999	(1,099)	(2,098)	3.25%	(6)	(1,105)
December	($1,105)	3,234		0	3,234	2,129	512	3.25%	1	2,131
January 2014	$2,131	3,106		0	3,106	5,236	3,683	3.25%	10	5,246
February	$5,246	1,334		1	1,335	6,581	5,914	3.25%	16	6,597
March	$6,597	1,040		0	1,040	7,637	7,117	3.25%	19	7,656
April	$7,656	1,308		-	1,308	8,964	8,310	3.25%	23	8,986
May	$8,986	677		(4,711)	(4,033)	4,953	6,970	3.25%	19	4,972
June	$4,972	1,234		(2,344)	(1,111)	3,861	4,416	3.25%	12	3,873
July	$3,873	2,979		(2,931)	49	3,922	3,897	3.25%	11	3,932
August	$3,932	3,542		(2,403)	1,139	5,072	4,502	3.25%	12	5,084
September	$5,084	2,990		(3,337)	(347)	4,736	4,910	3.25%	13	4,750
October	$4,750	1,291		(5,127)	(3,837)	913	2,831	3.25%	8	921

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2014

	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	TOTAL
Forecast Calendar Month Sales	132,761	94,401	82,392	86,073	94,942	166,111	656,679
Actual Sales	229,494	120,460	86,744	78,241	86,713	131,955	733,607
Difference	96,733	26,059	4,352	(7,832)	(8,229)	(34,155)	76,928
Add:	132,761	94,401	82,392	86,073	94,942	166,111	
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	132,761	94,401	82,392	86,073	94,942	166,111	656,679
Actual Sales	229,494	120,460	86,744	78,241	86,713	131,955	733,607
Weather Variance	(96,733)	(26,059)	(4,352)	7,832	8,229	34,155	(76,928)
Total Variance Excluding Weather (excl weather effect)	-	-	-	-	-	-	-
Variance-difference due to meter count							(25,106)
-difference in load pattern							102,034
SALES							76,928

Attachment C
Page 2 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2014

	NORMAL MMBtu			METERS		
	2014 Forecast	2014 Actual	Difference	2014 Forecast	2014 Actual	Difference
Res Heat	305,313	319,868	14,554	136,877	133,324	(3,553)
Res General	11,419	11,471	52	9,179	9,481	302
Total Res	316,732	331,339	14,606	146,056	142,805	(3,251)
G-40	97,967	101,592	3,625	26,635	25,022	(1,613)
G-50	61,970	67,492	5,522	4,686	4,729	43
G-41	84,283	124,348	40,065	2,240	2,442	202
G-51	74,966	82,783	7,817	882	790	(92)
G-42	6,349	11,238	4,889	60	49	(11)
G-52	14,412	14,816	404	48	12	(36)
Total C & I	339,947	402,269	62,322	34,551	33,044	(1,507)
Total Company	656,679	733,607	76,928	180,607	175,849	(4,758)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2014 Forecast	2014 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.23	2.40	0.17	(7,925)	22,480	14,554	4.77%
Res General	1.24	1.21	(0.03)	376	(324)	52	0.46%
Total Res	3.47	3.61	0.13	(7,550)	22,156	14,606	4.61%
G-40	3.68	4.06	0.38	(5,933)	9,558	3,625	3.70%
G-50	13.22	14.27	1.05	569	4,953	5,522	8.91%
G-41	37.63	50.92	13.29	7,601	32,464	40,065	47.54%
G-51	85.00	104.79	19.79	(7,820)	15,636	7,817	10.43%
G-42	105.82	229.35	123.53	(1,164)	6,053	4,889	77.00%
G-52	300.25	1,234.69	934.44	(10,809)	11,213	404	2.81%
Total C & I	9.84	12.17	2.33	(17,556)	79,878	62,322	18.33%
Total Company	3.64	4.17	0.54	(25,106)	102,034	76,928	11.71%

Attachment D

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 ANNUAL RECONCILIATION
SUPPLIER REFUNDS
Period Ending October 31, 2014

ANNUAL DEMAND - Acct 242.90.10

	BEGINNING BALANCE	REFUND COLLECTIONS	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C = A + B	D = (A + C) / 2	E	F = D * (E / 12)	G = C + F
November 2013	$ (501,015)	24,061	(476,953)	(488,984)	3.25%	(1,324)	(478,278)
December	$ (478,278)	97,575	(380,703)	(429,490)	3.25%	(1,163)	(381,866)
January 2014	$ (381,866)	138,086	(243,780)	(312,823)	3.25%	(847)	(244,627)
February	$ (244,627)	135,566	(109,062)	(176,845)	3.25%	(479)	(109,541)
March	$ (109,541)	126,719	17,178	(46,181)	3.25%	(125)	17,053
April	$ 17,053	85,791	102,844	59,949	3.25%	162	103,007
May	$ 103,007	41,893	144,899	123,953	3.25%	336	145,235
June	$ 145,235	19,393	164,628	154,932	3.25%	420	165,048
July	$ 165,048	13,965	179,013	172,030	3.25%	466	179,479
August	$ 179,479	12,612	192,091	185,785	3.25%	503	192,594
September	$ 192,594	13,973	206,567	199,580	3.25%	541	207,107
October	$ 207,107	21,252	228,359	217,733	3.25%	590	228,949
Totals		730,886				(922)	

Balance Transferred ToWinter Period Direct Costs	(103,007)
Balance Transferred To Summer Period Direct Costs	(125,942)
Remaining October Balance	0

***NOTE**: In DG 13-257, the Company incorrectly calculated the expected share of PNGTS capacity to be assigned to marketers. Thus, the Company's proposed assignment of the expected PNGTS refund to marketers was inaccurate and low. This reconciliation balance corrects for the errors and reflects the actual refund to marketers.

ANNUAL COMMODITY - Acct 242.90.01

	BEGINNING BALANCE	REFUND COLLECTIONS	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C = A + B	D = (A + C) / 2	E	F = D * (E / 12)	G = C + F
November 2013	$ -	-	0	0	3.25%	0	0
December	$ -	0	0	0	3.25%	0	0
January 2014	$ -	0	0	0	3.25%	0	0
February	$ -	0	0	0	3.25%	0	0
March	$ -	0	0	0	3.25%	0	0
April	$ -	0	0	0	3.25%	0	0
May	$ -	0	0	0	3.25%	0	0
June	$ -	0	0	0	3.25%	0	0
July	$ -	0	0	0	3.25%	0	0
August	$ -	0	0	0	3.25%	0	0
September	$ -	0	0	0	3.25%	0	0
October	$ -	0	0	0	3.25%	0	0
Totals		0				0	

Schedule 16

Provided in the Winter 2014-15 Cost-of-Gas Filing

Schedule 17

Provided in the Winter 2014-15 Cost-of-Gas Filing

Schedule 18

Provided in Winter 2014-15 Cost-of-Gas Filing

Schedule 19

Provided in Winter 2014-15 Cost-of-Gas Filing

Schedule 20

Northern Utilities, Inc.
New Hampshire Division
Schedule 20
Page 1 of 2

Hedging Plan for 2016-17
Total Company

		Peak Season					
		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Total Contracts
	Strike Prices*	$5.050	$5.000	$4.925	$4.925	$4.950	
Scheduled Option Purchases	04/28/15	18					18
	05/28/15		31				31
	06/26/15			45			45
	07/29/15				46		46
	08/27/15					37	37
	09/28/15						0
	10/29/15						0
	11/26/15						0
	12/29/15						0
	01/28/16						0
	02/25/16						0
	03/29/16						0
Expiration Schedule	04/28/16						0
	05/27/16						0
	06/28/16						0
	07/28/16						0
	08/29/16						0
	09/28/16						0
	10/27/16	-18					-18
	11/28/16		-31				-31
	12/29/16			-45			-45
	01/27/17				-46		-46
	02/24/17					-37	-37
	03/29/17						0
	Scheduled	18	31	45	46	37	177

Futures Price*	$3.323	$3.513	$3.671	$3.667	$3.619	
2.50%	$0.0831	$0.0878	$0.0918	$0.0917	$0.0905	
Option Budget	$14,958	$27,218	$41,310	$42,182	$33,485	$159,153

* Futures and strike prices shown reflect market prices on January 30, 2015. Actual strike prices will reflect transactions made.

Northern proposes an option budget equal to 2.5 percent of the value of the futures contracts at the time the options are purchased. The calculation above shows the expected dollar budget using recent market data. Actual program expenditures will be the result of applying the budget percentage to futures contract value at the time of purchase.

3-Year Outlook for Annual Hedging Plans
Total Company

Line	Description	City-Gate Volumes	Percent of Sendout	Financial Contracts	City-Gate Volumes	Percent of Sendout	Financial Contracts	City-Gate Volumes	Percent of Sendout	Financial Contracts
	WINTER PERIOD	WINTER 2016-17			WINTER 2017-18			WINTER 2018-19		
1	Sendout Requirement (Nov-Mar)	5,775,988			5,996,775			6,204,233		
2	Target Hedged Volume (70%)	4,043,191	70%		4,197,742	70%		4,342,963	70%	
3	Washington 10 Storage	2,036,329	35%		2,036,329	34%		2,036,329	33%	
4	Tennessee Storage	232,403	4%		232,403	4%		232,403	4%	
5	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
6	Physically Hedged Volume (=3+4+5)	2,268,733	39%		2,268,733	38%		2,268,733	37%	
7	Financial Hedge Volume (=2-6)	1,770,000	31%	177	1,930,000	32%	193	2,070,000	33%	207
8	Total Hedged Volume (=6+7)	4,038,733	70%		4,198,733	70%		4,338,733	70%	

Schedule 21

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 8,898,754
Storage Demand	$ 28,915,939
Peaking Demand	$ 4,762,011
Subtotal Demand	$ 42,576,704
Capacity Release (Credit)	$ (147,616)
Asset Management (Credit)	$ (11,198,056)
Total Net Demand Costs	$ 31,231,031

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	1,008,009	1,042,708	992,395	867,776	982,738	784,754	602,881	430,805	387,566	393,070	470,187	697,279	8,660,168
Rank	2	1	3	5	4	6	8	10	12	11	9	7	
% Max Month	96.67%	100.00%	95.17%	83.22%	94.25%	75.26%	57.82%	41.32%	37.17%	37.70%	45.09%	66.87%	
PR	0.75%	3.33%	0.31%	1.59%	2.76%	1.40%	1.59%	0.36%	3.10%	0.05%	0.42%	1.29%	16.94%
CumPR	13.62%	16.94%	12.87%	9.80%	12.56%	8.21%	5.52%	3.51%	3.10%	3.15%	3.93%	6.81%	100.00%
Product and Pipeline Demand Costs	$ 1,211,604	$ 1,507,729	$ 1,144,977	$ 872,225	$ 1,117,503	$ 730,518	$ 491,007	$ 312,107	$ 275,633	$ 279,903	$ 349,451	$ 606,096	$ 8,898,754

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Storage Injection Volume	-	-	-	-	-	29,679	30,668	29,679	30,668	30,668	29,679	30,668	211,710
Design Year Pipeline Sendout	1,008,009	1,042,708	992,395	867,776	982,738	784,754	602,881	430,805	387,566	393,070	470,187	697,279	8,660,168
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	4.8%	6.4%	7.3%	7.2%	5.9%	4.2%	2.4%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 26,621	$ 23,768	$ 20,116	$ 20,212	$ 20,258	$ 20,748	$ 25,535	$ 157,258

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Storage	235,853	766,685	934,239	814,550	512,843	-	-	-	-	-	-	-	3,264,169
Rank	5	3	1	2	4	6	6	6	6	6	6	6	
% Max Month	25.25%	82.07%	100.00%	87.19%	54.89%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	5.05%	9.06%	12.81%	2.56%	7.41%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.89%
CumPR	5.05%	21.52%	36.89%	24.08%	12.46%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ 1,459,991	$ 6,222,211	$ 10,667,494	$ 6,962,949	$ 3,603,294	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,915,939
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 26,621	$ 23,768	$ 20,116	$ 20,212	$ 20,258	$ 20,748	$ 25,535	$ 157,258
TOTAL	$ 1,459,991	$ 6,222,211	$ 10,667,494	$ 6,962,949	$ 3,603,294	$ 26,621	$ 23,768	$ 20,116	$ 20,212	$ 20,258	$ 20,748	$ 25,535	$ 29,073,197

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	2,100	24,211	181,784	139,277	12,222	2,100	2,170	2,100	2,170	2,170	2,100	2,170	374,575
Rank	12	3	1	2	4	11	8	10	7	6	9	5	
% Max Month	1.16%	13.32%	100.00%	76.62%	6.72%	1.16%	1.19%	1.16%	1.19%	1.19%	1.16%	1.19%	
PR	0.10%	2.20%	23.38%	31.65%	1.38%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	58.71%
CumPR	0.10%	3.68%	58.71%	35.33%	1.48%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	100.00%
Peaking Demand Costs	$ 4,584	$ 175,333	$ 2,795,984	$ 1,682,456	$ 70,647	$ 4,584	$ 4,814	$ 4,584	$ 4,814	$ 4,814	$ 4,584	$ 4,814	$ 4,762,011

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

1		
2		`
3	Pipeline Demand	Schedule 5A, PG 1, LN 1
4	Storage Demand	Schedule 5A, PG 1, LN 2 & 3
5	Peaking Demand	Schedule 5A, PG 1, LN 4 & 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	Schedule 5A, PG 6
9	Asset Management (Credit)	Schedule 5A, PG 6
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 BETWEEN ME & NH DIVISIONS

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual
50	Pipeline & Product Demand	$ 1,211,604	$ 1,507,729	$ 1,144,977	$ 872,225	$ 1,117,503	$ 730,518	$ 491,007	$ 312,107	$ 275,633	$ 279,903	$ 349,451	$ 606,096	$ 8,898,754
51	Storage Incld Inj Fees	$ 1,459,991	$ 6,222,211	$ 10,667,494	$ 6,962,949	$ 3,603,294	$ 26,621	$ 23,768	$ 20,116	$ 20,212	$ 20,258	$ 20,748	$ 25,535	$ 29,073,197
52	Peaking	$ 4,584	$ 175,333	$ 2,795,984	$ 1,682,456	$ 70,647	$ 4,584	$ 4,814	$ 4,584	$ 4,814	$ 4,814	$ 4,584	$ 4,814	$ 4,762,011
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (26,621)	$ (23,768)	$ (20,116)	$ (20,212)	$ (20,258)	$ (20,748)	$ (25,535)	$ (157,258)
54	Less: Capacity Release	$ (29,523)	$ (29,523)	$ (29,523)	$ (29,523)	$ (29,523)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (147,616)
55	Less: Asset Mgmt	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$(1,866,343)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,198,056)
56	Total Demand	$ 780,313	$ 6,009,407	$ 12,712,589	$ 7,621,765	$ 2,895,578	$(1,131,240)	$ 495,821	$ 316,691	$ 280,446	$ 284,717	$ 354,036	$ 610,909	$ 31,231,031

57

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

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual
60	**Therms**													
61	Maine	667,393	960,802	1,093,905	948,177	788,725	410,547	328,696	243,924	222,698	225,304	262,650	370,667	6,523,488
62	New Hampshire	578,569	872,802	1,014,514	873,426	719,078	376,307	276,355	188,981	167,038	169,936	209,637	328,782	5,775,425
63	Total	1,245,962	1,833,604	2,108,419	1,821,603	1,507,803	786,854	605,051	432,905	389,736	395,240	472,287	699,449	12,298,913

64	**Percentage of Total**	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual
65	Maine	53.56%	52.40%	51.88%	52.05%	52.31%	52.18%	54.33%	56.35%	57.14%	57.00%	55.61%	52.99%	52.34%
66	New Hampshire	46.44%	47.60%	48.12%	47.95%	47.69%	47.82%	45.67%	43.65%	42.86%	43.00%	44.39%	47.01%	47.66%
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	$417,970	$3,148,908	$6,595,636	$3,967,265	$1,514,664	($590,233)	$269,356	$178,443	$160,249	$162,301	$196,888	$323,746	$16,345,193
71	New Hampshire	$362,342	$2,860,499	$6,116,953	$3,654,500	$1,380,914	($541,007)	$226,464	$138,249	$120,197	$122,416	$157,148	$287,163	$14,885,838
72	Total	$ 780,313	$ 6,009,407	$ 12,712,589	$ 7,621,765	$ 2,895,578	$ (1,131,240)	$ 495,821	$ 316,691	$ 280,446	$ 284,717	$ 354,036	$ 610,909	$ 31,231,031

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

74	**Maine**	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	
75	Pipeline & Product Demand	$ 648,989	$ 790,045	$ 594,045	$ 454,009	$ 584,561	$ 381,153	$ 266,741	$ 175,859	$ 157,499	$ 159,557	$ 194,338	$ 321,195	$ 4,727,992	53.13%
76	Storage Incld Injection Fees	$ 782,036	$ 3,260,417	$ 5,534,585	$ 3,624,340	$ 1,884,867	$ 13,890	$ 12,912	$ 11,334	$ 11,549	$ 11,548	$ 11,539	$ 13,532	$ 15,172,549	52.19%
77	Peaking	$ 2,456	$ 91,874	$ 1,450,632	$ 875,749	$ 36,955	$ 2,392	$ 2,615	$ 2,583	$ 2,750	$ 2,744	$ 2,549	$ 2,551	$ 2,475,850	51.99%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (13,890)	$ (12,912)	$ (11,334)	$ (11,549)	$ (11,548)	$ (11,539)	$ (13,532)	$ (86,304)	54.88%
79	Capacity Release (Credit)	$ (15,814)	$ (15,470)	$ (15,317)	$ (15,367)	$ (15,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (77,412)	52.44%
80	Asset Management (Credit)	$ (999,697)	$ (977,957)	$ (968,309)	$ (971,465)	$ (976,275)	$ (973,778)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,867,481)	52.40%
81	**Total Allocated Demand**	$ 417,970	$ 3,148,908	$ 6,595,636	$ 3,967,265	$ 1,514,664	$ (590,233)	$ 269,356	$ 178,443	$ 160,249	$ 162,301	$ 196,888	$ 323,746	$ 16,345,193	52.34%

82

83	**New Hampshire**	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	
84	Pipeline & Product Demand	$ 562,614	$ 717,684	$ 550,932	$ 418,216	$ 532,942	$ 349,365	$ 224,266	$ 136,248	$ 118,134	$ 120,346	$ 155,113	$ 284,900	$ 4,170,762	46.87%
85	Storage Incld Injection Fees	$ 677,954	$ 2,961,795	$ 5,132,908	$ 3,338,609	$ 1,718,427	$ 12,731	$ 10,856	$ 8,781	$ 8,663	$ 8,710	$ 9,210	$ 12,003	$ 13,900,648	47.81%
86	Peaking	$ 2,129	$ 83,459	$ 1,345,352	$ 806,708	$ 33,692	$ 2,192	$ 2,199	$ 2,001	$ 2,063	$ 2,070	$ 2,035	$ 2,263	$ 2,286,161	48.01%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (12,731)	$ (10,856)	$ (8,781)	$ (8,663)	$ (8,710)	$ (9,210)	$ (12,003)	$ (70,954)	
88	Capacity Release	$ (13,709)	$ (14,053)	$ (14,206)	$ (14,156)	$ (14,080)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (70,204)	47.56%
89	Asset Management	$ (866,646)	$ (888,386)	$ (898,033)	$ (894,878)	$ (890,067)	$ (892,564)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,330,574)	47.60%
90	**Total Allocated Demand**	$ 362,342	$ 2,860,499	$ 6,116,953	$ 3,654,500	$ 1,380,914	$ (541,007)	$ 226,464	$ 138,249	$ 120,197	$ 122,416	$ 157,148	$ 287,163	$ 14,885,838	47.66%

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ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

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

		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	320,053	204,212	184,685	187,064	213,838	413,014	6,741,888	1,522,866
3	Total Storage	0	0	0	0	0	0	1,456,132	0
4	Total Peaking	2,170	2,100	2,170	2,170	2,100	2,170	208,643	12,880
5	Total Off-system Sales							(105,967)	
6	Subtotal	322,223	206,312	186,855	189,234	215,938	415,184	8,300,696	1,535,746
7	Less Interruptible - Maine	0	0	0	0	0	0	0	0
8	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
9	Total Firm Supply	322,223	206,312	186,855	189,234	215,938	415,184	8,300,696	1,535,746
10	Total Firm Pipeline Sendout	320,053	204,212	184,685	187,064	213,838	413,014	6,741,888	1,522,866
11	**Variable Costs**								
12	Pipeline Costs Modeled in Sendout™	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 47,841,876	$ 3,790,308
13	NYMEX Price Used for Forecast	$2.916	$2.951	$3.001	$3.009	$2.996	$3.020		
14	NYMEX Price Used for Update	$2.916	$2.951	$3.001	$3.009	$2.996	$3.020		
15	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
16	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		
17	Total Updated Pipeline Costs	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 46,729,380	$ 3,790,308
18									
19	Total Pipeline	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 46,729,380	$ 3,790,308
20	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,439,906	$ -
21	Total Peaking	$ 29,595	$ 28,095	$ 28,331	$ 27,638	$ 26,073	$ 26,454	$ 4,111,318	$ 166,186
22	Total Off-sytem Sales							$ (871,801)	
23									
24	Subtotal	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 56,408,804	$ 3,956,495
25									
26	Hedging Expense & (Gain)/Loss Estimate								
27	NYMEX Options Contracts								
28	Number of contracts	-	-	-	-	-	-	54	-
29	Option Contract Price								
30	Hedging Expense							$ 58,460	
31	NYMEX Option Strike Price	$ -	$ -	$ -	$ -	$ -	$ -		
32	NYMEX Price Used for Forecast	$ 2.916	$ 4.579	$ 4.579	$ 4.579	$ 4.579	$ 4.579		
33	Strike Price Hit	$ -							
34	Option Hedging Gain (Credit)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Option Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 58,460	$ -
36									
37	Interruptible Cost Estimate								
38	Variable Pipeline Costs Excld Hedges	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 46,729,380	$ 3,790,308
39	Average Supply Cost ($/MMBtu)	$ 2.516	$ 2.344	$ 2.373	$ 2.313	$ 2.314	$ 2.761		
40	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42									
43	Firm Sales Pipeline Commodity Excld Hedge	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 46,729,380	$ 3,790,308
44	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,439,906	$ -
45	Total Peaking	$ 29,595	$ 28,095	$ 28,331	$ 27,638	$ 26,073	$ 26,454	$ 4,111,318	$ 166,186
46	Off-system Sales							$ (871,801)	
47	Firm Sales Variable Costs Excld Hedge	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 56,408,804	$ 3,956,495
48	Plus Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	$ 58,460	$ -
49	Total Firm Sales Variable Costs	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 56,467,264	$ 3,956,495

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 6A, page 2
3	Total Storage	Schedule 6A, page 2
4	Total Peaking	Schedule 6A, page 2
5	Total Off-system Sales	Schedule 6A, page 2
6	Subtotal	SUM LN 2: LN 4
7	Less Interruptible - Maine	Company Analysis
8	Less Interruptible - New Hampshire	Company Analysis
9	Total Firm Supply	LN 6 - LN 7 - LN 8
10	Total Firm Pipeline Sendout	LN 2 - LN 7 - LN 8
11	Variable Costs	
12	Pipeline Costs Modeled in Sendout™	0
13	NYMEX Price Used for Forecast	Attachment to Schedule 5A, PG 1, LN 22
14	NYMEX Price Used for Update	Attachment to Schedule 5A, PG 1, LN 22
15	Increase/(Decrease) NYMEX Price	LN 14 - LN 13
16	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 15
17	Total Updated Pipeline Costs	LN 16 + LN 12
18		
19	Total Pipeline	LN 17
20	Total Storage	LN 3
21	Total Peaking	LN 4
22	Total Off-sytem Sales	LN 5
23		
24	Subtotal	Sum LN 18 : LN 20
25		
26	Hedging Expense & (Gain)/Loss Estimate	
27	NYMEX Options Contracts	
28	Number of contracts	Schedule 7
29	Option Contract Price	Schedule 7
30	Hedging Expense	LN 28 * LN 29
31	NYMEX Option Strike Price	Schedule 7
32	NYMEX Price Used for Forecast	Line 13
33	Strike Price Hit	IF LN 31 < LN 32, Yes ELSE No
34	Option Hedging Gain (Credit)	(LN 32 - LN 31)* LN 28 * 10,000
35	Total Option Cost	LN 30 + LN 34
36		
37	Interruptible Cost Estimate	
38	Variable Pipeline Costs Excld Hedges	LN 17
39	Average Supply Cost ($/MMBtu)	LN 38 / LN 2
40	Interruptible Cost - Maine	LN 39 * LN 7
41	Interruptible Cost - New Hampshire	LN 39 * LN 8
42		
43	Firm Sales Pipeline Commodity Excld Hedge	LN 38 - LN 40 - LN 41
44	Total Storage	LN 20
45	Total Peaking	LN 21
46	Off-system Sales	LN 22
47	Firm Sales Variable Costs Excld Hedge	Sum LN 43 : LN 46
48	Plus Net Hedging Expense / (Gain)	LN 35
49	Total Firm Sales Variable Costs	LN 47 + LN 48

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

50 **Commodity Allocation Factors**

51 Firm Sales Sendout for Normal Winter, MMBtu

52		May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Summer
53	Maine	170,035	104,933	94,775	93,514	111,151	219,027	4,337,727	793,435
54	New Hampshire	152,143	101,346	92,052	95,690	104,754	196,099	3,967,362	742,083
55	Total	322,178	206,279	186,827	189,204	215,905	415,126	8,305,089	1,535,518
56									
57	**Percentage of Total**								
58	Maine	52.78%	50.87%	50.73%	49.42%	51.48%	52.76%	52.23%	51.67%
59	New Hampshire	47.22%	49.13%	49.27%	50.58%	48.52%	47.24%	47.77%	48.33%
60	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
61									
62	**Commodity Allocation by Jurisdiction**								
63	**Maine**								
64	Firm Sales Pipeline Commodity Excld Hedge	$ 425,043	$ 243,470	$ 222,350	$ 213,892	$ 254,796	$ 601,656	$ 24,419,390	$ 1,961,208
65	Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,525	$ -
66	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,364,445	$ -
67	Peaking	$ 15,619	$ 14,292	$ 14,372	$ 13,660	$ 13,423	$ 13,957	$ 2,150,923	$ 85,324
68	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (456,126)	$ -
69	Total Maine Commodity Costs	$ 440,662	$ 257,762	$ 236,722	$ 227,552	$ 268,219	$ 615,614	$ 29,509,157	$ 2,046,532
70	Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,975	$ -
71	Total Maine Variable Costs	$ 440,662	$ 257,762	$ 236,722	$ 227,552	$ 268,219	$ 615,614	$ 29,516,132	$ 2,046,532
72	**New Hampshire**								
73	Firm Sales Pipeline Commodity Excld Hedge	$ 380,316	$ 235,148	$ 215,961	$ 218,870	$ 240,132	$ 538,673	$ 22,309,990	$ 1,829,100
74	Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	`	$ -
75	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,075,461	$ -
76	Peaking	$ 13,975	$ 13,803	$ 13,959	$ 13,978	$ 12,650	$ 12,496	$ 1,960,396	$ 80,863
77	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (415,675)	$ -
78	Total New Hampshire Commodity Costs	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 26,958,107	$ 1,909,963
79	New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,483	$ -
80	Total New Hampshire Variable Costs	$ 394,292	$ 248,951	$ 229,920	$ 232,848	$ 252,782	$ 551,170	$ 26,964,590	$ 1,909,963
81	**Northern Utilities**								
82	Firm Sales Pipeline Commodity Excld Hedge	$ 805,359	$ 478,618	$ 438,311	$ 432,762	$ 494,928	$ 1,140,330	$ 46,729,380	$ 3,790,308
83	Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	$ 58,460	$ -
84	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,439,906	$ -
85	Peaking	$ 29,595	$ 28,095	$ 28,331	$ 27,638	$ 26,073	$ 26,454	$ 4,111,318	$ 166,186
86	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (871,801)	$ -
87	Total Northern Commodity Costs	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 56,467,264	$ 3,956,495
88	Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,458	$ -
89	Total Northern Variable Costs	$ 834,954	$ 506,713	$ 466,643	$ 460,400	$ 521,001	$ 1,166,784	$ 56,480,722	$ 3,956,495
90									

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

50	**Commodity Allocation Factors**	
51	Firm Sales Sendout for Normal Winter, MMBtu	
52		
53	Maine	Company Analysis
54	New Hampshire	Schedule 10B, LN 33 / 10
55	Total	LN 53 + LN 54
56		
57	**Percentage of Total**	
58	Maine	LN 53 / LN 55
59	New Hampshire	LN 54 / LN 55
60	Total	LN 58 + LN 59
61		
62	**Commodity Allocation by Jurisdiction**	
63	**Maine**	
64	Firm Sales Pipeline Commodity Excld Hedge	LN 43 * LN 58
65	Net Hedging Expense / (Gain)	LN 35 * LN 58
66	Storage	LN 44 * LN 58
67	Peaking	LN 45 * LN 58
68	Off-system Sales	LN 46 * LN 58
69	Total Maine Commodity Costs	Sum LN 64 : LN 68
70	Maine Inventory Finance Costs	LN 111
71	Total Maine Variable Costs	LN 69 + LN 70
72	**New Hampshire**	
73	Firm Sales Pipeline Commodity Excld Hedge	LN 43 * LN 59
74	Net Hedging Expense / (Gain)	LN 35 * LN 59
75	Storage	LN 44 * LN 59
76	Peaking	LN 45 * LN 59
77	Off-system Sales	LN 46 * LN 59
78	Total New Hampshire Commodity Costs	Sum LN 73 : LN 77
79	New Hampshire Inventory Finance Costs	LN 116
80	Total New Hampshire Variable Costs	LN 78 + LN 79
81	**Northern Utilities**	
82	Firm Sales Pipeline Commodity Excld Hedge	LN 64 + LN 73
83	Net Hedging Expense / (Gain)	LN 65 + LN 74
84	Storage	LN 66 + LN 75
85	Peaking	LN 67 + LN 76
86	Off-system Sales	LN 68 + LN 77
87	Total Northern Commodity Costs	LN 69 + LN 78
88	Northern Inventory Finance Costs	LN 70 + LN 79
89	Total Northern Variable Costs	LN 87 + LN 88
90		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

94

95	Col A	Col H	Col I	Col J	Col K	Col L	Col M	Col N	Col P
96									
97	**Inventory Finance Charge**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Summer**
98	Storage	$ 359	$ 533	$ 709	$ 889	$ 1,065	$ 1,242	$ 10,120	$ 4,796
99	Peaking	$ 290	$ 282	$ 275	$ 269	$ 262	$ 256	$ 3,338	$ 1,634
100	Total	$ 649	$ 815	$ 984	$ 1,157	$ 1,327	$ 1,498	$ 13,458	$ 6,431
101									
102	**Inventory Finance Charge Allocation by Jurisdiction**								
103	Maine	$ 343	$ 414	$ 499	$ 572	$ 683	$ 790	$ 6,975	$ 3,302
104	New Hampshire	$ 307	$ 400	$ 485	$ 585	$ 644	$ 708	$ 6,483	$ 3,129
105	Total	$ 649	$ 815	$ 984	$ 1,157	$ 1,327	$ 1,498	$ 13,458	$ 6,431
106									
107	**Inventory Finance Charge Allocation by Month**								
108	**Maine**								
109	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,994,610	0
110	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
111	ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,975	$ -
112									
113	**New Hampshire**								
114	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,677,194	0
115	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
116	NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,483	$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

91 **Northern Utilities**
92 **Simplified Market Based Allocator (MBA) Calculations**
93 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**
94
95
96

97	**Inventory Finance Charge**	
98	Storage	"Schedule 14 - Carrying Costs"
99	Peaking	"Schedule 14 - Carrying Costs"
100	Total	Sum LN 98 : LN 199
101		
102	**Inventory Finance Charge Allocation by Jurisdiction**	
103	Maine	LN 100 * LN 58
104	New Hampshire	LN 100 * LN 59
105	Total	Sum LN 103 : LN 104
106		
107	**Inventory Finance Charge Allocation by Month**	
108	**Maine**	
109	Firm Sales Remaining Sendout	0
110	Monthly % Sendout of Total Winter	LN 109 / LN 109 Col N
111	ME Allocated Inventory Finance Charge	LN 103 Col N * LN 110
112		
113	**New Hampshire**	
114	Firm Sales Remaining Sendout	0
115	Monthly % Sendout of Total Winter	LN 114 / LN 114 Col N
116	NH Allocated Inventory Finance Charge	LN 104 Col N* LN 115

Schedule 23

Northern Utilities, Inc.
New Hampshire Division
Schedule 23
Page 1 of 1

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

		Winter	Summer	Annual	
1	Demand	$ 11,719,923	$ 901,217	$ 12,621,140	Schedule 1A, LN 80
2	Commodity	$ 25,470,302	$ 1,909,963	$ 27,380,265	Schedule 1B, LN 43
3	Total	$ 37,190,225	$ 2,811,180	$ 40,001,405	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	32,046,338	7,371,305	39,417,643	Schedule 10B, LN 11
6	Forecasted Residential Sales (Therms)	14,756,521	3,308,911	18,065,432	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Annual**	
8	Average Demand Rate	$0.3657	$0.1223		LN 1 / LN 5
9	Average Commodity Rate	$0.7948	$0.2591		LN 2 / LN 5
10	Average Rate	$1.1605	$0.3814		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Annual**	
13	Demand Costs Allocated To Residential per SMBA	$ 5,340,144	$ 408,507	$ 5,748,651	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 5,396,725	$ 404,680	$ 5,801,405	LN 8 * LN 6
15	**Demand Reallocation:**	$ (56,581)	$ 3,828	$ (52,754)	LN 13 - LN 14
16	**HLF Allocation**	$ (5,164)	$ 741	$ (4,422)	LN 15 / LN 20
17	**LLF Allocation**	$ (51,418)	$ 3,087	$ (48,331)	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	9.13%	19.36%		Schedule 10A, LN 173
21	LLF	90.87%	80.64%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 11,728,784	$ 857,616	$ 12,586,400	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 11,728,424	$ 857,339	$ 12,585,763	LN 9 * LN 6
25	**Commodity Reallocation:**	$ 360	$ 277	$ 637	LN 23 - LN 24
26	**HLF Allocation**	$ 47	$ 104	$ 151	LN 25 * LN 30
27	**LLF Allocation**	$ 313	$ 173	$ 486	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	13.03%	37.61%		Schedule 10C, LN 143
31	LLF	86.97%	62.39%		Schedule 10C, LN 144

Schedule 24

Provided in Winter 2014-15 Cost-of-Gas Filing