Schedules 1A and 1B

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

NH Division Total Annual Demand Cost Allocation

1	**Resource**	**Costs**
2	Pipeline & Product Demand	$ 3,656,128
3	Storage	$ 10,609,016
4	Peaking	$ 2,353,841
5	Total Gross Demand Cost	$ 16,618,986
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,597,013
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 16,618,986
9	Capacity Assignment as % of Total Gross Demand Cost	15.63%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 571,335
14	Storage	$ 1,657,848
15	Peaking	$ 367,830
16	Total Capacity Assignment Credit	$ 2,597,013
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,084,793
21	Storage	$ 8,951,168
22	Peaking	$ 1,986,012
23	Total Net Demand Cost (Less Capacity Assignment)	$ 14,021,973
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	16,170
28	Less 15.63% NH Transp. Capacity Assignment	(2,527)
29	Net Pipeline MDQ	13,643
30		
31	Net Pipeline MDQ	13,643
32	Less: Firm Sales Base Use	4,098
33	Remaining Pipeline MDQ	9,545
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$226.11
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,084,793
40	Less: Base Pipeline Use	$ 926,636
41	Remaining Pipeline Use	$ 2,158,157

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	2015-2016 Winter Period Filing, Schedule 5B, Page 1 & Company Analysis
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 15.63% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

All Months	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for All Months	3,159,455	5,104,385	6,755,855	5,521,379	3,955,826	1,955,318
Rank	5	3	1	2	4	6
% Max Month	46.77%	75.55%	100.00%	81.73%	58.55%	28.94%
PR	3.56%	5.67%	18.27%	3.09%	2.95%	1.41%
CumPR	7.63%	16.24%	37.60%	19.33%	10.57%	4.06%

Peak Months Only	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for Peak Months Only	3,159,455	5,104,385	6,755,855	5,521,379	3,955,826	1,955,318
Rank	5	3	1	2	4	6
% Max Month	46.77%	75.55%	100.00%	81.73%	58.55%	28.94%
PR	3.56%	5.67%	18.27%	3.09%	2.95%	4.82%
CumPR	8.39%	17.00%	38.36%	20.09%	11.34%	4.82%

DEMAND COST PR ALLOCATORS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
Pipeline - Remaining	7.63%	16.24%	37.60%	19.33%	10.57%	4.06%
Storage & Peaking	7.63%	16.24%	37.60%	19.33%	10.57%	4.06%
Capacity Release	8.39%	17.00%	38.36%	20.09%	11.34%	4.82%
Interr. Margins & Off Sys Sales	8.39%	17.00%	38.36%	20.09%	11.34%	4.82%

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	$ 77,220	$ 77,220	$ 77,220	$ 77,220	$ 77,220	$ 77,220
Pipeline - Remaining	$ 164,604	$ 350,506	$ 811,464	$ 417,110	$ 228,204	$ 87,671
Total Pipeline	$ 241,823	$ 427,726	$ 888,683	$ 494,330	$ 305,423	$ 164,891
Storage & Peaking	$ 834,183	$ 1,776,306	$ 4,112,362	$ 2,113,845	$ 1,156,498	$ 444,303
Less Credits to Demand Cost						
Cap Rel Margins, Asset Mgt Credit & PNGTS Refund	$ 285,353	$ 578,375	$ 1,304,943	$ 683,358	$ 385,600	$ 164,091
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
PNGTS Refund - Winter Only Contract	$ 153,853	$ 327,614	$ 758,465	$ 389,868	$ 213,299	$ 81,945
PNGTS Refund - Annual Contract	$ 6,005	$ 6,005	$ 6,005	$ 6,005	$ 6,005	$ 6,005
Total Direct Demand Costs	$ 630,796	$ 1,292,038	$ 2,931,632	$ 1,528,945	$ 857,017	$ 357,153
Indirect Demand Costs/(Credits)						
Miscellaneous Overhead						
Local Production & Storage						
Subtotal						

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

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

All Months	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
Remaining Load for All Months	788,625	142,157	0	24,625	188,287	1,383,515	28,979,426	26,452,218	2,527,209
Rank	8	10	12	11	9	7			
% Max Month	11.67%	2.10%	0.00%	0.36%	2.79%	20.48%			
PR	1.11%	0.17%	0.00%	0.03%	0.08%	1.26%	37.60%		
CumPR	1.39%	0.21%	0.00%	0.03%	0.28%	2.65%	100.00%	95.43%	4.57%

Peak Months Only	**Annual**	**Winter**	**Summer**
Remaining Load for Peak Months Only	26,452,218	26,452,218	
Rank			
% Max Month			
PR	38.36%		
CumPR	100.00%	100.00%	0.00%

DEMAND COST PR ALLOCATORS

	May	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
Pipeline - Remaining	1.39%	0.21%	0.00%	0.03%	0.28%	2.65%	100.00%	95.43%	4.57%
Storage & Peaking	1.39%	0.21%	0.00%	0.03%	0.28%	2.65%	100.00%	95.43%	4.57%
Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

DEMAND COSTS ALLOCATED TO MONTHS

	May	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**	**Winter**	**Summer**
Pipeline - Base	$ 77,220	$ 77,220	$ 77,220	$ 77,220	$ 77,220	$ 77,220	$ 926,636	$ 463,318	$ 463,318	50.00%	50.00%
Pipeline - Remaining	$ 30,079	$ 4,470	$ -	$ 715	$ 6,107	$ 57,227	$ 2,158,157	$ 2,059,558	$ 98,599	95.43%	4.57%
Total Pipeline	$ 107,299	$ 81,689	$ 77,220	$ 77,935	$ 83,327	$ 134,447	$ 3,084,793	$ 2,522,876	$ 561,917	81.78%	18.22%
Storage & Peaking	$ 152,437	$ 22,652	$ -	$ 3,624	$ 30,949	$ 290,019	$ 10,937,180	$ 10,437,499	$ 499,682	95.43%	4.57%
Less Credits to Demand Cost											
Cap Rel Margins, Asset Mgt Credit & PNGTS Refund	$ -	$ -	$ -	$ -	$ -	$ -	$3,401,720	$ 3,401,720	$ -	100.00%	0.00%
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
PNGTS Refund - Winter Only Contract	$ 28,115	$ 4,178	$ -	$ 668	$ 5,708	$ 53,490	$ 2,017,202	$ 1,925,043	$ 92,159	95.43%	4.57%
PNGTS Refund - Annual Contract	$ 6,005	$ 6,005	$ 6,005	$ 6,005	$ 6,005	$ 6,005	$ 72,063	$ 36,031	$ 36,031	50.00%	50.00%
Total Direct Demand Costs	$ 225,616	$ 94,158	$ 71,214	$ 74,885	$ 102,563	$ 364,972	$ 8,530,989	$ 7,597,581	$ 933,408	89.06%	10.94%
Indirect Demand Costs/(Credits)											
Miscellaneous Overhead							$ 512,668	$ 394,798	$ 117,870	77.01%	22.99%
Local Production & Storage							$ 420,658	$ 420,658	$ -	100.00%	0.00%
Subtotal							$ 933,326	$ 815,456	$ 117,870	87.37%	12.63%

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 & PNGTS Refund	Schedule 1A, Page 6, Line 6
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79	PNGTS Refund - Winter Only Contract	Schedule 25
80	PNGTS Refund - Annual Contract	Schedule 25
81	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 80)
82		
83	Indirect Demand Costs/(Credits)	
84	Miscellaneous Overhead	Company Analysis
85	Local Production & Storage	Company Analysis
86	Subtotal	LN 84 + LN 85

New Hampshire Asset Management and Capacity Release Revenue

		A Total	B Capacity Assigned	C Sales	D Total	E Capacity Assigned	F Sales
1	Asset Management	($3,966,157)	($591,775)	($3,374,382)	Schedule 21, Line 89	Schedule 5B, Page 5*	A - B
2	Capacity Release Revenues	($27,338)	$0	($27,338)	Schedule 21, Line 88		A - B
3	Total NH Cap Rel and Asset Management	($3,993,495)	($591,775)	($3,401,720)			Sum (LN1 + LN 2 + LN 5)

*: Provided in the 2015-2016 Winter Period Filing

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	Summer
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	2,050,412	1,362,847	1,236,724	1,285,694	1,409,103	2,645,300	35,532,345	9,990,080
2	New Hampshire Sales Storage	0	0	0	0	0	0	7,036,092	0
3	New Hampshire Sales Peaking	8,648	8,763	9,086	9,366	8,637	8,650	1,105,762	53,150
4	Total New Hampshire Firm Sales Sendout	2,059,060	1,371,610	1,245,810	1,295,060	1,417,740	2,653,950	43,674,200	10,043,230
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	2,059,060	1,371,610	1,245,810	1,295,060	1,417,740	2,653,950	43,674,200	10,043,230
9	Total Firm Sales	2,038,088	1,357,429	1,232,909	1,281,652	1,403,103	2,627,052	43,234,360	9,940,234
10	Difference (LAUF & Company Use)	20,972	14,181	12,901	13,408	14,637	26,898	439,840	102,995
11	Percent Difference	1.02%	1.03%	1.04%	1.04%	1.03%	1.01%	1.01%	1.03%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 382,903	$ 252,293	$ 234,587	$ 250,812	$ 286,762	$ 633,326	$ 16,230,697	$ 2,040,682
15	New Hampshire Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,993	$ -
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,202,214	$ -
17	New Hampshire Total Peaking	$ 8,068	$ 8,190	$ 8,519	$ 8,798	$ 8,158	$ 8,199	$ 982,350	$ 49,933
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,487	$ -
19	Total New Hampshire Sales Variable Costs	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,501,741	$ 2,090,615
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,417,748	$ 2,090,615
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,501,741	$ 2,090,615
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.1867	$ 0.1851	$ 0.1897	$ 0.1951	$ 0.2035	$ 0.2394	$ 0.4568	$ 0.2043
27	New Hampshire Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0024	$ -
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3130	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.9330	$ 0.9346	$ 0.9376	$ 0.9393	$ 0.9446	$ 0.9479	$ 0.8884	$ 0.9395
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0003	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.1899	$ 0.1899	$ 0.1951	$ 0.2005	$ 0.2080	$ 0.2417	$ 0.4465	$ 0.2082
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	1,270,435	1,229,453	1,245,810	1,270,435	1,229,453	1,270,435	14,694,774	7,516,021
37	Base Commodity Cost Excld Hedging	$ 237,246	$ 227,599	$ 236,310	$ 247,835	$ 250,202	$ 304,162	$ 5,419,817	$ 1,503,355
38	Base Hedging Commodity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,704	$ -
39	Remaining Commodity Excld Hedging	$ 153,724	$ 32,884	$ 6,796	$ 11,774	$ 44,718	$ 337,363	$ 13,997,930	$ 587,261
40	Remaining Hedging Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,289	$ -
41	Total Commodity Excld Hedging	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,417,748	$ 2,090,615
42	Total Hedging	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,993	$ -
43	Total Commodity (Incl Hedging)	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,501,741	$ 2,090,615

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 77
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 2016 through October 2016			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	[redacted]	446,312	[redacted]
Tennessee Production		1,162,363	
Niagara		56,162	
PNGTS Receipts		183,356	
PNGTS Delivered		495,061	
TGP Zone 6		70,166	
Maritimes Delivered		62,000	
LNG		13,064	
Total Delivered Commodity Cost	$5,186,841	2,488,485	$2.084

Schedule 3

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

Line	Sales Revenues	Oct-15	Winter Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Summer (Forecast) May-16	(Forecast) Jun-16	(Forecast) Jul-16	(Forecast) Aug-16	(Forecast) Sep-16	(Forecast) Oct-16	Total
1	Volumes														
2	Residential Heat & Non Heat								711,597	473,945	430,469	447,488	489,892	917,233	3,470,624
3	Sales HLF Classes								713,054	474,916	431,351	448,404	490,895	919,111	3,477,731
4	Sales LLF Classes								613,438	408,568	371,089	385,760	422,315	790,708	2,991,879
5	Total								2,038,088	1,357,429	1,232,909	1,281,652	1,403,103	2,627,052	9,940,234
6	Rates														
7	Residential Heat & Non Heat CGA								$0.3196	$0.3196	$0.3196	$0.3196	$0.3196	$0.3196	
8	Sales HLF Classes CGA								$0.2832	$0.2832	$0.2832	$0.2832	$0.2832	$0.2832	
9	Sales LLF Classes CGA								$0.3619	$0.3619	$0.3619	$0.3619	$0.3619	$0.3619	
10	Revenues														
11	Residential Heat & Non Heat								$ (227,426)	$ (151,473)	$ (137,578)	$ (143,017)	$ (156,570)	$ (293,148)	$ (1,109,211)
12	Sales HLF Classes								$ (201,937)	$ (134,496)	$ (122,159)	$ (126,988)	$ (139,022)	$ (260,292)	$ (984,894)
13	Sales LLF Classes								$ (222,003)	$ (147,861)	$ (134,297)	$ (139,607)	$ (152,836)	$ (286,157)	$ (1,082,761)
14	Total Sales								$ (651,366)	$ (433,830)	$ (394,034)	$ (409,612)	$ (448,427)	$ (839,597)	$ (3,176,866)
15															

Line	Gas Costs and Credits	Oct-15	Winter Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Summer (Forecast) May-16	(Forecast) Jun-16	(Forecast) Jul-16	(Forecast) Aug-16	(Forecast) Sep-16	(Forecast) Oct-16	Total
16															
17															
18															
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 87,648	$ 87,648	$ 87,648	$ 87,648	$ 87,648	$ 87,648	$ 525,885
21	Storage								$ 55,694	$ 55,694	$ 55,694	$ 55,694	$ 55,694	$ 55,694	$ 334,164
22	Peaking								$ 12,226	$ 12,226	$ 12,226	$ 12,226	$ 12,226	$ 12,226	$ 73,358
24	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 155,568	$ 155,568	$ 155,568	$ 155,568	$ 155,568	$ 155,568	$ 933,408
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								521,843	331,246	299,589	302,138	347,502	673,103	2,475,421
27	Pipeline Costs Modeled in Sendout™								$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 5,064,105
28	NYMEX Price Used for Forecast								$ 1.7870	$ 1.9000	$ 1.9960	$ 2.0460	$ 2.0650	$ 2.1070	
29	NYMEX Price Used for Update								$ 1.7870	$ 1.9000	$ 1.9960	$ 2.0460	$ 2.0650	$ 2.1070	
30	Increase/(Decrease) NYMEX Price														
31	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
32	Updated Pipeline Costs								$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 1.87	$ 1.85	$ 1.90	$ 1.95	$ 2.04	$ 2.39	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	
37	New Hampshire Allocated Percentage								39.29%	41.14%	41.28%	42.55%	40.55%	39.30%	
38	NH Updated Pipeline Costs								$ 382,903	$ 252,293	$ 234,587	$ 250,812	$ 286,762	$ 633,326	$ 2,040,682
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								0	0	0	0	0	0	
42	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
43	NYMEX Price Used for Forecast								$ 1.7870	$ 1.9000	$ 1.9960	$ 2.0460	$ 2.0650	$ 2.1070	
44	NYMEX Price Used for Update								$ 1.7870	$ 1.9000	$ 1.9960	$ 2.0460	$ 2.0650	$ 2.1070	
45	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	New Hampshire Allocated Percentage								39.29%	41.14%	41.28%	42.55%	40.55%	39.30%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Price Triggered NYMEX Contracts (NH Only)														
50	NYMEX NG Futures Contracts								$ -	$ -	$ -	$ -	$ -	$ -	
51	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
52	NYMEX Price Used for Forecast								$ 1.7870	$ 1.9000	$ 1.9960	$ 2.0460	$ 2.0650	$ 2.1070	
53	NYMEX Price Used for Update								$ 1.7870	$ 1.9000	$ 1.9960	$ 2.0460	$ 2.0650	$ 2.1070	
54	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
55	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	New Hampshire Allocated Percentage								100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
57	NH Futures Hedging (Gain)/Loss, Price Triggered								$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	NH Commodity Costs														
59	Pipeline Excl Hedging								$ 382,903	$ 252,293	$ 234,587	$ 250,812	$ 286,762	$ 633,326	$ 2,040,682
60	Hedging (Gain)/Loss Estimate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Peaking								$ 8,068	$ 8,190	$ 8,519	$ 8,798	$ 8,158	$ 8,199	$ 49,933
63	Total Commodity Costs								$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 2,090,615

Northern Utilities

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

64	Inventory Finance Charge													$ -
65	Asset Management and Capacity Release													
66	NUI AMA Revenue													$ -
67	PNGTS Litigation Cost													$ -
68	NUI Capacity Release													$ -
69	NUI AMA Rev & Cap. Release Subtotal													$ -
70	NH AMA Revenue													$ -
71	NH Capacity Release													$ -
72	NH Total Asset Management and Capacity Release		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73														
74	**Total Anticipated Direct Cost of Gas**		$ -	$ -	$ -	$ -	$ -	$ -	$ 546,539	$ 416,051	$ 398,674	$ 415,177	$ 450,488	$ 797,093	$ 3,024,024
75			Winter						Summer						
76									(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 546,539	$ 416,051	$ 398,674	$ 415,177	$ 450,488	$ 797,093	$ 3,024,024
80	Working Capital Percentage		0.0887%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	
81	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -	$ -	$ 485	$ 369	$ 354	$ 368	$ 400	$ 707	$ 2,682
82	Beginning Period Working Capital Balance		$ (431)	$ (432)	$ (434)	$ (435)	$ (436)	$ (437)	$ (439)	$ 46	$ 415	$ 771	$ 1,142	$ 1,545	
83	End of Period Working Capital Allowance		$ (431)	$ (432)	$ (434)	$ (435)	$ (436)	$ (437)	$ 46	$ 415	$ 769	$ 1,139	$ 1,541	$ 2,252	
84	Interest		$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ 1	$ 2	$ 3	$ 4	$ 6	$ 6
85	End of period with Interest	$ (431)	$ (432)	$ (434)	$ (435)	$ (436)	$ (437)	$ (439)	$ 46	$ 415	$ 771	$ 1,142	$ 1,545	$ 2,258	
86	Bad Debt														
92	Projected Bad Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,815	$ 3,815	$ 3,815	$ 3,815	$ 3,815	$ 3,815	$ 22,890
93	Beginning Period Bad Debt Balance		$ (12,773)	$ (12,810)	$ (12,848)	$ (12,885)	$ (12,923)	$ (12,960)	$ (12,998)	$ (9,215)	$ (5,422)	$ (1,617)	$ 2,199	$ 6,026	
94	End of Period Bad Debt Balance		*$ (12,773)*	*$ (12,810)*	*$ (12,848)*	*$ (12,885)*	*$ (12,923)*	*$ (12,960)*	*$ (9,183)*	*$ (5,400)*	*$ (1,607)*	*$ 2,198*	*$ 6,014*	*$ 9,841*	
95	Interest		$ (37)	$ (37)	$ (37)	$ (38)	$ (38)	$ (38)	$ (32)	$ (21)	$ (10)	$ 1	$ 12	$ 23	$ (253)
96	End of Period Bad Debt Balance with Interest	$ (12,773)	$ (12,810)	$ (12,848)	$ (12,885)	$ (12,923)	$ (12,960)	$ (12,998)	$ (9,215)	$ (5,422)	$ (1,617)	$ 2,199	$ 6,026	$ 9,864	
97	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
98			$ -	$ -	$ -										$ -
99	Miscellaneous Overhead								$ 19,645	$ 19,645	$ 19,645	$ 19,645	$ 19,645	$ 19,645	$ 117,870
100															
101	Supplier Refund		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
101	Beginning Balance Over/Under Collection		$ 23,260	$ 22,142	$ 21,548	$ 21,644	$ 21,707	$ 21,771	$ 21,834	$ (63,409)	$ (61,725)	$ (37,584)	$ (12,446)	$ 9,256	$ (12,002)
102	Net Costs - Revenues		$ (1,184)	$ (658)	$ 33	$ -	$ -	$ -	$ (85,182)	$ 1,867	$ 24,285	$ 25,211	$ 21,706	$ (22,859)	$ (36,781)
103	Ending Balance before Interest		$ 22,076	$ 21,484	$ 21,581	$ 21,644	$ 21,707	$ 21,771	$ (63,348)	$ (61,542)	$ (37,439)	$ (12,373)	$ 9,260	$ (13,603)	$ (48,783)
104	Average Balance		$ 22,668	$ 21,813	$ 21,565	$ 21,644	$ 21,707	$ 21,771	$ (20,757)	$ (62,476)	$ (49,582)	$ (24,979)	$ (1,593)	$ (2,174)	$ (30,392)
105	Interest Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
106	Interest Expense		$ 66	$ 64	$ 63	$ 63	$ 63	$ 63	$ (61)	$ (182)	$ (145)	$ (73)	$ (5)	$ (6)	$ (89)
108	Ending Balance Incl Interest Expense	$ 23,260	$ 22,142	$ 21,548	$ 21,644	$ 21,707	$ 21,771	$ 21,834	$ (63,409)	$ (61,725)	$ (37,584)	$ (12,446)	$ 9,256	$ (13,609)	
109	**Total Over/Under Collection Ending Balance**	$ 10,056	$ 8,899	$ 8,267	$ 8,324	$ 8,349	$ 8,373	$ 8,397	$ (72,579)	$ (66,731)	$ (38,430)	$ (9,106)	$ 16,827	$ (1,488)	
110															
111	**Total Indirect Cost of Gas**	$ 10,056	$ 28	$ 25	$ 24	$ 24	$ 24	$ 24	$ 23,851	$ 23,626	$ 23,661	$ 23,759	$ 23,871	$ 24,189	$ 153,163
112															
113	**Total Cost of Gas**	$ 10,056	$ 28	$ 25	$ 24	$ 24	$ 24	$ 24	$ 570,390	$ 439,678	$ 422,335	$ 438,936	$ 474,359	$ 821,283	$ 3,177,187
114															
115	**Total Interest**	$ -	$ 28	$ 25	$ 24	$ 24	$ 24	$ 24	$ (93)	$ (203)	$ (153)	$ (69)	$ 11	$ 22	$ (335)

Schedule 4

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2015**			
2				
3	Total	$	360,081	Company Analysis
4	Distribution	$	154,072	Company Analysis
5	Distribution (%)		42.79%	
6	Non-Distribution	$	206,009	Company Analysis
7	Non-Distribution(%)		57.21%	LN 6 / LN 3
8				
9	Non-Distribution	$	206,009	LN 6
10	Peak Period	$	189,524	Company Analysis
11	Peak Period (%)		92.00%	LN 10/ LN 9
12	Off-Peak Period	$	16,485	LN 9 - LN 10
13	Off-Peak Period (%)		8.00%	LN 12 / LN 9
14				
15	**Forecast Bad Debt Expense 12 Months Ended April 30, 2016**			
16				
17	Annual Total	$	500,000	Company Forecast
18	Annual Non-Distribution	$	286,059	LN 17* LN 7
19	Winter Non-Distribution	**$**	**263,169**	LN 18* LN 11
20	Summer Non-Distribution	$	22,890	LN 18* LN 13

Schedule 5A & Attachment

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2015 through October 31, 2016				
Reference	Reference		Estimate	Reference
1.	Pipeline Demand Costs	$	8,968,294	Att NUI-CAK-14, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$	21,913,000	Att NUI-CAK-14, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$	3,029,855	Att NUI-CAK-14, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$	1,252,642	Att NUI-CAK-14, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$	4,223,000	Att NUI-CAK-14, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$	(9,629,987)	Att NUI-CAK-14, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$	29,756,804	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2015 through October 31, 2016

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ (Dth)	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)**	Months Per Year	Monthly Demand	Annual Demand
AFT-1 (AFT-2)	93002F	AFT-1 (AFT-2)	No	4,211	Mendon, MA	Brockton, MA	$ 6.1138	12	$ 25,745	$ 308,943
Algonquin	93201A1C	AFT-1 (F-2/F-3)	No	1,251	Centerville, NJ	Taunton, MA	$ 6.5734	12	$ 8,223	$ 98,680
Granite	16-100-FT-NN	FT-NN	No	115,000	NA	NA	$ 4.1069	6	$ 472,294	$ 2,833,761
Granite	16-100-FT-NN	FT-NN	No	85,000	NA	NA	$ 4.1069	3	$ 349,087	$ 1,047,260
Granite	16-100-FT-NN	FT-NN	No	85,000	NA	NA	$ 4.2845	3	$ 364,183	$ 1,092,548
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 25.9843	12	$ 28,583	$ 342,993
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 49.3701	5	$ 1,629,213	$ 8,146,067
Tennessee	5083	FT-A	No	4,605	Zone 0	Zone 6	$ 23.2362	12	$ 107,003	$ 1,284,032
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 20.6281	12	$ 176,370	$ 2,116,443
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 8.1668	12	$ 21,667	$ 259,998
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.1756	12	$ 10,089	$ 121,067
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.1756	12	$ 15,973	$ 191,675
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.1756	12	$ 6,666	$ 79,994
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.1756	12	$ 30,618	$ 367,419
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.6120	12	$ 5,416	$ 64,987
TransCanada*	33322	FT	No	34,000	Dawn	E. Hereford	**$ 23.9713**	12	$ 815,026	**$ 9,780,310**
TransCanada*	29594	FT	No	5,937	Parkway	Iroquois	**$ 10.9029**	12	$ 64,731	**$ 776,768**
Union*	M12205	M12	No	6,003	Dawn	Parkway	**$ 2.1233**	12	$ 12,746	**$ 152,956**
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	W-10	Dawn	$ 4.5625	5	$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Alliance	St. Clair	$ 7.7745	12	$ 47,191	$ 566,295
Vector*	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	**$ 0.3429**	12	$ 2,082	**$ 24,979**

Total Annual Demand Costs $ 32,133,935

*: Reflects revised Canadian exchange rate

**: Support for demand rates is provided in Attachment NUI-FXW-10 of the 2015-2016 Winter Period CGF

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2015 through October 31, 2016

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
AFT-1 (AFT-2)	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	16-100-FT-NN	115,000	39,165	35,529	40,306	34%	31%	35%	$ 2,833,761	$ 965,080	$ 875,484	$ 993,196
Granite	16-100-FT-NN	85,000	39,165	35,529	10,306	46%	42%	12%	$ 1,047,260	$ 482,540	$ 437,742	$ 126,977
Granite	16-100-FT-NN	85,000	39,165	35,529	10,306	46%	42%	12%	$ 1,092,548	$ 503,407	$ 456,672	$ 132,468
Iroquois	R181001	6,569	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	1,100			100%	0%	0%	$ 342,993	$ 342,993	$ -	$ -
PNGTS	1997-004	33,000		33,000		0%	100%	0%	$ 8,146,067	$ -	$ 8,146,067	$ -
Tennessee	5083	4,605	4,605			100%	0%	0%	$ 1,284,032	$ 1,284,032	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,116,443	$ 2,116,443	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 259,998	$ -	$ 259,998	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 121,067	$ 121,067	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 191,675	$ 191,675	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 79,994	$ 79,994	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 367,419	$ 367,419	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 64,987	$ 64,987	$ -	$ -
TransCanada*	33322	34,000		34,000		0%	100%	0%	**$ 9,780,310**	$ -	**$ 9,780,310**	$ -
TransCanada*	29594	5,937	5,937	-		100%	0%	0%	**$ 776,768**	**$ 776,768**	$ -	$ -
Union*	M12205	6,003	6,003	-		100%	0%	0%	**$ 152,956**	**$ 152,956**	$ -	$ -
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%	**$ 24,979**	**$ 24,979**	$ -	$ -
Annual Total Demand Costs									$ 32,133,935	$ 8,968,294	$ 21,913,000	$ 1,252,642

*: Reflects revised Canadian exchange rate

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2015 through October 31, 2016

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
FS-MA	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0205	$ 1.4938	12	Line 1 of Page 3, Att to Sch 5A	$ 63,797	$ 76,058	$ 139,855
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 $ 3,029,855

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2015 through October 31, 2016

Resource	Supplier	Contract Quantity	Maximum Daily Quantity	Months Per Year	Monthly Fixed Charges	Annual Fixed Charges
LNG Contract	[redacted]	125,000	3,000	5	[redacted]	[redacted]
Peaking Contract 1		150,000	10,000	5		
Peaking Contract 2		225,000	15,000	5		
Peaking Contract 3		100,000	5,000	5		
Peaking Contract 4		240,000	12,000	5		
Total Peaking Supply Contract Demand Costs						$ 4,223,000

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2015 through October 31, 2016

Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin Wash 10 via Vector, TCPL, PNGTS AGT K#93201A1C Tennessee Niagara Tennessee Long-Haul	[redacted]
Total Asset Management	$ (9,565,000)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (64,987)
Total Capacity Release	$ (64,987)

Total Asset Management and Capacity Release Revenue	$ (9,629,987)

REDACTED

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for March 4, 2016

Estimated Adders to NYMEX Last Day Settlement

Line	Supply Source	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
1	Chicago	[redacted]					
2	Iroquois Receipts						
3	PNGTS Delivered						
4	PNGTS Delivered (Dec-Feb)						
5	PNGTS Receipts						
6	Maritimes Delivered						
7	Niagara						
8	Tennessee Production (Zone 0)						
9	Tennessee Production (Zone L)						
10	Tennessee Production (Zone 4)						
11	Tenessee Zone 4 Spot						
12	Peaking Contract 1						
13	Peaking Contract 2						
14	Peaking Contract 3						
15	LNG						
16	W10 Supply (Injection)						
17	TGP FS Supply (Injection)						
18	W10 AMA Spot Tier I						
19	W10 AMA Spot Tier II						
20	W10 AMA Additional Spot						
21	AGT Receipts						
22	Spot Supplies						
23	Peaking Contract 4 (Fixed Price)						
24	NYMEX Forecast	$1.79	$1.90	$2.00	$2.05	$2.07	$2.11

Northern Utilities, Inc.
Transportation Contract Rates
November 2015 through October 2016
Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734
3	Granite	FT-NN	N/A	N/A		Page 7, 8	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.1069	$ 4.2845	$ 4.2845	$ 4.2845
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	$ 25.9843	$ 25.9843	$ 25.9843	$ 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	$ 49.3701	$ 49.3701	$ 49.3701	$ 49.3701	$ 49.3701							
7	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362	$ 23.2362
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281	$ 20.6281
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668	$ 8.1668
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756	$ 7.1756
11	Texas Eastern	FT-1/FTS	M3	M3	1	Pages 23, 24	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120	$ 5.6120
12	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504	$ 26.9504
13	TransCanada	FT	Parkway	Iroquois		Page 26	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241	$ 13.4241
14	Union	M12	Dawn	Parkway		Page 26	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759	$ 2.1759
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	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863	$ 0.3863

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
19	Algonquin	AFT-1 (AFT-2)	N/A	N/A	3	Page 5, 46	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
20	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	3	Page 5, 46	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126
21	Granite	FT-NN	N/A	N/A	3	Page 7, 46	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
22	Iroquois	RTS-1	Zone 1	Zone 1	3	Pages 9, 46	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044
23	LNG Trucking		Everett, MA	LNG Plant		Page 13	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900	$ 1.1900
24	PNGTS	FT	N/A	N/A	3	Page 17, 46	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
25	Tennessee	FT-A	Zone 0	Zone 4	3, 4	Page 19, 21, 46	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121	$ 0.3121
26	Tennessee	FT-A	Zone 0	Zone 6	3, 4	Page 19, 21, 46	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643	$ 0.3643
27	Tennessee	FT-A	Zone L	Zone 4	3, 4	Page 19, 21, 46	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651	$ 0.2651
28	Tennessee	FT-A	Zone L	Zone 6	3, 4	Page 19, 21, 46	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173
29	Tennessee	FT-A	Zone 4	Zone 6	3, 4	Page 19, 21, 46	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203
30	Tennessee	FT-A	Zone 5	Zone 6	3, 4	Page 19, 21, 46	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904	$ 0.0904
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	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
35	Vector	FT-1	Alliance	Dawn		Page 37, 46	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
36	Vector	FT-1	W-10 Storage	Dawn		Page 37, 46	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Fuel Rate Support	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
37	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 6	1.07%	0.97%	0.97%	0.97%	0.97%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
38	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 6	1.07%	0.97%	0.97%	0.97%	0.97%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
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	0.32%	0.32%	0.32%	0.32%	0.32%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
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	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%
43	Tennessee	FT-A	Zone 0	Zone 6		Page 21	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%
44	Tennessee	FT-A	Zone L	Zone 4		Page 21	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%
45	Tennessee	FT-A	Zone L	Zone 6		Page 21	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%
46	Tennessee	FT-A	Zone 4	Zone 6		Page 21	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%
47	Tennessee	FT-A	Zone 5	Zone 6		Page 21	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%
48	TransCanada	FT	Dawn	E. Hereford	5	Page 38	2.06%	2.06%	2.06%	2.06%	2.06%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
49	TransCanada	FT	Parkway	Iroquois	5	Page 38	1.04%	1.04%	1.04%	1.04%	1.04%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%
50	Union	M12	Dawn	Parkway		Page 35	1.01%	1.01%	1.01%	1.01%	1.01%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%
51	Vector	FT-1	Alliance	W-10	5	Page 42	0.79%	0.79%	0.79%	0.79%	0.79%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%
52	Vector	FT-1	Alliance	Dawn	5	Page 42	0.79%	0.79%	0.79%	0.79%	0.79%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%
53	Vector	FT-1	W-10 Storage	Dawn	5	Page 42	0.29%	0.29%	0.29%	0.29%	0.29%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%

Note 1 FT-1 Demand Rate = $4.952 plus FT-1 / FTS Rate = $0.66, totals to $5.612
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 2015 through October 2016

Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 20, 22	$ 0.0207	$ 1.4938	$ 0.0087	0.00%	$ 0.0087	0.80%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.3400				
3	W-10	Storage	1	Pages 43, 44, 45			$ -	0.30%	$ -	0.70%

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 2016 through October 2016

Description	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Season
Pipeline Supplies							
Tenn Zone 4 Spot	[redacted]						
Tennessee Production							
Chicago							
Algonquin Receipts							
TGP Zone 6							
Niagara							
Iroquois Receipts							
PNGTS Receipts							
PNGTS Delivered							
PNGTS Delivered (Dec - Feb)							
Maritimes Delivered							
Total Pipeline	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 5,064,105
Company Managed Pipeline	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Pipeline	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 5,064,105
Underground Storage							
Tennessee Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Company Managed Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supplies							
Peaking Contract 1	[redacted]						
Peaking Contract 2							
Peaking Contract 3							
Peaking Contract 4							
LNG							
Total Peaking	$ 20,534	$ 19,907	$ 20,638	$ 20,675	$ 20,119	$ 20,863	$ 122,736
Company Managed Peaking	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Peaking	$ 20,534	$ 19,907	$ 20,638	$ 20,675	$ 20,119	$ 20,863	$ 122,736
Total NUI Commodity	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 5,186,841
Company-Managed (NH & ME)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Service (NH & ME)	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 5,186,841
Net Sales Service	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 5,186,841

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) May 2016 through October 2016							
Description	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Season
Pipeline Supplies							
Tenn Zone 4 Spot	75,194	72,768	75,194	75,194	72,768	75,194	446,312
Tennessee Production	308,702	147,866	110,097	112,646	164,122	318,930	1,162,363
Chicago	0	0	0	0	0	0	0
Algonquin Receipts	0	0	0	0	0	0	0
TGP Zone 6	6,613	0	0	0	0	63,554	70,166
Niagara	17,036	0	0	0	0	39,126	56,162
Iroquois Receipts	0	0	0	0	0	0	0
PNGTS Receipts	30,892	29,895	30,892	30,892	29,895	30,892	183,356
PNGTS Delivered	83,407	80,717	83,407	83,407	80,717	83,407	495,061
PNGTS Delivered	0	0	0	0	0	0	0
Maritimes Delivered	0	0	0	0	0	62,000	62,000
Total Pipeline	521,843	331,246	299,589	302,138	347,502	673,103	2,475,421
Company Managed Pipeline	0	0	0	0	0	0	0
Net Pipeline	521,843	331,246	299,589	302,138	347,502	673,103	2,475,421
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
Peaking Contract 3	0	0	0	0	0	0	0
Peaking Contract 4	0	0	0	0	0	0	0
LNG	2,201	2,130	2,201	2,201	2,130	2,201	13,064
Total Peaking	2,201	2,130	2,201	2,201	2,130	2,201	13,064
Company Managed Peaking	0	0	0	0	0	0	0
Net Peaking	2,201	2,130	2,201	2,201	2,130	2,201	13,064
Total NUI Commodity	524,044	333,376	301,790	304,339	349,632	675,304	2,488,485
Company-Managed (NH & ME)	0	0	0	0	0	0	0
Sales Service (NH & ME)	524,044	333,376	301,790	304,339	349,632	675,304	2,488,485
Net Sales Service	524,044	333,376	301,790	304,339	349,632	675,304	2,488,485

REDACTED

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
May 2016 through October 2016

Description	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Season
Pipeline Supplies							
Tenn Zone 4 Spot	[redacted]						
Tennessee Production							
Chicago							
Algonquin Receipts							
TGP Zone 6							
Niagara							
Iroquois Receipts							
PNGTS Receipts							
PNGTS Delivered							
PNGTS Delivered							
Maritimes Delivered							
Total Pipeline	$ 1.867	$ 1.851	$ 1.897	$ 1.951	$ 2.035	$ 2.394	$ 2.046
Company Managed Pipeline							
Net Pipeline	$ 1.867	$ 1.851	$ 1.897	$ 1.951	$ 2.035	$ 2.394	$ 2.046
Underground Storage							
Tennessee Storage							
Washington 10 Storage							
Total Storage							
Company Managed Storage							
Net Storage							
Peaking Supplies							
Peaking Contract 1	[redacted]						
Peaking Contract 2							
Peaking Contract 3							
Peaking Contract 4							
LNG							
Total Peaking	$ 9.330	$ 9.346	$ 9.376	$ 9.393	$ 9.446	$ 9.479	$ 9.395
Company Managed Peaking							
Net Peaking	$ 9.330	$ 9.346	$ 9.376	$ 9.393	$ 9.446	$ 9.479	$ 9.395
Total NUI Commodity	$ 1.899	$ 1.899	$ 1.951	$ 2.005	$ 2.080	$ 2.417	$ 2.084
Company-Managed (NH & ME)							
Sales Service (NH & ME)	$ 1.899	$ 1.899	$ 1.951	$ 2.005	$ 2.080	$ 2.417	$ 2.084
Net Sales Service	$ 1.899	$ 1.899	$ 1.951	$ 2.005	$ 2.080	$ 2.417	$ 2.084

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 9	76,128	73,672	76,128	76,128	73,672	76,128	451,856
2	City Gate Delivered Volume	Line 37	75,194	72,768	75,194	75,194	72,768	75,194	446,312
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 29 and 39	$ 9,183	$ 8,887	$ 9,183	$ 9,183	$ 8,887	$ 9,183	$ 54,505
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]						
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	76,128	73,672	76,128	76,128	73,672	76,128	451,856
10	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 1.984
11	NYMEX Cost	Line 9 times Line 10	$ 136,041	$ 139,977	$ 151,951	$ 155,758	$ 152,133	$ 160,401	$ 896,261
12	NYMEX Basis Price	Attach to Sched 5A, Line 11 of Page 1	[redacted]						
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]						
14	Total Purchase Price	Line 10 plus Line 12	[redacted]						
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]						
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA 300 Leg								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Total Contract Recevied Volume	Sendout Optimization	76,128	73,672	76,128	76,128	73,672	76,128	451,856
23	Received Volume	Line 14	76,128	73,672	76,128	76,128	73,672	76,128	451,856
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	76,128	73,672	76,128	76,128	73,672	76,128	451,856
26	Fuel Loss Rate	Attach to Sched 5A, Line 46 of Page 2	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%
27	Delivered Volume	Line 25 times (1 - Line 26)	75,458	73,024	75,458	75,458	73,024	75,458	447,879
28	Variable Transportation Rate	Attach to Sched 5A, Line 29 of Page 2	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203
29	Variable Transportation Costs	Line 27 times Line 28	$ 9,078	$ 8,785	$ 9,078	$ 9,078	$ 8,785	$ 9,078	$ 53,880
30									
31	Transportation Segment 3								
32	Granite State Gas Transmission (Contract 14-001-FT-NN)								
33	Receipt Point: Pleasant St.								
34	Delivery Point: Northern City Gates								
35	Received Volume	Line 27	75,458	73,024	75,458	75,458	73,024	75,458	447,879
36	Fuel Loss Rate	Attach to Sched 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)	75,194	72,768	75,194	75,194	72,768	75,194	446,312
38	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
39	Variable Transportation Costs	Line 37 times Line 38	$ 105	$ 102	$ 105	$ 105	$ 102	$ 105	$ 625

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
2	City Gate Volumes - Z0	Line 2 of Page 5	10,201	-	-	-	-	13,935	24,136
3	City Gate Volumes - Z1	Line 2 of Page 6	191,333	44,155	2,928	5,477	60,411	197,826	502,129
4	City Gate Volumes - Z4	Line 2 of Page 7	107,169	103,712	107,169	107,169	103,712	107,169	636,099
5	Total City Gate Volumes	Sum Lines 1 through 3	308,702	147,866	110,097	112,646	164,122	318,930	1,162,363
6	City Gate Delivered Costs - Z0	Line 6 of Page 5	[redacted]						
7	City Gate Delivered Costs - Z1	Line 6 of Page 6							
8	City Gate Delivered Costs - Z4	Line 5 of Page 7							
9	Total City Gate Delivered Costs	Sum Lines 5 through 7							
10	Average Delivered Price	Line 8 divided by Line 4							

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-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 9	108,500	105,000	108,500	108,500	105,000	108,500	644,000
2	City Gate Delivered Volume	Line 34	107,169	103,712	107,169	107,169	103,712	107,169	636,099
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 13,088	$ 12,666	$ 13,088	$ 13,088	$ 12,666	$ 13,088	$ 77,682
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	108,500	105,000	108,500	108,500	105,000	108,500	644,000
10	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 1.984
11	NYMEX Cost	Line 9 times Line 10	$ 193,890	$ 199,500	$ 216,566	$ 221,991	$ 216,825	$ 228,610	$ 1,277,381
12	NYMEX Basis Price	Attach to Sched 5A, Line 10 of Page 1	[redacted]						
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 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	108,500	105,000	108,500	108,500	105,000	108,500	644,000
23	Fuel Loss Rate	Attach to Sched 5A, Line 46 of Page 2	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%
24	Delivered Volume	Line 22 times (1 - Line 23)	107,545	104,076	107,545	107,545	104,076	107,545	638,333
25	Variable Transportation Rate	Attach to Sched 5A, Line 29 of Page 2	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203	$ 0.1203
26	Variable Transportation Costs	Line 24 times Line 25	$ 12,938	$ 12,520	$ 12,938	$ 12,938	$ 12,520	$ 12,938	$ 76,791
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 14-001-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	107,545	104,076	107,545	107,545	104,076	107,545	638,333
33	Fuel Loss Rate	Attach to Sched 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)	107,169	103,712	107,169	107,169	103,712	107,169	636,099
35	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
36	Variable Transportation Costs	Line 34 times Line 35	$ 150	$ 145	$ 150	$ 150	$ 145	$ 150	$ 891

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 23	10,519	-	-	-	-	14,369	24,888
2	City Gate Delivered Volume	Line 35	10,201	-	-	-	-	13,935	24,136
3	Total Purchase Price	Line 15	[redacted]						
4	Total Purchase Cost	Line 2 times Line 3							
5	Variable Transportation Costs	Sum Lines 27 and 37	$ 3,744	$ -	$ -	$ -	$ -	$ 5,114	$ 8,857
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]						
7	Average Delivered Price	Line 6 divided by Line 2							
8									
9	Tennessee Zone 0 Supply Costs								
10	Purchased Volumes	Sendout Optimization	10,519	-	-	-	-	14,369	24,888
11	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 1.972
12	NYMEX Cost	Line 9 times Line 10	$ 18,797	$ -	$ -	$ -	$ -	$ 30,276	$ 49,073
13	NYMEX Basis Price	Attach to Sched 5A, Line 8 of Page 1	[redacted]						
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	Transportation Fuel Losses and Variable Charges								
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	10,519	-	-	-	-	14,369	24,888
24	Fuel Loss Rate	Attach to Sched 5A, Line 43 of Page 2	2.68%					2.68%	2.68%
25	Delivered Volume	Line 23 times (1 - Line 24)	10,237	-	-	-	-	13,984	24,221
26	Variable Transportation Rate	Attach to Sched 5A, Line 26 of Page 2	$ 0.3643					$ 0.3643	$ 0.3643
27	Variable Transportation Costs	Line 25 times Line 26	$ 3,729	$ -	$ -	$ -	$ -	$ 5,094	$ 8,824
28									
29	Transportation Segment 2A								
30	Granite State Gas Transmission (Contract 14-001-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	10,237	-	-	-	-	13,984	24,221
34	Fuel Loss Rate	Attach to Sched 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)	10,201	-	-	-	-	13,935	24,136
36	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
37	Variable Transportation Costs	Line 35 times Line 36	$ 14	$ -	$ -	$ -	$ -	$ 20	$ 34

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 23	196,645	45,381	3,009	5,629	62,088	203,320	516,072
2	City Gate Delivered Volume	Line 35	191,333	44,155	2,928	5,477	60,411	197,826	502,129
3	Total Purchase Price	Line 15	[redacted]						
4	Total Purchase Cost	Line 2 times Line 3	[redacted]						
5	Variable Transportation Costs	Sum Lines 27 and 37	$ 61,191	$ 14,121	$ 936	$ 1,752	$ 19,320	$ 63,268	$ 160,588
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]						
7	Average Delivered Price	Line 6 divided by Line 2	[redacted]						
8									
9	<u>Tennessee Zone L Supply Costs</u>								
10	Purchased Volumes	Sendout Optimization	196,645	45,381	3,009	5,629	62,088	203,320	516,072
11	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 1.960
12	NYMEX Cost	Line 9 times Line 10	$ 351,405	$ 86,223	$ 6,006	$ 11,517	$ 128,212	$ 428,394	$ 1,011,757
13	NYMEX Basis Price	Attach to Sched 5A, Line 9 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]						
15	Total Purchase Price	Line 10 plus Line 12	[redacted]						
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]						
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	196,645	45,381	3,009	5,629	62,088	203,320	516,072
24	Fuel Loss Rate	Attach to Sched 5A, Line 45 of Page 2	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%
25	Delivered Volume	Line 23 times (1 - Line 24)	192,005	44,310	2,938	5,496	60,623	198,521	503,892
26	Variable Transportation Rate	Attach to Sched 5A, Line 28 of Page 2	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173	$ 0.3173
27	Variable Transportation Costs	Line 25 times Line 26	$ 60,923	$ 14,059	$ 932	$ 1,744	$ 19,236	$ 62,991	$ 159,885
28									
29	Transportation Segment 2B								
30	Granite State Gas Transmission (Contract 14-001-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	192,005	44,310	2,938	5,496	60,623	198,521	503,892
34	Fuel Loss Rate	Attach to Sched 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)	191,333	44,155	2,928	5,477	60,411	197,826	502,129
36	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
37	Variable Transportation Costs	Line 35 times Line 36	$ 268	$ 62	$ 4	$ 8	$ 85	$ 277	$ 703

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-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
2	Purchased Volumes	Line 9	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Sum Lines 68, 88 and 108	-	-	-	-	-	-	-
4	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 27, 47, 60, 70, 80, 90, 100 and 110	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 5 divided by Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8									
9	Chicago Supply Costs								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
11	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price	Attach to Sched 5A, Line 1 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	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	-	-	-	-	-	-	-
24	Fuel Loss Rate	Attach to Sched 5A, Line 52 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Attach to Sched 5A, Line 35 of Page 2							
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
34	Fuel Loss Rate	Attach to Sched 5A, Line 50 of Page 2							
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Attach to Sched 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	-	-	-	-	-	-	-
44	Fuel Loss Rate	Attach to Sched 5A, Line 49 of Page 2							
45	Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	-	-	-	-
46	Variable Transportation Rate	Attach to Sched 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	-	-	-	-	-	-	-
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	Received Volume	Line 45	-	-	-	-	-	-	-
57	Fuel Loss Rate	Attach to Sched 5A, Line 40 of Page 2							
58	Delivered Volume	Line 56 times (1 - Line 57)	-	-	-	-	-	-	-
59	Variable Transportation Rate	Attach to Sched 5A, Line 22 of Page 2							
60	Variable Transportation Costs	Line 58 times Line 59	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
67	Fuel Loss Rate	Attach to Sched 5A, Line 47 of Page 2							
68	City Gate Delivered Volume	Line 66 times (1 - Line 67)	-	-	-	-	-	-	-
69	Variable Transportation Rate	Attach to Sched 5A, Line 30 of Page 2							
70	Variable Transportation Costs	Line 68 times Line 69	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	Attach to Sched 5A, Line 47 of Page 2							
78	Delivered Volume	Line 76 times (1 - Line 77)	-	-	-	-	-	-	-
79	Variable Transportation Rate	Attach to Sched 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 14-001-FT-NN)								
84	Receipt Point: Pleasant St.								
85	Delivery Point: Northern City Gates								
86	Received Volume	Line 78	-	-	-	-	-	-	-
87	Fuel Loss Rate	Attach to Sched 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	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	
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	Attach to Sched 5A, Line 47 of Page 2							
98	Delivered Volume	Line 96 times (1 - Line 97)	-	-	-	-	-	-	-
99	Variable Transportation Rate	Attach to Sched 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	Attach to Sched 5A, Line 37 of Page 2							
108	City Gate Delivered Volume	Line 106 times (1 - Line 107)	-	-	-	-	-	-	-
109	Variable Transportation Rate	Attach to Sched 5A, Line 19 of Page 2							
110	Variable Transportation Costs	Line 108 times Line 109	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 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	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Attach to Sched 5A, Line 21 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	Attach to Sched 5A, Line 38 of Page 2							1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Attach to Sched 5A, Line 20 of Page 2							
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 9	6,636	-	-	-	-	63,777	70,413
2	City Gate Delivered Volume	Line 24	6,613	-	-	-	-	63,554	70,166
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Line 26	$ 9	$ -	$ -	$ -	$ -	$ 89	$ 98
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Tennessee Zone 6 Supply								
9	Purchased Volumes	Sendout Optimization	6,636	-	-	-	-	63,777	70,413
10	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 2.077
11	NYMEX Cost	Line 9 times Line 10	$ 11,858	$ -	$ -	$ -	$ -	$ 134,378	$ 146,236
12	NYMEX Basis Price	Attach to Sched 5A, Line 22 of Page 1	[redacted]						
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 14-001-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	6,636	-	-	-	-	63,777	70,413
23	Fuel Loss Rate	Attach to Sched 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	6,613	-	-	-	-	63,554	70,166
25	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
26	Variable Transportation Costs	Line 24 times Line 25	$ 9	$ -	$ -	$ -	$ -	$ 89	$ 98

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-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
2	Purchased Volumes	Line 9	17,216	-	-	-	-	39,541	56,757
3	City Gate Delivered Volume	Line 45	17,036	-	-	-	-	39,126	56,162
4	Total Purchase Cost	Line 15	[redacted]						
5	Variable Transportation Costs	Sum Lines 27, 37 and 47	$ 1,569	$ -	$ -	$ -	$ -	$ 3,604	$ 5,174
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
7	Average Delivered Price	Line 5 divided by Line 2	[redacted]						
8									
9	Niagara Supply Costs								
10	Purchased Volumes	Sendout Optimization	17,216	-	-	-	-	39,541	56,757
11	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 2.010
12	NYMEX Cost	Line 9 times Line 10	$ 30,765	$ -	$ -	$ -	$ -	$ 83,312	$ 114,077
13	NYMEX Basis Price	Attach to Sched 5A, Line 7 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]						
15	Total Purchase Price	Line 10 plus Line 12	[redacted]						
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]						
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	8,048	-	-	-	-	23,376	31,424
24	Fuel Loss Rate	Attach to Sched 5A, Line 47 of Page 2	0.70%					0.70%	0.70%
25	Delivered Volume	Line 23 times (1 - Line 24)	7,992	-	-	-	-	23,212	31,204
26	Variable Transportation Rate	Attach to Sched 5A, Line 30 of Page 2	$ 0.0904					$ 0.0904	$ 0.0904
27	Variable Transportation Costs	Line 25 times Line 26	$ 722	$ -	$ -	$ -	$ -	$ 2,098	$ 2,821
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	9,168	-	-	-	-	16,165	25,333
34	Fuel Loss Rate	Attach to Sched 5A, Line 47 of Page 2	0.70%					0.70%	0.70%
35	Delivered Volume	Line 33 times (1 - Line 34)	9,104	-	-	-	-	16,052	25,155
36	Variable Transportation Rate	Attach to Sched 5A, Line 30 of Page 2	$ 0.0904					$ 0.0904	$ 0.0904
37	Variable Transportation Costs	Line 35 times Line 36	$ 823	$ -	$ -	$ -	$ -	$ 1,451	$ 2,274
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 14-001-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	17,095	-	-	-	-	39,264	56,359
44	Fuel Loss Rate	Attach to Sched 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)	17,036	-	-	-	-	39,126	56,162
46	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
47	Variable Transportation Costs	Line 45 times Line 46	$ 24	$ -	$ -	$ -	$ -	$ 55	$ 79

REDACTED

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-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 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	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price	Attach to Sched 5A, Line 2 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	-	-	-	-	-	-	-
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%	
26	Received Volume	Line 15	-	-	-	-	-	-	-
27	Fuel Loss Rate	Attach to Sched 5A, Line 40 of Page 2							
28	Delivered Volume	Line 26 times (1 - Line 27)	-	-	-	-	-	-	-
29	Variable Transportation Rate	Attach to Sched 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	Attach to Sched 5A, Line 47 of Page 2							
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	-	-	-	-	-	-	-
39	Variable Transportation Rate	Attach to Sched 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	Attach to Sched 5A, Line 47 of Page 2							
48	Delivered Volume	Line 46 times (1 - Line 47)	-	-	-	-	-	-	-
49	Variable Transportation Rate	Attach to Sched 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 14-001-FT-NN)								
54	Receipt Point: Pleasant St.								
55	Delivery Point: Northern City Gates								
56	Received Volume	Line 48	-	-	-	-	-	-	-
57	Fuel Loss Rate	Attach to Sched 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	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	
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	Attach to Sched 5A, Line 47 of Page 2							
68	Delivered Volume	Line 66 times (1 - Line 67)	-	-	-	-	-	-	-
69	Variable Transportation Rate	Attach to Sched 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	Attach to Sched 5A, Line 37 of Page 2							
78	City Gate Delivered Volume	Line 76 times (1 - Line 77)	-	-	-	-	-	-	-
79	Variable Transportation Rate	Attach to Sched 5A, Line 19 of Page 2							
80	Variable Transportation Costs	Line 78 times Line 79	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

Source of Supply: PNGTS (Pittsburg, NH)
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 9	31,000	30,000	31,000	31,000	30,000	31,000	184,000
2	City Gate Delivered Volume	Line 34	30,892	29,895	30,892	30,892	29,895	30,892	183,356
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 87	$ 84	$ 87	$ 87	$ 84	$ 87	$ 514
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	31,000	30,000	31,000	31,000	30,000	31,000	184,000
10	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 1.984
11	NYMEX Cost	Line 9 times Line 10	$ 55,397	$ 57,000	$ 61,876	$ 63,426	$ 61,950	$ 65,317	$ 364,966
12	NYMEX Basis Price	Attach to Sched 5A, Line 5 of Page 1	[redacted]						
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	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	31,000	30,000	31,000	31,000	30,000	31,000	184,000
23	Fuel Loss Rate	Attach to Sched 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	31,000	30,000	31,000	31,000	30,000	31,000	184,000
25	Variable Transportation Rate	Attach to Sched 5A, Line 24 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
26	Variable Transportation Costs	Line 24 times Line 25	$ 43	$ 42	$ 43	$ 43	$ 42	$ 43	$ 258
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 14-001-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	31,000	30,000	31,000	31,000	30,000	31,000	184,000
33	Fuel Loss Rate	Attach to Sched 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)	30,892	29,895	30,892	30,892	29,895	30,892	183,356
35	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
36	Variable Transportation Costs	Line 34 times Line 35	$ 43	$ 42	$ 43	$ 43	$ 42	$ 43	$ 257

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 9	-	-	-	-	-	62,000	62,000
2	City Gate Delivered Volume	Line 1	-	-	-	-	-	62,000	62,000
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Maritimes Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	62,000	62,000
10	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 2.107
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 130,634	$ 130,634
12	NYMEX Basis Price	Attach to Sched 5A, Line 6 of Page 1	[redacted]						
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							

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Purchased Volumes	Line 9	83,700	81,000	83,700	83,700	81,000	83,700	496,800
2	City Gate Delivered Volume	Line 24	83,407	80,717	83,407	83,407	80,717	83,407	495,061
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Line 26	$ 117	$ 113	$ 117	$ 117	$ 113	$ 117	$ 693
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	83,700	81,000	83,700	83,700	81,000	83,700	496,800
10	Monthly NYMEX Price	Attach to Sched 5A, Line 24 of Page 1	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107	$ 1.984
11	NYMEX Cost	Line 9 times Line 10	$ 149,572	$ 153,900	$ 167,065	$ 171,250	$ 167,265	$ 176,356	$ 985,408
12	NYMEX Basis Price	Attach to Sched 5A, Line 3 of Page 1	[redacted]						
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 14-001-FT-NN)								
20	Receipt Point: Granite (Westbrook)								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	83,700	81,000	83,700	83,700	81,000	83,700	496,800
23	Fuel Loss Rate	Attach to Sched 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	83,407	80,717	83,407	83,407	80,717	83,407	495,061
25	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
26	Variable Transportation Costs	Line 24 times Line 25	$ 117	$ 113	$ 117	$ 117	$ 113	$ 117	$ 693

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 71	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 27, 37, 50, 63 and 73	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	Attach to Sched 5A, Line 3 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	Schedule 14							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Attach to Sched 5A, Line 3 of Page 3 times Line 9	-	-	-	-	-	-	-
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	Attach to Sched 5A, Line 53 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Attach to Sched 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	Attach to Sched 5A, Line 53 of Page 2							
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Attach to Sched 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 32	-	-	-	-	-	-	-
			-	-	-	-	-	-	
			0%	0%	0%	0%	0%	0%	
46	Received Volume	Line 35	-	-	-	-	-	-	-
47	Fuel Loss Rate	Attach to Sched 5A, Line 48 of Page 2							
48	Delivered Volume	Line 46 times (1 - Line 47)	-	-	-	-	-	-	-
49	Variable Transportation Rate	Attach to Sched 5A, Line 31 of Page 2							
50	Variable Transportation Costs	Line 48 times Line 49	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51									
52	Transportation Segment 4								
53	PNGTS (Contract 1997-004)								
54	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
55	Delivery Point: Granite (Westbrook, Newington, Eliot)								
56	Total Contract Recevied Volume	Sendout Optimization	-	-	-	-	-	-	-
57	Received Volume	Line 48	-	-	-	-	-	-	
58	Percentage Allocated	Line 57 divided by Line 56	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
59	Total Contract Recevied Volume	Sendout Optimization							
60	Fuel Loss Rate	Attach to Sched 5A, Line 41 of Page 2							
61	Delivered Volume	Line 59 times (1 - Line 60)	-	-	-	-	-	-	-
62	Variable Transportation Rate	Attach to Sched 5A, Line 24 of Page 2							
63	Variable Transportation Costs	Line 61 times Line 62	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64									
65	Transportation Segment 5								
66	Granite State Gas Transmission (Contract 14-001-FT-NN)								
67	Receipt Point: Westbrook, Newington, Eliot								
68	Delivery Point: Northern City Gates								
69	Received Volume	Line 61	-	-	-	-	-	-	-
70	Fuel Loss Rate	Attach to Sched 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
71	City Gate Delivered Volume	Line 69 times (1 - Line 70)	-	-	-	-	-	-	-
72	Variable Transportation Rate	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	
73	Variable Transportation Costs	Line 71 times Line 72	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

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

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 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	Attach to Sched 5A, Line 1 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	Schedule 14							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Attach to Sched 5A, Line 1 of Page 3 times Line 9	-	-	-	-	-	-	-
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							
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	Attach to Sched 5A, Line 46 of Page 2							
28	Delivered Volume	Line 26 times (1 - Line 27)	-	-	-	-	-	-	-
29	Variable Transportation Rate	Attach to Sched 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 14-001-FT-NN)								
34	Receipt Point: Pleasant St.								
35	Delivery Point: Northern City Gates								
36	Received Volume	Line 28	-	-	-	-	-	-	-
37	Fuel Loss Rate	Attach to Sched 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	Attach to Sched 5A, Line 21 of Page 2	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	
40	Variable Transportation Costs	Line 38 times Line 39	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	2016 Summer
1	Gross Withdrawn Volume	Line 9	2,201	2,130	2,201	2,201	2,130	2,201	13,064
2	City Gate Delivered Volume	Line 15	2,201	2,130	2,201	2,201	2,130	2,201	13,064
3	Total Withdrawal Costs	Line 16	[redacted]						
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	2,201	2,130	2,201	2,201	2,130	2,201	13,064
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	Schedule 14	[redacted]						
13	Withdrawn Inventory Value	Line 9 times Line 12							
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	2,201	2,130	2,201	2,201	2,130	2,201	13,064
16	Total Withdrawal Costs	Line 11 plus Line 13	[redacted]						

Schedule 7

Provided in Winter 2015–16 Cost-of-Gas Filing

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 783 therms/year

Comparison of Summer 2016 vs. Summer 2015

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)		59	100	140	142	118	80	639	49	25	16	14	15	25	144	783
Winter 2015- 2016																
Customer Charge units @	$21.36	$21.36	$21.36	$21.36	$21.36	$21.36	$21.36	$128.16								
First 50 units @	$0.6239	$31.20	$31.20	$31.20	$31.20	$31.20	$31.20	$187.17								
Over 50 units @	$0.5103	$4.39	$25.45	$45.97	$46.77	$34.80	$15.55	$172.92								
COG 1	$0.6570	$38.50						$38.50								
COG 2	$0.6052		$60.45					$60.45								
COG 3	$0.6052			$84.77				$84.77								
COG 4	$0.6676				$94.56			$94.56								
COG 5	$0.6676					$78.91		$78.91								
COG 6	$0.6676						$53.72	$53.72								
Winter Period 2015-2016 Avg. COG	$0.6432 *															
LDAC	$0.0374	$2.19	$3.74	$5.24	$5.30	$4.42	$3.01	$23.89								
Summer 2016																
Customer Charge units @	$21.36								$21.36	$21.36	$21.36	$21.36	$21.36	$21.36	$128.16	
First 50 units @	$0.5449								$26.52	$13.42	$8.90	$7.72	$8.36	$13.73	$78.64	
Over 50 units @	$0.5449								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
COG 1	$0.3196								$15.55						$15.55	
COG 2	$0.3196									$7.87					$7.87	
COG 3	$0.3196										$5.22				$5.22	
COG 4	$0.3196											$4.53			$4.53	
COG 5	$0.3196												$4.90		$4.90	
COG 6	$0.3196													$8.05	$8.05	
Summer Period 2016 Avg. COG	$0.3196 *															
LDAC	$0.0374								$1.82	$0.92	$0.61	$0.53	$0.57	$0.94	$5.40	
TOTAL		$97.63	$142.19	$188.53	$199.18	$170.69	$124.83	$923.06	$65.25	$43.57	$36.09	$34.13	$35.19	$44.09	$258.32	$1,181.38

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms (1)		59	100	140	142	118	80	639	49	25	16	14	15	25	144	783
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	$4.11	$23.84	$43.06	$43.81	$32.60	$14.56	$161.98								
COG 1	$1.1069	$64.86						$64.86								
COG 2	$1.1069		$110.56					$110.56								
COG 3	$1.0574			$148.12				$148.12								
COG 4	$0.9644				$136.60			$136.60								
COG 5	$0.9644					$113.99		$113.99								
COG 6	$0.6373						$51.28	$51.28								
Winter Period 2014-2015 Avg. COG	$0.9789 *															
LDAC	$0.0649	$3.80	$6.48	$9.09	$9.19	$7.67	$5.22	$41.46								
Summer 2015																
Customer Charge units @	$21.36								$21.36	$21.36	$21.36	$21.36	$21.36	$21.36	$128.16	
First 50 units @	$0.5449								$26.52	$13.42	$8.90	$7.72	$8.36	$13.73	$78.64	
Over 50 units @	$0.5449								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
COG 1	$0.3238								$15.76						$15.76	
COG 2	$0.3238									$7.97					$7.97	
COG 3	$0.2678										$4.37				$4.37	
COG 4	$0.2678											$3.79			$3.79	
COG 5	$0.2678												$4.11		$4.11	
COG 6	$0.2678													$6.75	$6.75	
Summer Period 2015 Avg. COG	$0.2962 *															
LDAC	$0.0446								$2.17	$1.10	$0.73	$0.63	$0.68	$1.12	$6.44	
TOTAL		$122.01	$190.11	$249.49	$238.83	$203.49	$120.30	$1,124.23	$65.81	$43.85	$35.36	$33.50	$34.51	$42.96	$255.99	$1,380.22
Change		-$24.37	-$47.92	-$60.96	-$39.65	-$32.80	$4.53	-$201.17	-$0.55	-$0.28	$0.73	$0.63	$0.68	$1.12	$2.33	($198.84)
% Chg		-19.98%	-25.21%	-24.43%	-16.60%	-16.12%	3.77%	-17.89%	-0.84%	-0.64%	2.06%	1.89%	1.98%	2.62%	0.91%	-14.41%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2014 to October 2015

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 2,044 therms/year

Comparison of Summer 2016 vs. Summer 2015

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)		143	267	397	406	337	204	1,754	112	47	29	25	28	48	290	2,044
Winter 2015- 2016																
Customer Charge units @	$67.45	$67.45	$67.45	$67.45	$67.45	$67.45	$67.45	$404.70								
First 75 units @	$0.1615	$12.11	$12.11	$12.11	$12.11	$12.11	$12.11	$72.68								
Over 75 units @	$0.1615	$11.02	$31.01	$51.93	$53.44	$42.34	$20.86	$210.61								
COG 1	$0.6616	$94.78						$94.78								
COG 2	$0.6616		$176.66					$176.66								
COG 3	$0.6616			$262.36				$262.36								
COG 4	$0.6676				$270.96			$270.96								
COG 5	$0.6676					$225.11		$225.11								
COG 6	$0.6676						$136.30	$136.30								
Winter Period 2015-2016 Avg. COG	$0.6648*															
LDAC	$0.0223	$3.19	$5.95	$8.84	$9.05	$7.52	$4.55	$39.12								
Summer 2016																
Customer Charge units @	$67.45								$67.45	$67.45	$67.45	$67.45	$67.45	$67.45	$404.70	
First 75 units @	$0.1615								$12.11	$7.66	$4.72	$4.08	$4.57	$7.71	$40.85	
Over 75 units @	$0.1615								$5.98	$0.00	$0.00	$0.00	$0.00	$0.00	$5.98	
COG 1	$0.3619								$40.54						$40.54	
COG 2	$0.3619									$17.16					$17.16	
COG 3	$0.3619										$10.58				$10.58	
COG 4	$0.3619											$9.13			$9.13	
COG 5	$0.3619												$10.24		$10.24	
COG 6	$0.3619													$17.29	$17.29	
Summer Period 2016 Avg. COG	$0.3619*															
LDAC	$0.0223								$2.50	$1.06	$0.65	$0.56	$0.63	$1.07	$6.47	
TOTAL		$188.56	$293.19	$402.69	$413.01	$354.53	$241.28	$1,893.27	$128.59	$93.33	$83.40	$81.22	$82.90	$93.51	$562.95	$2,456.22

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)		143	267	397	406	337	204	1,754	112	47	29	25	28	48	290	2,044
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	$10.33	$29.05	$48.65	$50.06	$39.67	$19.54	$197.31								
COG 1	$1.1217	$160.70						$160.70								
COG 2	$1.1217		$299.51					$299.51								
COG 3	$1.0722			$425.18				$425.18								
COG 4	$0.9792				$397.44			$397.44								
COG 5	$0.9792					$330.18		$330.18								
COG 6	$0.6521						$133.14	$133.14								
Winter Period 2014-2015 Avg. COG	$0.9955*															
LDAC	$0.0437	$6.26	$11.67	$17.33	$17.74	$14.74	$8.92	$76.65								
Summer 2015																
Customer Charge units @	$67.45								$67.45	$67.45	$67.45	$67.45	$67.45	$67.45	$404.70	
First 75 units @	$0.1615								$12.11	$7.66	$4.72	$4.08	$4.57	$7.71	$40.85	
Over 75 units @	$0.1615								$5.98	$0.00	$0.00	$0.00	$0.00	$0.00	$5.98	
COG 1	$0.3297								$36.94						$36.94	
COG 2	$0.3297									$15.64					$15.64	
COG 3	$0.2737										$8.00				$8.00	
COG 4	$0.2737											$6.91			$6.91	
COG 5	$0.2737												$7.75		$7.75	
COG 6	$0.2737													$13.07	$13.07	
Summer Period 2015 Avg. COG	$0.3045*															
LDAC	$0.0234								$2.62	$1.11	$0.68	$0.59	$0.66	$1.12	$6.79	
TOTAL		$251.81	$414.76	$565.69	$539.76	$459.11	$236.13	$2,467.26	$125.10	$91.86	$80.85	$79.02	$80.43	$89.35	$546.62	$3,013.88
Change		-$63.25	-$121.57	-$163.00	-$126.75	-$104.58	$5.15	-$573.99	$3.48	$1.47	$2.55	$2.20	$2.47	$4.16	$16.33	($557.67)
% Chg		-25.12%	-29.31%	-28.81%	-23.48%	-22.78%	2.18%	-23.26%	2.79%	1.61%	3.15%	2.78%	3.07%	4.66%	2.99%	-18.50%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2014 to October 2015

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 22,598 therms/year

Comparison of Summer 2016 vs. Summer 2015

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,789	2,850	4,234	4,007	3,552	2,318	18,750	1,392	666	410	336	389	655	3,849	22,598
Winter 2015- 2016																	
Customer Charge	units @	$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38								
All	units @	$0.2098	$375.40	$597.87	$888.26	$840.77	$745.16	$486.23	$3,933.67								
	COG 1	$1.1217	$2,007.08						$2,007.08								
	COG 2	$1.0722		$3,055.46					$3,055.46								
	COG 3	$1.0722			$4,539.51				$4,539.51								
	COG 4	$1.0722				$4,296.80			$4,296.80								
	COG 5	$1.0722					$3,808.18		$3,808.18								
	COG 6	$1.0722						$2,484.91	$2,484.91								
Winter Period 2015-2016 Avg. COG		$1.0769 *															
	LDAC	$0.0437	$78.19	$124.53	$185.02	$175.13	$155.21	$101.28	$819.36								
Summer 2016																	
Customer Charge	units @	$196.73								$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38	
All	units @	$0.1622								$225.78	$108.06	$66.47	$54.55	$63.11	$106.30	$624.28	
	COG 1	$0.3619								$503.77						$503.77	
	COG 2	$0.3619									$241.11					$241.11	
	COG 3	$0.3619										$148.31				$148.31	
	COG 4	$0.3619											$121.71			$121.71	
	COG 5	$0.3619												$140.82		$140.82	
	COG 6	$0.3619													$237.18	$237.18	
Summer Period 2016 Avg. COG		$0.3619 *															
	LDAC	$0.0234								$32.57	$15.59	$9.59	$7.87	$9.11	$15.34	$90.06	
		TOTAL	$2,657.40	$3,974.59	$5,809.51	$5,509.42	$4,905.27	$3,269.14	$26,125.34	$958.85	$561.49	$421.10	$380.86	$409.77	$555.55	$3,287.62	$29,412.96

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,789	2,850	4,234	4,007	3,552	2,318	18,750	1,392	666	410	336	389	655	3,849	22,598
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	$351.60	$559.97	$831.95	$787.47	$697.92	$455.40	$3,684.30								
	COG 1	$1.1217	$2,007.08						$2,007.08								
	COG 2	$1.1217		$3,196.52					$3,196.52								
	COG 3	$1.0722			$4,539.51				$4,539.51								
	COG 4	$0.9792				$3,924.11			$3,924.11								
	COG 5	$0.9792					$3,477.87		$3,477.87								
	COG 6	$0.6521						$1,511.29	$1,511.29								
Winter Period 2014-2015 Avg. COG		$0.9950 *															
	LDAC	$0.0437	$78.19	$124.53	$185.02	$175.13	$155.21	$101.28	$819.36								
Summer 2015																	
Customer Charge	units @	$196.73								$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38	
All	units @	$0.1622								$225.78	$108.06	$66.47	$54.55	$63.11	$106.30	$624.28	
	COG 1	$0.3297								$458.94						$458.94	
	COG 2	$0.3297									$219.65					$219.65	
	COG 3	$0.2737										$112.16				$112.16	
	COG 4	$0.2737											$92.05			$92.05	
	COG 5	$0.2737												$106.50		$106.50	
	COG 6	$0.2737													$179.38	$179.38	
Summer Period 2015 Avg. COG		$0.3036 *															
	LDAC	$0.0234								$32.57	$15.59	$9.59	$7.87	$9.11	$15.34	$90.06	
		TOTAL	$2,621.13	$4,065.28	$5,740.73	$5,070.96	$4,515.25	$2,252.23	$24,265.59	$914.03	$540.04	$384.95	$351.19	$375.45	$497.75	$3,063.41	$27,329.00
		Change	$36.27	-$90.69	$68.78	$438.46	$390.02	$1,016.91	$1,859.75	$44.82	$21.45	$36.14	$29.66	$34.32	$57.80	$224.21	$2,083.96
		% Chg	1.38%	-2.23%	1.20%	8.65%	8.64%	45.15%	7.66%	4.90%	3.97%	9.39%	8.45%	9.14%	11.61%	7.32%	7.63%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2014 to October 2015

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 20,134 therms/year

Comparison of Summer 2016 vs. Summer 2015

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)		1,657	1,826	2,278	2,323	2,131	1,739	11,955	1,591	1,351	1,291	1,270	1,263	1,414	8,179	20,134
Winter 2015- 2016																
Customer Charge units @	$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38								
First 1,300 units @	$0.1520	$197.60	$197.60	$197.60	$197.60	$197.60	$197.60	$1,185.60								
Over 1,300 units @	$0.1238	$44.19	$65.18	$121.09	$126.68	$102.83	$54.36	$514.33								
COG 1	$0.6462	$1,070.73						$1,070.73								
COG 2	$0.5944		$1,085.66					$1,085.66								
COG 3	$0.5944			$1,354.12				$1,354.12								
COG 4	$0.6568				$1,525.94			$1,525.94								
COG 5	$0.6568					$1,399.38		$1,399.38								
COG 6	$0.6568						$1,142.22	$1,142.22								
Winter Period 2015-2016 Avg. COG	$0.6339 *															
LDAC	$0.0223	$36.95	$40.73	$50.80	$51.81	$47.51	$38.78	$266.59								
Summer 2016																
Customer Charge units @	$196.73								$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38	
First 1,000 units @	$0.1183								$118.30	$118.30	$118.30	$118.30	$118.30	$118.30	$709.80	
Over 1,000 units @	$0.0958								$56.58	$33.60	$27.92	$25.82	$25.18	$39.69	$208.79	
COG 1	$0.2832								$450.47						$450.47	
COG 2	$0.2832									$382.52					$382.52	
COG 3	$0.2832										$365.73				$365.73	
COG 4	$0.2832											$359.54			$359.54	
COG 5	$0.2832												$357.63		$357.63	
COG 6	$0.2832													$400.52	$400.52	
Summer Period 2016 Avg. COG	$0.2832 *															
LDAC	$0.0234								$37.22	$31.61	$30.22	$29.71	$29.55	$33.09	$191.40	
TOTAL		$1,546.20	$1,585.90	$1,920.35	$2,098.77	$1,944.06	$1,629.69	$10,724.96	$859.30	$762.76	$738.90	$730.10	$727.39	$788.34	$4,606.79	$15,331.75

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)		1,657	1,826	2,278	2,323	2,131	1,739	11,955	1,591	1,351	1,291	1,270	1,263	1,414	8,179	20,134
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	$41.41	$61.07	$113.46	$118.70	$96.35	$50.93	$481.93								
COG 1	$1.0063	$1,667.41						$1,667.41								
COG 2	$1.0063		$1,837.99					$1,837.99								
COG 3	$0.9568			$2,179.72				$2,179.72								
COG 4	$0.8638				$2,006.87			$2,006.87								
COG 5	$0.8638					$1,840.42		$1,840.42								
COG 6	$0.5367						$933.36	$933.36								
Winter Period 2014-2015 Avg. COG	$0.8755 *															
LDAC	$0.0437	$72.41	$79.82	$99.55	$101.53	$93.11	$76.00	$522.41								
Summer 2015																
Customer Charge units @	$196.73								$196.73	$196.73	$196.73	$196.73	$196.73	$196.73	$1,180.38	
First 1,000 units @	$0.1183								$118.30	$118.30	$118.30	$118.30	$118.30	$118.30	$709.80	
Over 1,000 units @	$0.0958								$56.58	$33.60	$27.92	$25.82	$25.18	$39.69	$208.79	
COG 1	$0.2612								$415.47						$415.47	
COG 2	$0.2612									$352.81					$352.81	
COG 3	$0.2052										$265.00				$265.00	
COG 4	$0.2052											$260.51			$260.51	
COG 5	$0.2052												$259.13		$259.13	
COG 6	$0.2052													$290.21	$290.21	
Summer Period 2015 Avg. COG	$0.2253 *															
LDAC	$0.0234								$37.22	$31.61	$30.22	$29.71	$29.55	$33.09	$191.40	
TOTAL		$2,150.60	$2,348.25	$2,762.11	$2,596.48	$2,399.26	$1,429.67	$13,686.38	$824.31	$733.04	$638.17	$631.07	$628.89	$678.02	$4,133.51	$17,819.88
Change		-$604.40	-$762.36	-$841.77	-$497.71	-$455.20	$200.02	-$2,961.41	$34.99	$29.72	$100.73	$99.03	$98.50	$110.31	$473.28	-$2,488.13
% Chg		-28.10%	-32.46%	-30.48%	-19.17%	-18.97%	13.99%	-21.64%	4.25%	4.05%	15.78%	15.69%	15.66%	16.27%	11.45%	-13.96%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2014 to October 2015

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2016 vs. Actual Summer 2015

Residential Heating	Summer 2015	Summer 2016
Customer Charge	$21.36	$21.36
First 50 Therms	$0.5449	$0.5449
Over 50 therms	$0.5449	$0.5449
LDAC	$0.0446	$0.0374
CGA	$0.2962	$0.3196

	Usage (Therms)	Summer 2015 Bill Amount	Summer 2016 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$25.79	$25.87	$0.08	0.3%	$0.00	0.0%	$0.12	0.5%	($0.04)	-0.2%
	10	$30.22	$30.38	$0.16	0.5%	$0.00	0.0%	$0.23	0.8%	($0.07)	-0.2%
	20	$39.07	$39.40	$0.32	0.8%	$0.00	0.0%	$0.47	1.2%	($0.14)	-0.4%
Average Monthly	25	$43.50	$43.91	$0.40	0.9%	$0.00	0.0%	$0.58	1.3%	($0.18)	-0.4%
	30	$47.93	$48.42	$0.48	1.0%	$0.00	0.0%	$0.70	1.5%	($0.22)	-0.5%
	45	$61.22	$61.95	$0.73	1.2%	$0.00	0.0%	$1.05	1.7%	($0.32)	-0.5%
	50	$65.65	$66.46	$0.81	1.2%	$0.00	0.0%	$1.17	1.8%	($0.36)	-0.5%
	75	$87.79	$89.00	$1.21	1.4%	$0.00	0.0%	$1.75	2.0%	($0.54)	-0.6%
	125	$132.08	$134.10	$2.02	1.5%	$0.00	0.0%	$2.92	2.2%	($0.90)	-0.7%
	150	$154.22	$156.65	$2.42	1.6%	$0.00	0.0%	$3.50	2.3%	($1.08)	-0.7%
	200	$198.51	$201.74	$3.23	1.6%	$0.00	0.0%	$4.67	2.4%	($1.44)	-0.7%

Schedule 9

Northern Utilities New Hampshire Division
Period Covered: May 1, 2016 - October 30, 2016
Variance Analysis

		2015 Summer (6 months actual)			Forecast Summer 2016 (6 months proposed)			Variance		
1	Therm Sales	7,340,720			9,940,234			2,599,514		
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		$ 739,996	$ 0.1008		$ 933,408	$ 0.0939		$ 193,412	$ (0.0069)
7										
8	Purchased Gas		1,816,350	0.2474		2,040,682	0.2053		$ 224,332	$ (0.0421)
9										
10	Storage & Peaking Gas		61,394	0.0084		49,933	0.0050		$ (11,461)	$ (0.0033)
11										
12	Hedging (Gain)/Loss		-	-		-	-		-	-
13										
14										
15	Total Volumes and Cost		$ 2,617,740	$ 0.3566	$ -	$ 3,024,024	$ 0.3042	$ -	$ 406,284	$ (0.0524)
16										
17	Prior Period Balance		($328,195)	$ (0.0447)		$ 23,260	$ 0.0023		$ 351,455	$ 0.0470
18						$ -	$ -		$ -	$ -
19	Interest		$ (13,658)	$ (0.0019)		(335)	$ (0.0000)		13,323	$ 0.0018
20	Refunds from Suppliers		-	$ -		-	$ -		-	$ -
21	Off-system Sales		(50,801)	$ (0.0069)						
22	Prior Period Adjustment									
23	Off-system Sales (Less Reversal)		(88,094)	$ (0.0120)		-	$ -		-	$ -
24	Capacity Release & Asset Management		-	$ -		$ -	$ -		-	$ -
25	Working Capital Allowance		431	$ 0.0001		2,251	$ 0.0002		1,820	$ 0.0002
26	Bad Debt Allowance		(12,773)	$ (0.0017)		$ 10,117	$ 0.0010		22,890	$ 0.0028
27	Fuel Inventory Financing		-	$ -		-	$ -		-	$ -
28	Local Production and Storage			$ -		-	$ -		-	$ -
29	Misc Overhead		95,875	$ 0.0131		117,870	$ 0.0119		21,995	$ (0.0012)
30										
31	Total Anticipated Indirect Cost of Gas		($397,215)	$ (0.0541)		153,163	$ 0.0154		550,378	$ 0.0695
32	Total Adjusted Cost		2,220,525	$ 0.3025		3,177,187	$ 0.3196		956,662	$ 0.0171

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

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

Base Capacity Costs

LN	BASE SENDOUT BY CLASS	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
2	**Total Therms**									
3	Res Heat	429,270	415,423	420,949	429,270	415,423	429,270	5,059,834	2,539,604	Schedule 10B, LN 52
4	Res General	14,301	13,840	14,024	14,301	13,840	14,301	168,571	84,608	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	78,354	75,826	76,835	78,354	75,826	78,354	923,558	463,547	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	151,728	146,833	148,787	151,728	146,833	151,728	1,788,425	897,636	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	153,145	148,205	150,176	153,145	148,205	153,145	1,781,088	906,020	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	191,582	185,402	187,868	191,582	185,402	191,582	2,258,186	1,133,417	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	212,981	206,111	208,853	212,981	206,111	212,981	2,254,535	1,260,019	Schedule 10B, LN 58
10	G42 High Annual-High Winter	39,075	37,814	38,317	39,075	37,814	39,075	460,577	231,170	Schedule 10B, LN 59
11	Total Firm Sales	1,270,435	1,229,453	1,245,810	1,270,435	1,229,453	1,270,435	14,694,774	7,516,021	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	33.79%	33.79%	33.79%	33.79%	33.79%	33.79%			LN 3 / LN 11
15	Res General	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	6.17%	6.17%	6.17%	6.17%	6.17%	6.17%			LN 5 / LN 11
17	G40 Low Annual-High Winter	11.94%	11.94%	11.94%	11.94%	11.94%	11.94%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%			LN 7 / LN 11
19	G41 Med Annual-High Winter	15.08%	15.08%	15.08%	15.08%	15.08%	15.08%			LN 8 / LN 11
20	G52 High Annual-Low Winter	16.76%	16.76%	16.76%	16.76%	16.76%	16.76%			LN 9 / LN 11
21	G42 High Annual-High Winter	3.08%	3.08%	3.08%	3.08%	3.08%	3.08%			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-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 71,214	$ 71,214	$ 71,214	$ 71,214	$ 71,214	$ 71,214	$ 890,605	$ 427,287	Schedule 1A, LN 69 - Schedule 1A, LN 80
26	Res Heat	$ 24,063	$ 24,063	$ 24,063	$ 24,063	$ 24,063	$ 24,063	$ 307,332	$ 144,377	LN 25 * LN 14
27	Res General	$ 802	$ 802	$ 802	$ 802	$ 802	$ 802	$ 10,239	$ 4,810	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 4,392	$ 4,392	$ 4,392	$ 4,392	$ 4,392	$ 4,392	$ 56,097	$ 26,353	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 8,505	$ 8,505	$ 8,505	$ 8,505	$ 8,505	$ 8,505	$ 108,628	$ 51,031	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 8,585	$ 8,585	$ 8,585	$ 8,585	$ 8,585	$ 8,585	$ 107,945	$ 51,507	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 10,739	$ 10,739	$ 10,739	$ 10,739	$ 10,739	$ 10,739	$ 137,161	$ 64,435	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 11,939	$ 11,939	$ 11,939	$ 11,939	$ 11,939	$ 11,939	$ 135,228	$ 71,632	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 27,975	$ 13,142	LN 25 * LN 21
34										
35	Residential	$ 24,864	$ 24,864	$ 24,864	$ 24,864	$ 24,864	$ 24,864	$ 317,571	$ 149,187	LN 26 + LN 27
36	SALES HLF CLASSES	$ 24,915	$ 24,915	$ 24,915	$ 24,915	$ 24,915	$ 24,915	$ 299,269	$ 149,492	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 21,435	$ 21,435	$ 21,435	$ 21,435	$ 21,435	$ 21,435	$ 273,765	$ 128,608	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

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

49

50 **REMAINING PIPELINE DEMAND**

Line		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
51		**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 30,079	$ 4,470	$ -	$ 715	$ 6,107	$ 57,227	$ 2,158,157	$ 98,599	Schedule 1A, LN 70
53										
54	Res Heat	$ 15,079	$ 2,241	$ -	$ 359	$ 3,062	$ 28,689	$ 1,081,915	$ 49,429	LN 40 Col D * LN 52
55	Res General	$ 233	$ 35	$ -	$ 6	$ 47	$ 443	$ 16,699	$ 763	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 457	$ 68	$ -	$ 11	$ 93	$ 870	$ 32,801	$ 1,499	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 6,420	$ 954	$ -	$ 153	$ 1,304	$ 12,215	$ 460,645	$ 21,045	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 857	$ 127	$ -	$ 20	$ 174	$ 1,630	$ 61,465	$ 2,808	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 5,435	$ 808	$ -	$ 129	$ 1,104	$ 10,341	$ 389,976	$ 17,817	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 99	$ 15	$ -	$ 2	$ 20	$ 187	$ 7,068	$ 323	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 1,499	$ 223	$ -	$ 36	$ 304	$ 2,853	$ 107,586	$ 4,915	LN 47 Col D * LN 52
62	TOTAL	$ 30,079	$ 4,470	$ -	$ 715	$ 6,107	$ 57,227	$ 2,158,157	$ 98,599	Sum LN 54 : LN 61
63										
64	Residential	$ 15,312	$ 2,275	$ -	$ 364	$ 3,109	$ 29,132	$ 1,098,614	$ 50,192	LN 54 + LN 55
65	SALES HLF CLASSES	$ 1,412	$ 210	$ -	$ 34	$ 287	$ 2,687	$ 101,335	$ 4,630	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 13,355	$ 1,985	$ -	$ 318	$ 2,711	$ 25,409	$ 958,208	$ 43,777	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

Line		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
69		**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 124,322	$ 18,474	$ -	$ 2,956	$ 25,241	$ 236,530	$ 10,845,021	$ 407,523	Schedule 1A, LN 73 - Schedule 1A, LN 79
71										
72	Res Heat	$ 62,324	$ 9,261	$ -	$ 1,482	$ 12,654	$ 118,576	$ 5,436,764	$ 204,297	LN 40 Col D * LN 70
73	Res General	$ 962	$ 143	$ -	$ 23	$ 195	$ 1,830	$ 83,916	$ 3,153	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 1,890	$ 281	$ -	$ 45	$ 384	$ 3,595	$ 164,831	$ 6,194	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 26,536	$ 3,943	$ -	$ 631	$ 5,388	$ 50,486	$ 2,314,803	$ 86,983	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 3,541	$ 526	$ -	$ 84	$ 719	$ 6,736	$ 308,871	$ 11,606	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 22,465	$ 3,338	$ -	$ 534	$ 4,561	$ 42,741	$ 1,959,683	$ 73,639	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 407	$ 61	$ -	$ 10	$ 83	$ 775	$ 35,519	$ 1,335	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 6,198	$ 921	$ -	$ 147	$ 1,258	$ 11,791	$ 540,634	$ 20,315	LN 47 Col D * LN 70
80	TOTAL	$ 124,322	$ 18,474	$ -	$ 2,956	$ 25,241	$ 236,530	$ 10,845,021	$ 407,523	Sum LN 72 : LN 79
81										
82	Residential	$ 63,286	$ 9,404	$ -	$ 1,505	$ 12,849	$ 120,406	$ 5,520,680	$ 207,450	LN 72 + LN 73
83	SALES HLF CLASSES	$ 5,837	$ 867	$ -	$ 139	$ 1,185	$ 11,106	$ 509,221	$ 19,135	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 55,198	$ 8,202	$ -	$ 1,312	$ 11,207	$ 105,018	$ 4,815,120	$ 180,937	LN 75 + LN 77 + LN 79

85

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

LN		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
87		**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,401,720)	$ -	Schedule 1A, LN 76
89										
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,705,331)	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,322)	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (51,702)	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (726,076)	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (96,883)	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (614,687)	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,141)	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (169,579)	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,401,720)	$ -	Sum LN 90 : LN 97
99										
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,731,652)	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (159,726)	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,510,342)	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

LN		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
105		**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**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**

		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
123		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	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**

		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
141		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
142	Res Heat	$ 77,404	$ 11,502	$ -	$ 1,840	$ 15,715	$ 147,265	$ 4,813,348	$ 253,726	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 1,195	$ 178	$ -	$ 28	$ 243	$ 2,273	$ 74,294	$ 3,916	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 2,347	$ 349	$ -	$ 56	$ 476	$ 4,465	$ 145,930	$ 7,692	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 32,956	$ 4,897	$ -	$ 784	$ 6,691	$ 62,701	$ 2,049,372	$ 108,028	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 4,397	$ 653	$ -	$ 105	$ 893	$ 8,366	$ 273,454	$ 14,415	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 27,900	$ 4,146	$ -	$ 663	$ 5,665	$ 53,082	$ 1,734,973	$ 91,456	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 506	$ 75	$ -	$ 12	$ 103	$ 962	$ 31,446	$ 1,658	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 7,697	$ 1,144	$ -	$ 183	$ 1,563	$ 14,644	$ 478,641	$ 25,231	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 154,401	$ 22,944	$ -	$ 3,671	$ 31,348	$ 293,757	$ 9,601,458	$ 506,121	Sum LN 142 : LN 149
151										
152	Residential	$ 78,598	$ 11,679	$ -	$ 1,869	$ 15,958	$ 149,538	$ 4,887,642	$ 257,642	LN 142 + LN 143
153	SALES HLF CLASSES	$ 7,250	$ 1,077	$ -	$ 172	$ 1,472	$ 13,793	$ 450,831	$ 23,765	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 68,553	$ 10,187	$ -	$ 1,630	$ 13,918	$ 130,426	$ 4,262,986	$ 224,715	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
157		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	SUMMER	
158	Res Heat	$ 101,466	$ 35,565	$ 24,063	$ 25,903	$ 39,778	$ 171,327	$ 5,120,680	$ 398,103	LN 142 + LN 26
159	Res General	$ 1,996	$ 979	$ 802	$ 830	$ 1,044	$ 3,075	$ 84,533	$ 8,726	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 6,739	$ 4,741	$ 4,392	$ 4,448	$ 4,869	$ 8,857	$ 202,027	$ 34,045	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 41,461	$ 13,402	$ 8,505	$ 9,289	$ 15,196	$ 71,206	$ 2,158,000	$ 159,059	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 12,982	$ 9,238	$ 8,585	$ 8,689	$ 9,477	$ 16,951	$ 381,399	$ 65,922	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 38,639	$ 14,885	$ 10,739	$ 11,402	$ 16,404	$ 63,821	$ 1,872,134	$ 155,890	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 12,444	$ 12,014	$ 11,939	$ 11,951	$ 12,041	$ 12,901	$ 166,674	$ 73,290	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 9,887	$ 3,334	$ 2,190	$ 2,373	$ 3,753	$ 16,834	$ 506,616	$ 38,373	LN 149 + LN 33
166	TOTAL	$ 225,616	$ 94,158	$ 71,214	$ 74,885	$ 102,563	$ 364,972	$ 10,492,063	$ 933,408	Sum LN 158 : LN 165
167										
168	Residential	$ 103,463	$ 36,544	$ 24,864	$ 26,733	$ 40,822	$ 174,402	$ 5,205,213	$ 406,829	LN 158 + LN 159
169	SALES HLF CLASSES	$ 32,165	$ 25,993	$ 24,915	$ 25,088	$ 26,387	$ 38,709	$ 750,100	$ 173,257	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 89,988	$ 31,621	$ 21,435	$ 23,064	$ 35,353	$ 151,861	$ 4,536,750	$ 353,322	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								33%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								67%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2015 - 2016 Period

Line No.															
	Forecasted Normal Sales By Class- Therms														
	Calendar Month Firm Sales Volumes														
	Normal Winter	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
1	Res Heat	1,894,881	2,791,565	3,524,244	2,946,169	2,271,130	1,338,393	688,654	458,665	416,590	433,060	474,097	887,660	18,125,108	3,358,727
2	Res General	27,066	39,873	50,339	42,082	32,440	19,117	22,943	15,281	13,879	14,428	15,795	29,573	322,814	111,897
3	**Total Residential**	**1,921,947**	**2,831,438**	**3,574,582**	**2,988,250**	**2,303,570**	**1,357,510**	**711,597**	**473,945**	**430,469**	**447,488**	**489,892**	**917,233**	**18,447,921**	**3,470,624**
4	G50 Low Annual-Low Winter	110,064	162,148	204,705	171,128	131,918	77,740	125,698	83,719	76,039	79,045	86,536	162,022	1,470,764	613,060
5	G40 Low Annual-High Winter	945,721	1,393,250	1,758,925	1,470,411	1,133,505	667,982	243,408	162,117	147,246	153,067	167,572	313,748	8,556,954	1,187,159
6	G51 Med Annual-Low Winter	174,012	256,356	323,640	270,554	208,564	122,908	245,682	163,631	148,621	154,497	169,137	316,678	2,554,281	1,198,247
7	G41 Med Annual-High Winter	824,236	1,214,275	1,532,976	1,281,525	987,897	582,175	307,344	204,700	185,923	193,273	211,588	396,160	7,922,072	1,498,988
8	G52 High Annual-Low Winter	131,666	193,973	244,883	204,715	157,810	92,999	341,674	227,565	206,690	214,862	235,222	440,411	2,692,471	1,666,425
9	G42 High Annual-High Winter	164,789	242,770	306,488	256,215	197,510	116,394	62,685	41,750	37,921	39,420	43,155	80,800	1,589,897	305,732
10	**Total C&I**	**2,350,488**	**3,462,772**	**4,371,617**	**3,654,549**	**2,817,203**	**1,660,198**	**1,326,492**	**883,484**	**802,440**	**834,164**	**913,211**	**1,709,819**	**24,786,438**	**6,469,610**
11	**Total Sales**	**4,272,435**	**6,294,210**	**7,946,200**	**6,642,799**	**5,120,773**	**3,017,709**	**2,038,088**	**1,357,429**	**1,232,909**	**1,281,652**	**1,403,103**	**2,627,052**	**43,234,360**	**9,940,234**
12															
13	Residential Heat & Non Heat	1,921,947	2,831,438	3,574,582	2,988,250	2,303,570	1,357,510	711,597	473,945	430,469	447,488	489,892	917,233	18,447,921	3,470,624
14	SALES HLF CLASSES	415,742	612,477	773,229	646,397	498,292	293,647	713,054	474,916	431,351	448,404	490,895	919,111	6,717,516	3,477,731
15	SALES LLF CLASSES	1,934,746	2,850,295	3,598,389	3,008,152	2,318,911	1,366,551	613,438	408,568	371,089	385,760	422,315	790,708	18,068,923	2,991,879
16	**Total Firm Sales**	**4,272,435**	**6,294,210**	**7,946,200**	**6,642,799**	**5,120,773**	**3,017,709**	**2,038,088**	**1,357,429**	**1,232,909**	**1,281,652**	**1,403,103**	**2,627,052**	**43,234,360**	**9,940,234**
17															
18	**ESTIMATED SENDOUT BY CLASS - Therms**														
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)							Unaccounted For)							
20	Normal Winter	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**
21	Res Heat	1,914,114	2,819,754	3,559,765	2,975,906	2,294,156	1,352,081	695,740	463,456	420,949	437,591	479,043	896,749	18,309,304	3,393,528
22	Res General	27,340	40,276	50,846	42,506	32,769	19,312	23,179	15,440	14,024	14,579	15,960	29,876	326,107	113,057
23	G50 Low Annual-Low Winter	111,181	163,785	206,769	172,855	133,256	78,536	126,992	84,593	76,835	79,872	87,439	163,681	1,485,794	619,412
24	G40 Low Annual-High Winter	955,320	1,407,319	1,776,653	1,485,253	1,144,997	674,814	245,913	163,811	148,787	154,669	169,320	316,961	8,643,816	1,199,460
25	G51 Med Annual-Low Winter	175,778	258,945	326,902	273,285	210,678	124,165	248,210	165,341	150,176	156,113	170,902	319,921	2,580,416	1,210,662
26	G41 Med Annual-High Winter	832,602	1,226,537	1,548,427	1,294,461	997,912	588,128	310,506	206,839	187,868	195,295	213,795	400,216	8,002,588	1,514,520
27	G52 High Annual-Low Winter	133,003	195,931	247,351	206,782	159,410	93,950	345,190	229,943	208,853	217,110	237,676	444,920	2,720,118	1,683,692
28	G42 High Annual-High Winter	166,462	245,221	309,577	258,801	199,512	117,584	63,330	42,187	38,317	39,832	43,605	81,627	1,606,057	308,899
29	**Subtotal**														
30	Residential	1,941,454	2,860,030	3,610,611	3,018,413	2,326,924	1,371,393	718,919	478,896	434,973	452,169	495,003	926,624	18,635,411	3,506,585
31	SALES HLF CLASSES	419,962	618,662	781,022	652,922	503,344	296,650	720,391	479,877	435,864	453,095	496,016	928,522	6,786,328	3,513,766
32	SALES LLF CLASSES	1,954,384	2,879,078	3,634,657	3,038,515	2,342,421	1,380,527	619,750	412,836	374,972	389,796	426,721	798,804	18,252,461	3,022,879
33	**Total Firm Sales**	4,315,800	6,357,770	8,026,290	6,709,850	5,172,690	3,048,570	2,059,060	1,371,610	1,245,810	1,295,060	1,417,740	2,653,950	43,674,200	10,043,230

Northern Utilities - NEW HAMPSHIRE DIVISION
2015 - 2016 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	13,847
37	Res General	461
38	G50 Low Annual-Low Winter	2,528
39	G40 Low Annual-High Winter	4,894
40	G51 Med Annual-Low Winter	4,940
41	G41 Med Annual-High Winter	6,180
42	G52 High Annual-Low Winter	6,870
43	G42 High Annual-High Winter	1,260
44	**Subtotal**	
45	Residential	14,309
46	SALES HLF CLASSES	14,338
47	SALES LLF CLASSES	12,335
48	**Total Firm Sales**	**40,982**

49	**BASE SENDOUT BY CLASS - Therms**														
50	Days per Month	30	31	31	29	31	30	31	30	31	31	30	31		
51		**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**
52	Res Heat	415,423	429,270	429,270	401,575	429,270	415,423	429,270	415,423	420,949	429,270	415,423	429,270	5,059,834	2,539,604
53	Res General	13,840	14,301	14,301	13,379	14,301	13,840	14,301	13,840	14,024	14,301	13,840	14,301	168,571	84,608
54	G50 Low Annual-Low Winter	75,826	78,354	78,354	73,298	78,354	75,826	78,354	75,826	76,835	78,354	75,826	78,354	923,558	463,547
55	G40 Low Annual-High Winter	146,833	151,728	151,728	141,939	151,728	146,833	151,728	146,833	148,787	151,728	146,833	151,728	1,788,425	897,636
56	G51 Med Annual-Low Winter	148,205	153,145	153,145	143,264	153,145	124,165	153,145	148,205	150,176	153,145	148,205	153,145	1,781,088	906,020
57	G41 Med Annual-High Winter	185,402	191,582	191,582	179,222	191,582	185,402	191,582	185,402	187,868	191,582	185,402	191,582	2,258,186	1,133,417
58	G52 High Annual-Low Winter	133,003	195,931	212,981	199,241	159,410	93,950	212,981	206,111	208,853	212,981	206,111	212,981	2,254,535	1,260,019
59	G42 High Annual-High Winter	37,814	39,075	39,075	36,554	39,075	37,814	39,075	37,814	38,317	39,075	37,814	39,075	460,577	231,170
60	**Subtotal**														
61	Residential	429,263	443,571	443,571	414,954	443,571	429,263	443,571	429,263	434,973	443,571	429,263	443,571	5,228,405	2,624,212
62	SALES HLF CLASSES	357,033	427,430	444,480	415,804	390,908	293,941	444,480	430,142	435,864	444,480	430,142	444,480	4,959,181	2,629,586
63	SALES LLF CLASSES	370,049	382,384	382,384	357,714	382,384	370,049	382,384	370,049	374,972	382,384	370,049	382,384	4,507,188	2,262,223
64	**Total Firm Sales**	1,156,345	1,253,385	1,270,435	1,188,471	1,216,864	1,093,252	1,270,435	1,229,453	1,245,810	1,270,435	1,229,453	1,270,435	14,694,774	7,516,021
65															

66	**REMAINING SENDOUT BY CLASS - Therms**														
67		**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**SUMMER**
68	Res Heat	1,498,691	2,390,484	3,130,495	2,574,331	1,864,886	936,658	266,470	48,034	-	8,321	63,621	467,479	13,249,470	853,924
69	Res General	13,500	25,975	36,545	29,128	18,467	5,473	8,878	1,600	-	277	2,120	15,574	157,536	28,449
70	G50 Low Annual-Low Winter	35,355	85,432	128,415	99,557	54,902	2,710	48,638	8,767	-	1,519	11,613	85,328	562,235	155,865
71	G40 Low Annual-High Winter	808,487	1,255,591	1,624,925	1,343,315	993,269	527,980	94,185	16,978	-	2,941	22,487	165,233	6,855,392	301,824
72	G51 Med Annual-Low Winter	27,573	105,800	173,758	130,021	57,533	-	95,065	17,136	-	2,968	22,697	166,776	799,328	304,643
73	G41 Med Annual-High Winter	647,200	1,034,956	1,356,846	1,115,239	806,331	402,727	118,925	21,437	-	3,713	28,394	208,634	5,744,401	381,103
74	G52 High Annual-Low Winter	-	-	34,370	7,541	-	-	132,209	23,832	-	4,128	31,565	231,939	465,583	423,672
75	G42 High Annual-High Winter	128,648	206,147	270,502	222,247	160,438	79,770	24,256	4,372	-	757	5,791	42,553	1,145,481	77,729
76	**Subtotal**														
77	Residential	1,512,192	2,416,459	3,167,040	2,603,459	1,883,353	942,131	275,348	49,634	-	8,598	65,740	483,053	13,407,006	882,373
78	SALES HLF CLASSES	62,929	191,232	336,542	237,118	112,436	2,710	275,912	49,736	-	8,615	65,875	484,042	1,827,147	884,180
79	SALES LLF CLASSES	1,584,335	2,496,694	3,252,273	2,680,801	1,960,037	1,010,477	237,366	42,787	-	7,412	56,672	416,420	13,745,273	760,656
80	**Total Firm Sales**	3,159,455	5,104,385	6,755,855	5,521,379	3,955,826	1,955,318	788,625	142,157	-	24,625	188,287	1,383,515	28,979,426	2,527,209

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining S   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)										
	2015-2016	2015-2016 Compared to 2014-2015					2015-2016 Compared to 2014-2015				
	Forecast	2014-2015 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2013-2014 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	567,582	463,370	104,212	22.5%	10,962	93,250	529,156	38,426	7.3%	26,464	11,962
Jun	447,712	406,358	41,354	10.2%	10,527	30,827	414,423	33,289	8.0%	20,813	12,476
Jul	353,738	377,555	-23,817	-6.3%	9,619	-33,437	333,540	20,198	6.1%	16,832	3,366
Aug	361,107	328,341	32,766	10.0%	8,390	24,376	327,519	33,588	10.3%	16,488	17,100
Sep	363,906	363,264	643	0.2%	10,840	-10,198	339,140	24,766	7.3%	16,864	7,902
Oct	430,326	464,142	-33,815	-7.3%	13,410	-47,226	415,928	14,398	3.5%	20,402	-6,004
Summer	2,524,372	2,403,029	121,342	5.0%	63,748	57,594	2,359,706	164,666	7.0%	117,864	46,802

Note 1 Company Forecast
Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data
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
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	31,810	31,075	735	2.4%	30,295	1,515	5.0%
Jun	31,725	30,924	801	2.6%	30,208	1,517	5.0%
Jul	31,600	30,815	785	2.5%	30,082	1,518	5.0%
Aug	31,632	30,844	788	2.6%	30,116	1,516	5.0%
Sep	31,857	30,934	923	3.0%	30,348	1,509	5.0%
Oct	32,232	31,327	905	2.9%	30,725	1,507	4.9%
Summer	31,809	30,987	823	2.7%	30,296	1,514	5.0%

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

	Total Division Use Per Meter						
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	17.84	14.91	2.93	19.7%	17.47	0.38	2.2%
Jun	14.11	13.14	0.97	7.4%	13.72	0.39	2.9%
Jul	11.19	12.25	-1.06	-8.6%	11.09	0.11	1.0%
Aug	11.42	10.65	0.77	7.2%	10.88	0.54	5.0%
Sep	11.42	11.74	-0.32	-2.7%	11.18	0.25	2.2%
Oct	13.35	14.82	-1.47	-9.9%	13.54	-0.19	-1.4%
Summer	79.36	77.55	1.81	2.3%	77.89	1.48	1.9%

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

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

	Residential Non-Heat Metered Deliveries (Dth)										
	2015-2016	2015-2016 Compared to 2014-2015					2015-2016 Compared to 2014-2015				
	Forecast	2014-2015 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2013-2014 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	2,424	2,022	402	19.9%	93	310	2,484	-60	-2.4%	-43	-17
Jun	1,984	1,853	131	7.1%	71	60	2,019	-35	-1.8%	-35	-1
Jul	1,733	1,701	32	1.9%	55	-23	1,843	-110	-6.0%	-32	-78
Aug	1,739	1,544	195	12.6%	83	112	1,680	59	3.5%	-30	89
Sep	1,601	1,400	202	14.4%	98	104	1,619	-18	-1.1%	-28	10
Oct	1,708	1,501	207	13.8%	94	113	1,826	-118	-6.4%	-33	-85
Summer	11,190	10,020	1,170	11.7%	494	675	11,471	-281	-2.5%	-200	-82

Note 1 Company Forecast
Note 2 Actual Data
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual Data
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	1,597	1,527	70	4.6%	1,625	-28	-1.7%
Jun	1,600	1,541	59	3.8%	1,628	-28	-1.7%
Jul	1,590	1,540	50	3.3%	1,618	-28	-1.7%
Aug	1,526	1,448	78	5.4%	1,554	-28	-1.8%
Sep	1,520	1,421	99	7.0%	1,547	-27	-1.7%
Oct	1,477	1,390	87	6.3%	1,504	-27	-1.8%
Summer	1,552	1,478	74	5.0%	1,579	-28	-1.7%

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

	Total Division Use Per Meter						
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	1.52	1.32	0.19	14.6%	1.53	-0.01	-0.7%
Jun	1.24	1.20	0.04	3.1%	1.24	0.00	0.0%
Jul	1.09	1.10	-0.01	-1.3%	1.14	-0.05	-4.3%
Aug	1.14	1.07	0.07	6.9%	1.08	0.06	5.4%
Sep	1.05	0.98	0.07	6.9%	1.05	0.01	0.6%
Oct	1.16	1.08	0.08	7.1%	1.21	-0.06	-4.7%
Summer	7.21	6.78	0.43	6.4%	7.26	-0.05	-0.7%

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

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

	Residential Heat Metered Deliveries (Dth)										
	2015-2016	2015-2016 Compared to 2014-2015					2015-2016 Compared to 2014-2015				
	Forecast	2014-2015 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2013-2014 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	112,946	82,345	30,601	37.2%	1,673	28,928	107,292	5,655	5.3%	6,480	-826
Jun	57,551	50,959	6,592	12.9%	1,241	5,350	54,241	3,310	6.1%	3,279	31
Jul	36,473	35,845	628	1.8%	974	-346	35,924	549	1.5%	2,174	-1,625
Aug	34,988	31,900	3,089	9.7%	777	2,311	31,297	3,692	11.8%	1,885	1,806
Sep	36,493	33,145	3,348	10.1%	980	2,369	34,211	2,283	6.7%	2,042	240
Oct	57,421	58,274	-853	-1.5%	1,823	-2,676	56,904	517	0.9%	3,355	-2,838
Summer	335,873	292,468	43,404	14.8%	7,469	35,935	319,868	16,005	5.0%	19,216	-3,211

Note 1 Company Forecast
Note 2 Actual Data
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual Data
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	23,378	22,912	466	2.0%	22,046	1,332	6.0%
Jun	23,358	22,802	556	2.4%	22,026	1,332	6.0%
Jul	23,334	22,716	618	2.7%	22,002	1,332	6.1%
Aug	23,435	22,877	558	2.4%	22,103	1,332	6.0%
Sep	23,635	22,956	679	3.0%	22,303	1,332	6.0%
Oct	23,915	23,189	726	3.1%	22,583	1,332	5.9%
Summer	23,509	22,909	600	2.6%	22,177	1,332	6.0%

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

	Total Division Use Per Meter						
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	4.83	3.59	1.24	34.4%	4.87	-0.04	-0.7%
Jun	2.46	2.23	0.23	10.2%	2.46	0.00	0.1%
Jul	1.56	1.58	-0.01	-0.9%	1.63	-0.07	-4.3%
Aug	1.49	1.39	0.10	7.1%	1.42	0.08	5.4%
Sep	1.54	1.44	0.10	6.9%	1.53	0.01	0.7%
Oct	2.40	2.51	-0.11	-4.5%	2.52	-0.12	-4.7%
Summer	14.29	12.77	1.52	11.9%	14.42	-0.14	-0.9%

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

Total Division C&I Metered Deliveries (Dth)											
	2015-2016	2015-2016 Compared to 2014-2015					2015-2016 Compared to 2014-2015				
	Forecast	2014-2015 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2013-2014 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	452,212	379,003	73,209	19.3%	11,393	61,815	419,381	32,831	7.8%	13,390	19,442
Jun	388,177	353,546	34,632	9.8%	10,018	24,613	358,163	30,014	8.4%	11,667	18,348
Jul	315,532	340,009	-24,478	-7.2%	6,090	-30,568	295,773	19,759	6.7%	9,817	9,942
Aug	324,379	294,897	29,482	10.0%	6,898	22,585	294,542	29,838	10.1%	9,690	20,148
Sep	325,811	328,719	-2,907	-0.9%	7,294	-10,201	303,310	22,501	7.4%	9,545	12,957
Oct	371,197	404,367	-33,170	-8.2%	5,542	-38,712	357,199	13,998	3.9%	10,896	3,102
Summer	2,177,309	2,100,541	76,768	3.7%	47,236	29,533	2,028,367	148,942	7.3%	65,004	83,938

Note 1 Company Forecast
Note 2 Actual Data
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual Data
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

Total Division Meter Counts							
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	6,835	6,636	199	3.0%	6,624	211	3.2%
Jun	6,767	6,581	186	2.8%	6,554	213	3.3%
Jul	6,676	6,559	117	1.8%	6,462	214	3.3%
Aug	6,671	6,519	152	2.3%	6,459	212	3.3%
Sep	6,702	6,557	145	2.2%	6,498	204	3.1%
Oct	6,840	6,748	92	1.4%	6,638	202	3.1%
Summer	6,749	6,600	149	2.3%	6,539	210	3.2%

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

Total Division Use Per Meter							
	2015-2016	Compared to 2014-2015			Compared to 2014-2015		
	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	66.16	57.11	9.04	15.8%	63.31	2.84	4.5%
Jun	57.36	53.72	3.64	6.8%	54.65	2.71	5.0%
Jul	47.26	51.84	-4.58	-8.8%	45.77	1.49	3.3%
Aug	48.62	45.24	3.39	7.5%	45.60	3.02	6.6%
Sep	48.61	50.13	-1.52	-3.0%	46.68	1.93	4.1%
Oct	54.26	59.92	-5.66	-9.4%	53.81	0.45	0.8%
Summer	322.61	318.26	4.35	1.4%	310.19	12.45	4.0%

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

Northern Utilities, Inc.
New Hampshire Division
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-16	2,294	68,865	24,341	12,570	30,734	24,568	6,269	34,167	0	203,809
Jun-16	1,528	45,866	16,212	8,372	20,470	16,363	4,175	22,757	0	135,743
Jul-16	1,388	41,659	14,725	7,604	18,592	14,862	3,792	20,669	0	123,291
Aug-16	1,443	43,306	15,307	7,905	19,327	15,450	3,942	21,486	0	128,165
Sep-16	1,579	47,410	16,757	8,654	21,159	16,914	4,316	23,522	0	140,310
Oct-16	2,957	88,766	31,375	16,202	39,616	31,668	8,080	44,041	0	262,705
Peak	21,092	1,476,638	736,979	85,770	642,308	135,603	128,417	102,605	0	3,329,413
Off-Peak	11,190	335,873	118,716	61,306	149,899	119,825	30,573	166,642	0	994,023
Total	32,281	1,812,511	855,695	147,076	792,207	255,428	158,990	269,247	0	4,323,436

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-16	2,294	68,865	28,630	14,960	46,560	42,212	29,153	141,943	93,939	468,559
Jun-16	1,528	45,866	20,237	10,615	35,321	32,920	25,650	123,894	88,153	384,186
Jul-16	1,388	41,659	18,467	9,689	32,399	30,254	23,756	114,690	81,951	354,253
Aug-16	1,443	43,306	19,187	10,067	33,644	31,410	24,643	118,980	84,977	367,657
Sep-16	1,579	47,410	20,768	10,889	35,958	33,413	25,715	124,306	87,845	387,884
Oct-16	2,957	88,766	36,221	18,903	57,497	51,603	33,936	165,812	106,137	561,833
Peak	21,092	1,476,638	854,954	103,850	1,078,407	290,874	492,390	936,018	526,385	5,780,607
Off-Peak	11,190	335,873	143,510	75,124	241,379	221,813	162,855	789,626	543,002	2,524,372
Total	32,281	1,812,511	998,464	178,974	1,319,786	512,687	655,245	1,725,643	1,069,387	8,304,979

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-16	100%	100%	85%	84%	66%	58%	22%	24%	0%	43%
Jun-16	100%	100%	80%	79%	58%	50%	16%	18%	0%	35%
Jul-16	100%	100%	80%	78%	57%	49%	16%	18%	0%	35%
Aug-16	100%	100%	80%	79%	57%	49%	16%	18%	0%	35%
Sep-16	100%	100%	81%	79%	59%	51%	17%	19%	0%	36%
Oct-16	100%	100%	87%	86%	69%	61%	24%	27%	0%	47%
Peak	100%	100%	86%	83%	60%	47%	26%	11%	0%	58%
Off-Peak	100%	100%	83%	82%	62%	54%	19%	21%	0%	39%
Total	100%	100%	86%	82%	60%	50%	24%	16%	0%	52%

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-16	2,424	112,946	48,892	11,236	59,753	27,113	11,046	53,140	0	326,551
Jun-16	1,984	57,551	19,149	10,117	25,116	19,341	5,294	45,838	0	184,391
Jul-16	1,733	36,473	10,802	10,063	13,322	17,506	1,807	14,583	0	106,289
Aug-16	1,739	34,988	10,576	10,820	14,113	20,342	3,821	19,227	0	115,626
Sep-16	1,601	36,493	11,254	10,037	15,257	18,012	3,377	16,886	0	112,918
Oct-16	1,708	57,421	18,042	9,032	22,339	17,510	5,228	16,969	0	148,249
Peak	21,092	1,476,638	736,979	85,770	642,308	135,603	128,417	102,605	0	3,329,413
Off-Peak	11,190	335,873	118,716	61,306	149,899	119,825	30,573	166,642	0	994,023
Total	32,281	1,812,511	855,695	147,076	792,207	255,428	158,990	269,247	0	4,323,436

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-16	2,424	112,946	56,216	13,425	83,960	43,748	32,696	134,662	87,506	567,582
Jun-16	1,984	57,551	23,637	12,530	40,598	37,274	24,108	158,607	91,424	447,712
Jul-16	1,733	36,473	13,692	12,351	23,900	34,107	21,121	118,205	92,157	353,738
Aug-16	1,739	34,988	12,956	13,033	23,479	36,525	23,544	127,166	87,676	361,107
Sep-16	1,601	36,493	13,972	12,373	26,527	34,056	27,195	122,333	89,355	363,906
Oct-16	1,708	57,421	23,037	11,412	42,916	36,103	34,191	128,654	94,885	430,326
Peak	21,092	1,476,638	854,954	103,850	1,078,407	290,874	492,390	936,018	526,385	5,780,607
Off-Peak	11,190	335,873	143,510	75,124	241,379	221,813	162,855	789,626	543,002	2,524,372
Total	32,281	1,812,511	998,464	178,974	1,319,786	512,687	655,245	1,725,643	1,069,387	8,304,979

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-16	100%	100%	87%	84%	71%	62%	34%	39%	0%	58%
Jun-16	100%	100%	81%	81%	62%	52%	22%	29%	0%	41%
Jul-16	100%	100%	79%	81%	56%	51%	9%	12%	0%	30%
Aug-16	100%	100%	82%	83%	60%	56%	16%	15%	0%	32%
Sep-16	100%	100%	81%	81%	58%	53%	12%	14%	0%	31%
Oct-16	100%	100%	78%	79%	52%	49%	15%	13%	0%	34%
Peak	100%	100%	86%	83%	60%	47%	26%	11%	0%	58%
Off-Peak	100%	100%	83%	82%	62%	54%	19%	21%	0%	39%
Total	100%	100%	86%	82%	60%	50%	24%	16%	0%	52%

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-15	788,533	0.03%	237	332,105	95,138	427,244	427,480	0.95%	4,100	431,580	17,490	449,070
Dec-15	1,052,790	0.03%	316	532,370	97,051	629,421	629,737	0.95%	6,040	635,777	99,493	735,270
Jan-16	1,279,452	0.03%	384	715,605	79,015	794,620	795,004	0.95%	7,625	802,629	152,721	955,350
Feb-16	1,101,629	0.03%	330	751,045	-86,765	664,280	664,610	0.95%	6,375	670,985	117,486	788,471
Mar-16	925,268	0.03%	278	589,726	-77,648	512,077	512,355	0.95%	4,914	517,269	47,344	564,613
Apr-16	632,936	0.03%	190	408,561	-106,791	301,771	301,961	0.95%	2,896	304,857	0	304,857
May-16	468,559	0.03%	141	326,551	-122,742	203,809	203,949	0.95%	1,957	205,906	0	205,906
Jun-16	384,186	0.03%	115	184,391	-48,648	135,743	135,858	0.95%	1,303	137,161	0	137,161
Jul-16	354,253	0.03%	106	106,289	17,002	123,291	123,397	0.95%	1,184	124,581	0	124,581
Aug-16	367,657	0.03%	110	115,626	12,539	128,165	128,275	0.95%	1,231	129,506	0	129,506
Sep-16	387,884	0.03%	116	112,918	27,392	140,310	140,427	0.95%	1,347	141,774	0	141,774
Oct-16	561,833	0.03%	169	148,249	114,456	262,705	262,874	0.95%	2,521	265,395	0	265,395
Peak	5,780,607	0.03%	1,734	3,329,413	0	3,329,413	3,331,147	0.95%	31,950	3,363,097	434,534	3,797,631
Off-Peak	2,524,372	0.03%	757	994,023	0	994,023	994,781	0.95%	9,542	1,004,323	0	1,004,323
Annual	8,304,979	0.03%	2,491	4,323,436	0	4,323,436	4,325,927	0.95%	41,493	4,367,420	434,534	4,801,954

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
2	**Total Therms**								
3	Res Heat	429,270	415,423	420,949	429,270	415,423	429,270	5,059,834	2,539,604
4	Res General	14,301	13,840	14,024	14,301	13,840	14,301	168,571	84,608
5	G50 Low Annual-Low Winter	78,354	75,826	76,835	78,354	75,826	78,354	923,558	463,547
6	G40 Low Annual-High Winter	151,728	146,833	148,787	151,728	146,833	151,728	1,788,425	897,636
7	G51 Med Annual-Low Winter	153,145	148,205	150,176	153,145	148,205	153,145	1,781,088	906,020
8	G41 Med Annual-High Winter	191,582	185,402	187,868	191,582	185,402	191,582	2,258,186	1,133,417
9	G52 High Annual-Low Winter	212,981	206,111	208,853	212,981	206,111	212,981	2,254,535	1,260,019
10	G42 High Annual-High Winter	39,075	37,814	38,317	39,075	37,814	39,075	460,577	231,170
11	Total Firm Sales	1,270,435	1,229,453	1,245,810	1,270,435	1,229,453	1,270,435	14,694,774	7,516,021
12	**% of Total**								
13	Res Heat	33.79%	33.79%	33.79%	33.79%	33.79%	33.79%		
14	Res General	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%		
15	G50 Low Annual-Low Winter	6.17%	6.17%	6.17%	6.17%	6.17%	6.17%		
16	G40 Low Annual-High Winter	11.94%	11.94%	11.94%	11.94%	11.94%	11.94%		
17	G51 Med Annual-Low Winter	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%		
18	G41 Med Annual-High Winter	15.08%	15.08%	15.08%	15.08%	15.08%	15.08%		
19	G52 High Annual-Low Winter	16.76%	16.76%	16.76%	16.76%	16.76%	16.76%		
20	G42 High Annual-High Winter	3.08%	3.08%	3.08%	3.08%	3.08%	3.08%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
23	TOTAL BASE COMMODITY Excld Hedging	$ 237,246	$ 227,599	$ 236,310	$ 247,835	$ 250,202	$ 304,162	$ 5,419,817	$ 1,503,355
24	Res Heat	$ 80,164	$ 76,904	$ 79,847	$ 83,741	$ 84,541	$ 102,774	$ 1,871,241	$ 507,972
25	Res General	$ 2,671	$ 2,562	$ 2,660	$ 2,790	$ 2,817	$ 3,424	$ 62,341	$ 16,923
26	G50 Low Annual-Low Winter	$ 14,632	$ 14,037	$ 14,574	$ 15,285	$ 15,431	$ 18,759	$ 341,553	$ 92,719
27	G40 Low Annual-High Winter	$ 28,334	$ 27,182	$ 28,222	$ 29,599	$ 29,882	$ 36,326	$ 661,400	$ 179,545
28	G51 Med Annual-Low Winter	$ 28,599	$ 27,436	$ 28,486	$ 29,875	$ 30,161	$ 36,665	$ 660,659	$ 181,222
29	G41 Med Annual-High Winter	$ 35,777	$ 34,322	$ 35,636	$ 37,374	$ 37,731	$ 45,868	$ 835,128	$ 226,706
30	G52 High Annual-Low Winter	$ 39,773	$ 38,156	$ 39,616	$ 41,548	$ 41,945	$ 50,991	$ 817,163	$ 252,029
31	G42 High Annual-High Winter	$ 7,297	$ 7,000	$ 7,268	$ 7,623	$ 7,695	$ 9,355	$ 170,332	$ 46,239
32									
33	Residential	$ 82,834	$ 79,466	$ 82,507	$ 86,531	$ 87,358	$ 106,198	$ 1,933,582	$ 524,895
34	SALES HLF CLASSES	$ 83,004	$ 79,629	$ 82,676	$ 86,709	$ 87,537	$ 106,415	$ 1,819,375	$ 525,970
35	SALES LLF CLASSES	$ 71,408	$ 68,504	$ 71,126	$ 74,595	$ 75,308	$ 91,549	$ 1,666,860	$ 452,490

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
37	TOTAL BASE HEDGING COMMODITY	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,704	$ -
38	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,818	$ -
39	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ 260	$ -
40	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,427	$ -
41	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,763	$ -
42	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,789	$ -
43	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,489	$ -
44	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,444	$ -
45	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 712	$ -
46									
47	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,079	$ -
48	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,661	$ -
49	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,964	$ -

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

		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	Summer
50	**REMAINING SENDOUT BY CLASS**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
51	**Total Therms**								
52	Res Heat	266,470	48,034	-	8,321	63,621	467,479	13,249,470	853,924
53	Res General	8,878	1,600	-	277	2,120	15,574	157,536	28,449
54	G50 Low Annual-Low Winter	48,638	8,767	-	1,519	11,613	85,328	562,235	155,865
55	G40 Low Annual-High Winter	94,185	16,978	-	2,941	22,487	165,233	6,855,392	301,824
56	G51 Med Annual-Low Winter	95,065	17,136	-	2,968	22,697	166,776	799,328	304,643
57	G41 Med Annual-High Winter	118,925	21,437	-	3,713	28,394	208,634	5,744,401	381,103
58	G52 High Annual-Low Winter	132,209	23,832	-	4,128	31,565	231,939	465,583	423,672
59	G42 High Annual-High Winter	24,256	4,372	-	757	5,791	42,553	1,145,481	77,729
60	Total Firm Sales	788,625	142,157	-	24,625	188,287	1,383,515	28,979,426	2,527,209
61	**% of Total**								
62	Res Heat	33.79%	33.79%	33.79%	33.79%	33.79%	33.79%		
63	Res General	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%		
64	G50 Low Annual-Low Winter	6.17%	6.17%	6.17%	6.17%	6.17%	6.17%		
65	G40 Low Annual-High Winter	11.94%	11.94%	11.94%	11.94%	11.94%	11.94%		
66	G51 Med Annual-Low Winter	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%		
67	G41 Med Annual-High Winter	15.08%	15.08%	15.08%	15.08%	15.08%	15.08%		
68	G52 High Annual-Low Winter	16.76%	16.76%	16.76%	16.76%	16.76%	16.76%		
69	G42 High Annual-High Winter	3.08%	3.08%	3.08%	3.08%	3.08%	3.08%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
72	REMAINING COMMODITY Excld Hedging	$ 153,724	$ 32,884	$ 6,796	$ 11,774	$ 44,718	$ 337,363	$ 13,997,930	$ 587,261
73	Res Heat	$ 51,942	$ 11,111	$ 2,296	$ 3,979	$ 15,110	$ 113,992	$ 6,476,431	$ 198,431
74	Res General	$ 1,730	$ 370	$ 77	$ 133	$ 503	$ 3,798	$ 73,093	$ 6,611
75	G50 Low Annual-Low Winter	$ 9,481	$ 2,028	$ 419	$ 726	$ 2,758	$ 20,807	$ 249,249	$ 36,219
76	G40 Low Annual-High Winter	$ 18,359	$ 3,927	$ 812	$ 1,406	$ 5,341	$ 40,291	$ 3,380,893	$ 70,136
77	G51 Med Annual-Low Winter	$ 18,531	$ 3,964	$ 819	$ 1,419	$ 5,391	$ 40,668	$ 331,532	$ 70,791
78	G41 Med Annual-High Winter	$ 23,182	$ 4,959	$ 1,025	$ 1,776	$ 6,744	$ 50,874	$ 2,805,577	$ 88,559
79	G52 High Annual-Low Winter	$ 25,771	$ 5,513	$ 1,139	$ 1,974	$ 7,497	$ 56,557	$ 122,070	$ 98,451
80	G42 High Annual-High Winter	$ 4,728	$ 1,011	$ 209	$ 362	$ 1,375	$ 10,376	$ 559,084	$ 18,062
81									
82	Residential	$ 53,673	$ 11,482	$ 2,373	$ 4,111	$ 15,613	$ 117,790	$ 6,549,525	$ 205,042
83	SALES HLF CLASSES	$ 53,783	$ 11,505	$ 2,378	$ 4,119	$ 15,645	$ 118,031	$ 702,851	$ 205,461
84	SALES LLF CLASSES	$ 46,269	$ 9,898	$ 2,045	$ 3,544	$ 13,460	$ 101,542	$ 6,745,554	$ 176,758

85	**REMAINING COMMODITY HEDGING COSTS**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
86	TOTAL REMAINING COMMODITY HEDGING	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,289	$ -
87	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,676	$ -
88	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ 309	$ -
89	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,005	$ -
90	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,085	$ -
91	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,227	$ -
92	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,413	$ -
93	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 102	$ -
94	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,472	$ -
95								$ -	$ -
96	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,985	$ -
97	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,334	$ -
98	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,971	$ -

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-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
100	TOTAL COMMODITY Excld Hedging	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,417,748	$ 2,090,615
101	Res Heat	$ 132,106	$ 88,015	$ 82,144	$ 87,720	$ 99,651	$ 216,766	$ 8,347,673	$ 706,402
102	Res General	$ 4,401	$ 2,932	$ 2,737	$ 2,922	$ 3,320	$ 7,222	$ 135,435	$ 23,534
103	G50 Low Annual-Low Winter	$ 24,113	$ 16,065	$ 14,993	$ 16,011	$ 18,189	$ 39,566	$ 590,802	$ 128,938
104	G40 Low Annual-High Winter	$ 46,694	$ 31,109	$ 29,034	$ 31,005	$ 35,222	$ 76,617	$ 4,042,293	$ 249,682
105	G51 Med Annual-Low Winter	$ 47,130	$ 31,400	$ 29,305	$ 31,295	$ 35,551	$ 77,333	$ 992,191	$ 252,013
106	G41 Med Annual-High Winter	$ 58,958	$ 39,281	$ 36,660	$ 39,149	$ 44,474	$ 96,742	$ 3,640,705	$ 315,265
107	G52 High Annual-Low Winter	$ 65,544	$ 43,669	$ 40,755	$ 43,522	$ 49,442	$ 107,548	$ 939,233	$ 350,480
108	G42 High Annual-High Winter	$ 12,025	$ 8,012	$ 7,477	$ 7,985	$ 9,071	$ 19,731	$ 729,416	$ 64,301
109									
110	Residential	$ 136,507	$ 90,948	$ 84,880	$ 90,642	$ 102,971	$ 223,988	$ 8,483,107	$ 729,937
111	SALES HLF CLASSES	$ 136,787	$ 91,134	$ 85,054	$ 90,828	$ 103,182	$ 224,447	$ 2,522,226	$ 731,431
112	SALES LLF CLASSES	$ 117,677	$ 78,402	$ 73,172	$ 78,139	$ 88,767	$ 193,091	$ 8,412,414	$ 629,248

113	**TOTAL HEDGING COMMODITY COSTS**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
114	TOTAL HEDGING COMMODITY	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,993	$ -
115	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,494	$ -
116	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ 569	$ -
117	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,432	$ -
118	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,849	$ -
119	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,016	$ -
120	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,903	$ -
121	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,547	$ -
122	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,184	$ -
123									
124	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,063	$ -
125	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,994	$ -
126	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,936	$ -

127	TOTAL COMMODITY	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
128	Res Heat	$ 132,106	$ 88,015	$ 82,144	$ 87,720	$ 99,651	$ 216,766	$ 8,384,167	$ 706,402
129	Res General	$ 4,401	$ 2,932	$ 2,737	$ 2,922	$ 3,320	$ 7,222	$ 136,004	$ 23,534
130	G50 Low Annual-Low Winter	$ 24,113	$ 16,065	$ 14,993	$ 16,011	$ 18,189	$ 39,566	$ 593,234	$ 128,938
131	G40 Low Annual-High Winter	$ 46,694	$ 31,109	$ 29,034	$ 31,005	$ 35,222	$ 76,617	$ 4,060,142	$ 249,682
132	G51 Med Annual-Low Winter	$ 47,130	$ 31,400	$ 29,305	$ 31,295	$ 35,551	$ 77,333	$ 996,207	$ 252,013
133	G41 Med Annual-High Winter	$ 58,958	$ 39,281	$ 36,660	$ 39,149	$ 44,474	$ 96,742	$ 3,656,608	$ 315,265
134	G52 High Annual-Low Winter	$ 65,544	$ 43,669	$ 40,755	$ 43,522	$ 49,442	$ 107,548	$ 942,780	$ 350,480
135	G42 High Annual-High Winter	$ 12,025	$ 8,012	$ 7,477	$ 7,985	$ 9,071	$ 19,731	$ 732,600	$ 64,301
136	Total Firm Sales	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,501,741	$ 2,090,615
137									
138	Residential	$ 136,507	$ 90,948	$ 84,880	$ 90,642	$ 102,971	$ 223,988	$ 8,520,171	$ 729,937
139	SALES HLF CLASSES	$ 136,787	$ 91,134	$ 85,054	$ 90,828	$ 103,182	$ 224,447	$ 2,532,220	$ 731,431
140	SALES LLF CLASSES	$ 117,677	$ 78,402	$ 73,172	$ 78,139	$ 88,767	$ 193,091	$ 8,449,350	$ 629,248
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								53.75%
144	SALES LLF CLASSES								46.25%

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 Utilities, Inc. Normal Winter Weather - Sales Service & Company Managed Sendout Commodity Volumes by Supply Source (Dth) May 2016 through October 2016							
Description	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Season
Pipeline Supplies							
Tennessee Production	308,702	147,866	110,097	112,646	164,122	318,930	1,162,363
Chicago	0	0	0	0	0	0	0
Algonquin Receipts	0	0	0	0	0	0	0
TGP Zone 6	6,613	0	0	0	0	63,554	70,166
Niagara	17,036	0	0	0	0	39,126	56,162
Iroquois Receipts	0	0	0	0	0	0	0
PNGTS Receipts	30,892	29,895	30,892	30,892	29,895	30,892	183,356
PNGTS Delivered	83,407	80,717	83,407	83,407	80,717	83,407	495,061
Maritimes Delivered	0	0	0	0	0	62,000	62,000
Subtotal Pipeline	446,649	258,478	224,395	226,944	274,734	597,909	2,029,109
Underground Storage							
Tenn Zone 4 Spot	75,194	72,768	75,194	75,194	72,768	75,194	446,312
Tennessee Storage	0	0	0	0	0	0	0
Tennesse Storage Path	75,194	72,768	75,194	75,194	72,768	75,194	446,312
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	75,194	72,768	75,194	75,194	72,768	75,194	446,312
Peaking Supplies							
Peaking Contract 1	0	0	0	0	0	0	0
Peaking Contract 2	0	0	0	0	0	0	0
Peaking Contract 3	0	0	0	0	0	0	0
Peaking Contract 4	0	0	0	0	0	0	0
LNG	2,201	2,130	2,201	2,201	2,130	2,201	13,064
Subtotal Peaking	2,201	2,130	2,201	2,201	2,130	2,201	13,064
Total Delivered (Dth)	524,044	333,376	301,790	304,339	349,632	675,304	2,488,485

Schedule 11B

Provided in the Winter 2015-16 Cost-of-Gas Filing

Schedule 11C

Northern Utilities, Inc. Normal Winter Weather - Sales Service & Company Managed Sendout Capacity Utilization by Supply Source May 2016 through October 2016			
Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	1,162,363	2,163,668	54%
Chicago and Iroquois	1,011,699	1,164,554	87%
Algonquin Receipts	0	226,431	0%
TGP Zone 6	70,166	0	
Niagara	56,162	421,187	13%
PNGTS Receipts	183,356	180,897	101%
PNGTS Delivered	495,061	495,061	100%
Maritimes Delivered	62,000	62,000	100%
Subtotal Pipeline	3,040,808	4,713,798	65%
Underground Storage			
Tenn Zone 4 Spot	446,312		
Tennessee Storage	0		
Tennesse Storage Path	446,312	441,522	101%
W10 AMA Spot	0		
Washington 10 Storage	0		
W10 Storage Path	0	4,965,635	0%
Subtotal Storage	446,312	5,407,157	8%
Peaking Supplies			
Peaking Contract 1	0	298,950	0%
Peaking Contract 2	0	0	
Peaking Contract 3	0	0	
Peaking Contract 4	0	0	
LNG	13,064	75,000	17%
Subtotal Peaking	13,064	373,950	3%
Total Delivered (Dth)	2,488,485	10,494,905	24%

Schedule 11D & Schedule 11E

Provided in the Winter 2015-16 Cost-of-Gas Filing

Schedule 12

Provided in the Winter 2015-16 Cost-of-Gas Filing

Schedule 13

Provided in the Winter 2015-16 Cost-of-Gas Filing

Schedule 14

Provided in the Winter 2015-16 Cost-of-Gas Filing

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER SEASON BALANCE
November 2014 - October 2015

	AMOUNT	
Summer Season Beginning Balance	$ (470,798)	SCHEDULE 2
May 2015 Adjustment	$ 92,603	SCHEDULE 2
Less: Reported Collections	$ (2,159,606)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$ 2,574,720	SCHEDULE 4
Add: Interest	$ (13,658)	SCHEDULE 2
Summer Season Ending Balance	$ 23,260	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER SEASON ACCOUNTS
November 2014 - October 2015
Acct 191.10

	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
SUMMER SEASON													
Summer Season Account Beginning Balance	$ (470,798)												$ (470,798)
Adjustment*	$ 92,603												$ 92,603
Adjusted Seasonal Beginning Balance	$ (378,195)	$ (541,942)	$ (539,707)	$ (540,888)	$ (542,405)	$ (543,631)	$ (545,220)	$ (695,700)	$ (451,113)	$ (309,941)	$ (118,739)	$ (43,080)	$ (378,195)
Plus: Cost of Firm Gas (Schedule 4)	$ 10,170	$ -	$ -	$ -	$ -	$ -	$ 429,520	$ 501,366	$ 323,323	$ 393,784	$ 384,663	$ 531,893	$ 2,574,720
Less: Reported Collections (Schedule 3)	$ (172,672)	$ 3,697	$ 281	$ (53)	$ 243	$ (116)	$ (578,323)	$ (255,228)	$ (181,121)	$ (202,003)	$ (308,785)	$ (465,527)	$ (2,159,606)
Summer Season Account Ending Balance	$ (540,697)	$ (538,244)	$ (539,426)	$ (540,940)	$ (542,162)	$ (543,747)	$ (694,022)	$ (449,562)	$ (308,912)	$ (118,160)	$ (42,861)	$ 23,287	$ 36,918
Month's Average Balance	$ (459,446)	$ (540,093)	$ (539,567)	$ (540,914)	$ (542,284)	$ (543,689)	$ (619,621)	$ (572,631)	$ (380,012)	$ (214,050)	$ (80,800)	$ (9,897)	
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	$ (1,244)	$ (1,463)	$ (1,461)	$ (1,465)	$ (1,469)	$ (1,472)	$ (1,678)	$ (1,551)	$ (1,029)	$ (580)	$ (219)	$ (27)	$ (13,658)
Summer Season Account Ending Balance w/int	$ (541,942)	$ (539,707)	$ (540,888)	$ (542,405)	$ (543,631)	$ (545,220)	$ (695,700)	$ (451,113)	$ (309,941)	$ (118,739)	$ (43,080)	$ 23,260	$ 23,260

*Adjustment reflects revised ATV costs from May through October 2014.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2014 - October 2015

	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
Accrued Revenue	$ (663,191)	$ -	$ -	$ -	$ -	$ -	$ 289,862	$ (142,158)	$ (63,353)	$ 3,846	$ 79,368	$ 103,519	$ (392,107)
Billed Revenue	$ 835,863	$ (3,697)	$ (281)	$ 53	$ (243)	$ 116	$ 288,461	$ 397,385	$ 244,474	$ 198,157	$ 229,417	$ 362,009	$ 2,551,714
Calendarized Revenue	$ 172,672	$ (3,697)	$ (281)	$ 53	$ (243)	$ 116	$ 578,323	$ 255,228	$ 181,121	$ 202,003	$ 308,785	$ 465,527	$ 2,159,606

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2014 - October 2015

Commodity Costs	**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 Summer Season**
Barclays Bank	$ 68,211	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 68,211**
Cairn & Sons	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,115	$ -	$ -	$ -	$ -	**$ 3,115**
Chesapeak Energy Marketing	$ 33,956	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 33,956**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 238,283	$ 269,131	$ 245,714	$ 207,465	$ 232,351	**$ 1,192,943**
Emera Energy Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,216	$ -	$ -	$ -	$ -	**$ 8,216**
Sequent Energy Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,462	$ -	$ -	$ -	$ -	**$ 25,462**
Shell Energy North America	$ 280,646	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,510	$ -	**$ 321,155**
Tenaska Marketing Ventures	$ 153,194	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 153,194**
Subtotal - Commodity	$ 536,007	$ -	$ -	$ -	$ -	$ -	$ -	$ 275,076	$ 269,131	$ 245,714	$ 247,974	$ 232,351	**$ 1,806,253**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 120	$ 99	$ 93	$ 90	$ 73	$ 160	**$ 635**
Portland	$ 22	$ -	$ -	$ -	$ -	$ -		$ 17	$ 16	$ 16	$ 15	$ 16	**$ 101**
Tennessee	$ 10,315	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,070	$ 8,961	$ 8,442	$ 8,140	$ 8,497	**$ 53,425**
Subtotal - Commodity Transportation	$ 10,337	$ -	$ -	$ -	$ -	$ -	$ 120	$ 9,185	$ 9,070	$ 8,547	$ 8,228	$ 8,673	**$ 54,161**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 281,047	$ 349,371	$ 254,172	$ 256,110	$ 240,202	$ 507,911	**$ 1,888,813**
Commodity Cost Reversals	$ (551,975)	$ -	$ -	$ -	$ -	$ -	$ -	$ (281,047)	$ (349,371)	$ (254,172)	$ (256,110)	$ (240,202)	**$ (1,932,877)**
Subtotal - Estimates	$ (551,975)	$ -	$ -	$ -	$ -	$ -	$ 281,047	$ 68,324	$ (95,199)	$ 1,938	$ (15,908)	$ 267,709	**$ (44,064)**
Subtotal - Supply	$ (5,631)	$ -	$ -	$ -	$ -	$ -	$ 281,167	$ 352,585	$ 183,002	$ 256,199	$ 240,294	$ 508,733	**$ 1,816,350**
Withdrawal - Underground Storage	$ 10	$ -	$ -	$ -	$ -	$ -	$ 54	$ 13	$ 252	$ 147	$ -	$ 226	**$ 701**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 852	$ (3,330)	$ (6,803)	$ (3,959)	$ 2,288	$ 25,688	**$ 14,737**
Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (50,801)	**$ (50,801)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,248)	$ (379)	$ (5,399)	$ (816)	$ (5,378)	$ (5,620)	**$ (23,840)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,383	$ 13,166	$ 13,006	$ 11,470	$ 9,236	$ 7,500	**$ 68,761**
Transportation Charges	$ 10,171	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (48)	$ (8,570)	$ (1,089)	$ 570	**$ 1,034**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal - Other Commodity	$ 10,181	$ -	$ -	$ -	$ -	$ -	$ 9,041	$ 9,469	$ 1,009	$ (1,727)	$ 5,057	$ (22,437)	**$ 10,593**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (93,714)	**$ (93,714)**
Sales for Resale Reversals	$ 5,620	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,620**
Subtotal - Estimates	$ 5,620	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (93,714)	**$ (88,094)**
Total Commodity Costs	**$ 10,170**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 290,208**	**$ 362,054**	**$ 184,011**	**$ 254,472**	**$ 245,352**	**$ 392,582**	**$ 1,738,849**
Demand Costs													
Direct Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,333	$ 123,333	$ 123,333	$ 123,333	$ 123,333	$ 123,333	**$ 739,996**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,979	$ 15,979	$ 15,979	$ 15,979	$ 15,979	$ 15,979	**$ 95,875**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 139,312**	**$ 139,312**	**$ 139,312**	**$ 139,312**	**$ 139,312**	**$ 139,312**	**$ 835,871**
Total Gas Costs	**$ 10,170**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 429,520**	**$ 501,366**	**$ 323,323**	**$ 393,784**	**$ 384,663**	**$ 531,893**	**$ 2,574,720**

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2014 - October 2015

Commodity Volumes:	**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 Summer Season**
Barclays Bank	[redacted]												
Cairn & Sons	[redacted]												
Chesapeak Energy Marketing	[redacted]												
DTE Energy Trading	[redacted]												
Emera Energy Services	[redacted]												
Sequent Energy Management	[redacted]												
Shell Energy North America	[redacted]												
Tenaska Marketing Ventures	[redacted]												
Subtotal - Commodity Supply	[redacted]												
Granite	[redacted]												
Portland	[redacted]												
Tennessee	[redacted]												
Subtotal - Commodity Transportation	[redacted]												
Commodity Volume Estimates	[redacted]												
Commodity Volume Reversals	[redacted]												
Subtotal - Estimates	[redacted]												
Subtotal - Supply	[redacted]												
Withdrawal - Underground Storage	[redacted]												
Withdrawal - LNG Vaporization	[redacted]												
ATV Reconciliation	[redacted]												
Off System Sales	[redacted]												
Net OBA Adjustment	[redacted]												
LNG Boiloff	[redacted]												
Transportation Charges	[redacted]												
Hedging Costs	[redacted]												
Propane	[redacted]												
Subtotal - Other Commodity	[redacted]												
Sales for Resale Estimates	[redacted]												
Sales for Resale Reversals	[redacted]												
Subtotal - Estimates	[redacted]												
Total Commodity Volumes	[redacted]												

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2014 - October 2015

Commodity Costs per Unit:	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 Summer Season
Barclays Bank	[redacted]												
Cairn & Sons													
Chesapeak Energy Marketing													
DTE Energy Trading													
Emera Energy Services													
Sequent Energy Management													
Shell Energy North America													
Tenaska Marketing Ventures													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Costs per unit													

NORTHERN UTILITIES, INC. - MAINE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2014 - October 2015

Commodity Costs:	**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 Summer Season**
Barclays Bank	$ 78,543	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 78,543**
Cairn & Sons	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Chesapeak Energy Marketing	$ 39,099	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 39,099**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 387,297	$ 423,613	$ 442,367	$ 392,317	$ 390,407	**$ 2,036,000**
Emera Energy Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,354	$ -	$ -	$ -	$ -	**$ 13,354**
Sequent Energy Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,385	$ -	$ -	$ -	$ -	**$ 41,385**
Shell Energy North America	$ 323,153	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 76,604	$ -	**$ 399,757**
Tenaska Marketing Ventures	$ 176,398	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 176,398**
Subtotal - Commodity Supply	$ 617,193	$ -	$ -	$ -	$ -	$ -	$ -	$ 442,035	$ 423,613	$ 442,367	$ 468,921	$ 390,407	**$ 2,784,536**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 196	$ 155	$ 167	$ 169	$ 123	$ 277	**$ 1,087**
Portland	$ 26	$ -	$ -	$ -	$ -	$ -	$ -	$ 27	$ 26	$ 28	$ 28	$ 26	**$ 161**
Tennessee	$ 11,877	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,742	$ 14,105	$ 15,199	$ 15,393	$ 14,277	**$ 85,592**
Subtotal - Commodity Transportation	$ 11,903	$ -	$ -	$ -	$ -	$ -	$ 196	$ 14,924	$ 14,298	$ 15,396	$ 15,544	$ 14,581	**$ 86,841**
Commodity Cost Estimates		$ -	$ -	$ -	$ -	$ -	$ 456,804	$ 549,911	$ 457,594	$ 484,305	$ 404,684	$ 877,931	**$ 3,231,229**
Commodity Cost Reversals	$ (635,579)	$ -	$ -	$ -	$ -	$ -	$ -	$ (456,804)	$(549,911)	$(457,594)	$(484,305)	$ (404,684)	**$ (2,988,877)**
Subtotal - Estimates	$ (635,579)	$ -	$ -	$ -	$ -	$ -	$ 456,804	$ 93,107	$ (92,317)	$ 26,711	$ (79,621)	$ 473,247	**$ 242,352**
Subtotal - Supply	$ (6,484)	$ -	$ -	$ -	$ -	$ -	$ 457,000	$ 550,066	$ 345,593	$ 484,474	$ 404,844	$ 878,234	$ 3,113,729
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization	$ 12	$ -	$ -	$ -	$ -	$ -	$ 87	$ 20	$ 454	$ 279	$ -	$ 390	**$ 1,241**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,385	$ (5,241)	$ (12,247)	$ (7,486)	$ 3,884	$ 44,402	**$ 24,697**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,359)	**$ (85,359)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,155)	$ (597)	$ (9,720)	$ (1,543)	$ (9,036)	$ (9,714)	**$ (40,765)**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,377	$ 20,723	$ 23,416	$ 21,690	$ 15,519	$ 12,964	**$ 117,689**
Hedging Costs	$ 11,711	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (75)	$ (15,429)	$ (2,059)	$ 958	**$ (4,895)**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal - Other Commodity	$ 11,723	$ -	$ -	$ -	$ -	$ -	$ 15,221	$ 15,486	$ 2,348	$ (1,991)	$ 8,799	$ (35,852)	**$ 15,734**
Sales for Resale Estimates		$ -	$ -	`)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (161,985)	**(161,985)**
Sales for Resale Reversals	$ 6,472	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**6,472**
Subtotal - Estimates	$ 6,472	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (161,985)	**$ (155,513)**
Total Commodity Costs	**$ 11,711**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 472,221**	**$ 565,552**	**$ 347,942**	**$ 482,484**	**$ 413,643**	**$ 680,397**	**$ 2,973,950**
Demand Costs													
Direct Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 129,313	$ 129,313	$ 129,314	$ 129,313	$ 129,313	$ 129,313	$ 775,881
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,847	$ 4,847	$ 4,847	$ 4,847	$ 4,847	$ 4,847	$ 29,081
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 134,160**	**$ 134,160**	**$ 134,160**	**$ 134,160**	**$ 134,160**	**$ 134,160**	**$ 804,961**
Total Gas Costs	**$ 11,711**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 606,381**	**$ 699,713**	**$ 482,102**	**$ 616,644**	**$ 547,803**	**$ 814,558**	**$ 3,778,911**

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2014 - October 2015

Commodity Volumes:	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 Summer Season
Barclays Bank	[redacted]												
Cairn & Sons													
Chesapeak Energy Marketing													
DTE Energy Trading													
Emera Energy Services													
Sequent Energy Management													
Shell Energy North America													
Tenaska Marketing Ventures													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Volumes													

Schedule 15

FORM III
Schedule 4
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REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2014 - October 2015

Commodity Costs per Unit:	**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 Summer Season**
Barclays Bank	[redacted]												
Cairn & Sons													
Chesapeak Energy Marketing													
DTE Energy Trading													
Emera Energy Services													
Sequent Energy Management													
Shell Energy North America													
Tenaska Marketing Ventures													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Costs per unit													

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2014 - October 2015

Commodity Costs:	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 Summer Season
Barclays Bank	$ 146,754	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 146,754**
Cairn & Sons	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,115	$ -	$ -	$ -	$ -	**$ 3,115**
Chesapeak Energy Marketing	$ 73,055	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 73,055**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 625,580	$ 692,744	$ 688,081	$ 599,782	$ 622,758	**$ 3,228,944**
Emera Energy Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,570	$ -	$ -	$ -	$ -	**$ 21,570**
Sequent Energy Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,846	$ -	$ -	$ -	$ -	**$ 66,846**
Shell Energy North America	$ 603,799	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,114	$ -	**$ 720,913**
Tenaska Marketing Ventures	$ 329,592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 329,592**
Subtotal - Commodity Supply	$ 1,153,200	$ -	$ -	$ -	$ -	$ -	$ -	$ 717,111	$ 692,744	$ 688,081	$ 716,896	$ 622,758	$ 4,590,789
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 316	$ 254	$ 260	$ 259	$ 196	$ 438	**$ 1,722**
Portland	$ 48	$ -	$ -	$ -	$ -	$ -	$ -	$ 43	$ 42	$ 43	$ 44	$ 42	**$ 262**
Tennessee	$ 22,191	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,812	$ 23,066	$ 23,641	$ 23,533	$ 22,774	**$ 139,017**
Subtotal - Commodity Transportation	$ 22,239	$ -	$ -	$ -	$ -	$ -	$ 316	$ 24,109	$ 23,368	$ 23,944	$ 23,772	$ 23,253	**$ 141,002**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 737,851	$ 899,282	$ 711,766	$ 740,415	$ 644,886	$ 1,385,842	**$ 5,120,042**
Commodity Cost Reversals	$ (1,187,554)	$ -	$ -	$ -	$ -	$ -	$ -	$ (737,851)	$ (899,282)	$ (711,766)	$ (740,415)	$ (644,886)	**$ (4,921,754)**
Subtotal - Estimates	$ (1,187,554)	$ -	$ -	$ -	$ -	$ -	$ 737,851	$ 161,431	$ (187,516)	$ 28,649	$ (95,529)	$ 740,956	$ 198,288
Subtotal - Supply	$ (12,114)	$ -	$ -	$ -	$ -	$ -	$ 738,167	$ 902,651	$ 528,596	$ 740,673	$ 645,139	$ 1,386,967	$ 4,930,079
Withdrawal - Underground Storage	$ 22	$ -	$ -	$ -	$ -	$ -	$ 141	$ 33	$ 706	$ 426	$ -	$ 616	**$ 1,943**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,238	$ (8,571)	$ (19,050)	$ (11,444)	$ 6,171	$ 70,090	**$ 39,434**
Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (136,160)	**$ (136,160)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,403)	$ (977)	$ (15,119)	$ (2,358)	$ (14,413)	$ (15,334)	**$ (64,605)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,760	$ 33,889	$ 36,422	$ 33,160	$ 24,755	$ 20,465	**$ 186,450**
Transportation Charges	$ 21,882	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (123)	$ (23,999)	$ (3,148)	$ 1,528	**$ (3,861)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Propane	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 527**	**$ 581**	**$ 521**	**$ 498**	**$ 491**	**$ 507**	$ 3,125
Subtotal - Other Commodity	$ 21,903	$ -	$ -	$ -	$ -	$ -	$ 24,262	$ 24,956	$ 3,357	$ (3,718)	$ 13,856	$ (58,289)	$ 26,327
Sales for Resale Estimates													
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (255,699)	$ (255,699)
Subtotal - Estimates	$ 12,092	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 12,092**
	$ 12,092	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (255,699)	$ (243,607)
Total Commodity Costs	$ 21,881	$ -	$ -	$ -	$ -	$ -	$ 762,429	$ 927,607	$ 531,952	$ 736,955	$ 658,995	$ 1,072,979	$ 4,712,798
Demand Costs													
Direct Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 252,646	$ 252,646	$ 252,646	$ 252,646	$ 252,646	$ 252,646	$ 1,515,876
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,826	$ 20,826	$ 20,826	$ 20,826	$ 20,826	$ 20,826	$ 124,956
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 273,472**	**$ 273,472**	**$ 273,472**	**$ 273,472**	**$ 273,472**	**$ 273,472**	**$ 1,640,832**
Total Costs	**$ 21,881**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,035,901**	**$ 1,201,079**	**$ 805,425**	**$ 1,010,427**	**$ 932,467**	**$ 1,346,451**	**$ 6,353,631**

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2014 - October 2015

Commodity Volumes:	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 Summer Season
Barclays Bank	[redacted]												
Cairn & Sons													
Chesapeak Energy Marketing													
DTE Energy Trading													
Emera Energy Services													
Sequent Energy Management													
Shell Energy North America													
Tenaska Marketing Ventures													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Volumes													

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2015 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2014 - October 2015

Commodity Costs per Unit:	**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 Summer Season**
Barclays Bank	[redacted]												
Cairn & Sons													
Chesapeak Energy Marketing													
DTE Energy Trading													
Emera Energy Services													
Sequent Energy Management													
Shell Energy North America													
Tenaska Marketing Ventures													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Costs per unit													

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2015 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2014 - October 2015

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	Total
Throughput IN													
BTU Factor	1.028	1.032	1.038	1.04	1.033	1.029	1.029	1.028	1.027	1.028	1.027	1.030	
GST Meter Throughput (MCF)	732,361	900,908	1,196,940	1,180,897	1,001,995	615,556	376,431	361,552	336,560	333,344	351,337	531,243	7,919,124
Salem Meter (MCF)	43,867	59,116	83,871	85,696	66,078	32,039	14,557	12,565	10,691	10,918	11,600	23,646	454,644
GST Meter Throughpurt (DTH)	752,867	929,737	1,242,424	1,228,133	1,035,061	633,407	387,347	371,675	345,647	342,678	360,823	547,180	8,176,980
Salem Meter (DTH)	45,095	61,008	87,058	89,124	68,259	32,968	14,979	12,917	10,980	11,224	11,913	24,355	469,880
LNG/Propane													-
Total Throughput	797,962	990,745	1,329,482	1,317,257	1,103,319	666,375	402,327	384,592	356,627	353,901	372,736	571,536	8,646,859
Throughput OUT													
Residential Gas													
Charged	123,697	237,569	323,308	386,936	328,732	214,074	84,367	52,812	37,546	33,444	34,545	59,775	1,916,805
Uncharged Current	132,335	179,357	185,433	182,273	157,295	69,627	60,434	28,188	20,985	22,048	44,509	81,401	1,163,883
Uncharged Prior	(63,900)	(132,335)	(179,357)	(185,433)	(182,273)	(157,295)	(69,627)	(60,434)	(28,188)	(20,985)	(22,048)	(44,509)	(1,146,383)
Total Residential Gas	**192,132**	**284,591**	**329,384**	**383,776**	**303,755**	**126,406**	**75,174**	**20,566**	**30,343**	**34,507**	**57,006**	**96,667**	1,934,306
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	151,660	289,851	400,372	489,550	385,211	245,453	104,967	79,431	53,967	48,384	60,351	84,484	2,393,681
Uncharged Current	145,948	213,753	226,055	230,028	187,668	86,214	73,159	42,396	30,163	31,897	50,553	88,642	1,406,476
Uncharged Prior	(61,255)	(145,948)	(213,753)	(226,055)	(230,028)	(187,668)	(86,214)	(73,159)	(42,396)	(30,163)	(31,897)	(50,553)	(1,379,089)
Total C/I Gas	**236,352**	**357,657**	**412,674**	**493,522**	**342,852**	**143,999**	**91,912**	**48,668**	**41,734**	**50,118**	**79,007**	**122,574**	2,421,068
Transportation													
Charged	335,994	392,007	453,727	454,504	479,889	377,945	274,036	274,115	286,042	246,513	268,368	319,883	4,163,023
Uncharged Current	211,590	210,011	206,006	180,399	194,103	119,357	124,816	96,572	108,407	100,793	123,959	192,485	1,868,497
Uncharged Prior	(128,845)	(211,590)	(210,011)	(206,006)	(180,399)	(194,103)	(119,357)	(124,816)	(96,572)	(108,407)	(100,793)	(123,959)	(1,804,857)
Total Transportation	**418,739**	**390,427**	**449,722**	**428,898**	**493,593**	**303,200**	**279,495**	**245,871**	**297,877**	**238,899**	**291,534**	**388,410**	**4,226,663**
Company Use	**112**	**233**	**349**	**415**	**373**	**237**	**98**	**72**	**58**	**117**	**136**	**89**	**2,289**
Total Throughput OUT	**847,336**	**1,032,908**	**1,192,129**	**1,306,611**	**1,140,572**	**573,841**	**446,679**	**315,177**	**370,012**	**323,641**	**427,682**	**607,739**	**8,584,325**
Total Throughput IN	**797,962**	**990,745**	**1,329,482**	**1,317,257**	**1,103,319**	**666,375**	**402,327**	**384,592**	**356,627**	**353,901**	**372,736**	**571,536**	**8,646,859**
Difference IN/OUT	(49,373)	(42,163)	137,353	10,646	(37,252)	92,535	(44,352)	69,415	(13,385)	30,260	(54,946)	(36,203)	62,534
%													0.72%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2014 - October 2015

SUMMER SEASON - Acct 182.21

		BEGINNING BALANCE	WORKING CAP ALLOWANCE (2)	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
Initial November 2014	$	(387)									
Adjustment (1)	$	76									
Revised Beginning Balance	$	(311)	8	0.0824%	(144)	(135)	(446)	(378)	3.25%	(1)	(447)
December	$	(447)	0	0.0824%	3	3	(444)	(445)	3.25%	(1)	(445)
January 2015	$	(445)	0	0.0824%	0	0	(444)	(445)	3.25%	(1)	(446)
February	$	(446)	0	0.0824%	(0)	(0)	(446)	(446)	3.25%	(1)	(447)
March	$	(447)	0	0.0824%	0	0	(447)	(447)	3.25%	(1)	(448)
April	$	(448)	0	0.0824%	(0)	(0)	(448)	(448)	3.25%	(1)	(449)
May	$	(449)	354	0.0824%	(543)	(189)	(638)	(544)	3.25%	(1)	(640)
June	$	(640)	413	0.0824%	(256)	157	(483)	(561)	3.25%	(2)	(484)
July	$	(484)	266	0.0824%	(168)	99	(385)	(435)	3.25%	(1)	(386)
August	$	(386)	324	0.0824%	(228)	97	(290)	(338)	3.25%	(1)	(291)
September	$	(291)	317	0.0824%	(355)	(38)	(329)	(310)	3.25%	(1)	(329)
October	$	(329)	438	0.0824%	(539)	(100)	(430)	(379)	3.25%	(1)	(431)

(1) Adjustment reflects updated commodity costs due to revised ATV costs for May thorugh October 2014.

(2) 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 2014 - October 2015

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE	ACUTAL 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 = B + C	E = A + D	F = (A + E) / 2	G	H = (F *G) / 12	I = E + H
November 2014	$921	4,310	(731)	3,578	4,499	2,710	3.25%	7	4,506
December	$4,506	1,675	17	1,692	6,198	5,352	3.25%	14	6,213
January 2015	$6,213	719	0	720	6,932	6,573	3.25%	18	6,950
February	$6,950	1,626	(0)	1,626	8,576	7,763	3.25%	21	8,597
March	$8,597	618	1	619	9,216	8,907	3.25%	24	9,240
April	$9,240	740	(1)	739	9,980	9,610	3.25%	26	10,006
May	$10,006	838	(7,639)	(6,801)	3,205	6,605	3.25%	18	3,223
June	$3,223	732	(3,623)	(2,891)	332	1,777	3.25%	5	337
July	$337	1,701	(3,151)	(1,450)	(1,114)	(388)	3.25%	(1)	(1,115)
August	($1,115)	2,374	(3,424)	(1,050)	(2,164)	(1,639)	3.25%	(4)	(2,169)
September	($2,169)	1,408	(5,131)	(3,722)	(5,891)	(4,030)	3.25%	(11)	(5,902)
October	($5,902)	662	(7,508)	(6,846)	(12,748)	(9,325)	3.25%	(25)	(12,773)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2015

	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	TOTAL
Forecast Bill Month Sales	226,863	133,248	81,610	84,149	84,225	127,036	737,131
Actual Sales	189,334	132,243	91,513	81,828	94,895	144,258	734,072
Difference	(37,529)	(1,005)	9,903	(2,321)	10,670	17,222	(3,059)
Add:	-	-	-	-	-	-	
Volume Variance due to Weather							
Normal Cal. Month Actual Sales							-
Actual Sales	189,334	132,243	91,513	81,828	94,895	144,258	734,072
Weather Variance	(189,334)	(132,243)	(91,513)	(81,828)	(94,895)	(144,258)	(734,072)
Total Variance Excluding Weather (excl weather effect)	(226,863)	(133,248)	(81,610)	(84,149)	(84,225)	(127,036)	(737,131)
Variance-difference due to meter count							121,396
-difference in load pattern							(124,518)
SALES							(3,122)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2015

	NORMAL MMBtu			METERS		
	2015 Forecast	2015 Actual	Difference	2015 Forecast	2015 Actual	Difference
Res Heat	321,358	292,468	(28,890)	135,735	137,452	1,717
Res General	9,533	10,020	487	9,911	8,867	(1,044)
Total Res	330,891	302,488	(28,403)	145,646	146,319	673
G-40	117,029	91,810	(25,219)	25,371	25,346	(25)
G-50	58,970	65,958	6,988	4,404	4,652	248
G-41	120,602	106,722	(13,880)	2,100	2,692	592
G-51	79,925	86,823	6,898	719	849	130
G-42	15,834	25,565	9,731	29	83	54
G-52	13,943	54,705	40,762	6	22	16
Total C & I	406,303	431,584	25,281	32,629	33,644	1,015
Total Company	737,194	734,072	(3,122)	178,275	179,963	1,688

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2015 Forecast	2015 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.37	2.13	(0.24)	4,066	(32,956)	(28,890)	-8.99%
Res General	0.96	1.13	0.17	(1,004)	1,491	487	5.11%
Total Res	3.33	3.26	(0.07)	3,062	(31,465)	(28,403)	-8.58%
G-40	4.61	3.62	(0.99)	(116)	(25,103)	(25,219)	-21.55%
G-50	13.39	14.18	0.79	3,317	3,671	6,988	11.85%
G-41	57.43	39.64	(17.78)	33,995	(47,874)	(13,880)	-11.51%
G-51	111.19	102.27	(8.92)	14,473	(7,575)	6,898	8.63%
G-42	546.00	308.01	(237.99)	29,484	(19,753)	9,731	61.45%
G-52	2,323.83	2,486.61	162.78	37,181	3,581	40,762	292.35%
Total C & I	12.45	12.83	0.38	118,334	(93,053)	25,281	6.22%
Total Company	4.14	4.08	(0.06)	121,396	(124,518)	(3,122)	-0.42%

Attachment D

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2014-2015 ANNUAL RECONCILIATION
SUPPLIER REFUNDS
Period Ending October 31, 2015
ANNUAL DEMAND - Acct 242.90.10

	BEGINNING BALANCE	REFUND ADDITIONS	REFUND COLLECTIONS(1)	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE(2)	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D = A + B + C	E = (A + D) / 2	F	G = E * (F / 12)	H = D + G
November 2014*	$ (1,685)	$ -	21,159	19,475	8,895	3.25%	24	19,499
December	$ 19,499	$ -	(94)	19,405	19,452	3.25%	53	19,457
January 2015	$ 19,457	$ -	(62)	19,395	19,426	3.25%	53	19,448
February	$ 19,448	$ -	(3)	19,445	19,446	3.25%	53	19,498
March	$ 19,498	$ -	(28)	19,469	19,483	3.25%	53	19,522
April	$ 19,522	$ (10,420,309)	3	(10,400,784)	(5,190,631)	1.56%	(6,726)	(10,407,511)
May	$ (10,407,511)	$ -	24,215	(10,383,296)	(10,395,403)	1.56%	(13,505)	(10,396,801)
June	$ (10,396,801)	$ -	24,214	(10,372,587)	(10,384,694)	1.56%	(13,509)	(10,386,096)
July	$ (10,386,096)	$ -	26,232	(10,359,864)	(10,372,980)	1.56%	(13,511)	(10,373,375)
August	$ (10,373,375)	$ -	24,213	(10,349,162)	(10,361,268)	1.45%	(12,485)	(10,361,647)
September	$ (10,361,647)	$ -	24,191	(10,337,456)	(10,349,552)	1.45%	(12,523)	(10,349,979)
October	$ (10,349,979)	$ -	24,213	(10,325,766)	(10,337,873)	1.45%	(12,449)	(10,338,215)
Totals			168,252				(84,473)	

*Reflects initial balance of $0 plus additional interest of ($1,685).
Interest charge related to timing differences in the transfer of October 31, 2014 balance to the Demand and Commodity account.

(1): Refund Collections from May through October reflect transfer of PNGTS refund dollars to the Demand and Commodity account in accordance with Order No. 25,836 in Docket No. 15-393.

(2): Interest Charge on Supplier Refund resulting from PNGTS rate case is calculated at the Company's short term borrowing rate effective April 1, 2015, per Order No. 26,836 in Docket No. DG 15 393.

ANNUAL COMMODITY - Acct 242.90.01

	BEGINNING BALANCE	REFUND ADDITIONS	REFUND COLLECTIONS	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D = A + B + C	E = (A + D) / 2	F	G = E * (F / 12)	H = D + G
November 2014*	$ -		-	0	0	3.25%	0	0
December	$ -		0	0	0	3.25%	0	0
January 2015	$ -		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 2015-16 Cost-of-Gas Filing

Schedule 17

Provided in the Winter 2015-16 Cost-of-Gas Filing

Schedule 18

Provided in Winter 2015-16 Cost-of-Gas Filing

Schedule 19

Provided in Winter 2015-16 Cost-of-Gas Filing

Schedule 20

Hedging Plan for Winter 2017-18
Total Company

		Winter Season					
		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Total Contracts
	Strike Prices*	$3.400	$3.500	$3.750	$3.750	$3.750	
Scheduled Option Purchases	04/28/16	12					12
	05/27/16		20				20
	06/28/16			29			29
	07/28/16				30		30
	08/29/16					25	25
	09/28/16						0
	10/27/16						0
	11/28/16						0
	12/29/16						0
	01/27/17						0
	02/24/17						0
	03/29/17						0
Expiration Schedule	04/27/17						0
	05/29/17						0
	06/28/17						0
	07/27/17						0
	08/29/17						0
	09/28/17						0
	10/27/17	-12					-12
	11/28/17		-20				-20
	12/28/17			-29			-29
	01/29/18				-30		-30
	02/26/18					-25	-25
	03/29/18						0
	Scheduled	12	20	29	30	25	116

Futures Price*	$2.774	$2.910	$3.008	$2.990	$2.930	
7.50%	$0.2081	$0.2183	$0.2256	$0.2243	$0.2198	
Option Price	$0.1778	$0.2101	$0.2055	$0.2234	$0.2134	
Option Budget	$21,336	$42,020	$59,595	$67,020	$53,350	$243,321

* Futures and strike prices shown reflect market prices on February 09, 2016. Actual strike prices will reflect transactions made.

Northern proposes an option budget equal to 7.5 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.

Comparison of Hedging Program Budget Alternatives
Program Period: November 2017 - March 2018

No. Contracts: 116

Budget Percentage	Option Budget	Option Budget Delta	Cost per Dth	Average Strike Price	Strike Price Delta	Break-Even Price
2.5%	$ 82,004		$ 0.07	$ 5.17		$ 5.24
5.0%	$ 154,572	$ 72,568	$ 0.13	$ 4.23	$ (0.95)	$ 4.36
7.5%	$ 243,321	$ 88,749	$ 0.21	$ 3.67	$ (0.56)	$ 3.88
10.0%	$ 319,520	$ 76,199	$ 0.28	$ 3.37	$ (0.30)	$ 3.65

Notes:

Each option contract equals 10,000 Dth
Average Strike Price projections reflect NYMEX trading of European options on February 9, 2016
Contracts that settle below actual Strike Prices expire worthless
Contracts that settle above actual Strike Prices pay the delta between the Strike Price and settle price
Break-Even Price equals Strike Price plus Cost per Dth

3-Year Outlook for Winter 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 2017-18			WINTER 2018-19			WINTER 2019-20		
1	Sendout Requirement (Nov-Mar)	5,849,688			6,010,393			6,123,540		
2	Target Hedged Volume (70%)	4,094,781	70%		4,207,275	70%		4,286,478	70%	
3	Washington 10 Storage	2,743,722	47%		2,743,722	46%		2,743,722	45%	
4	Tennessee Storage	186,515	3%		186,515	3%		186,515	3%	
5	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
6	Physically Hedged Volume (=3+4+5)	2,930,237	50%		2,930,237	49%		2,930,237	48%	
7	Financial Hedge Volume (=2-6)	1,160,000	20%	116	1,280,000	21%	128	1,360,000	22%	136
8	Total Hedged Volume (=6+7)	4,090,237	70%		4,210,237	70%		4,290,237	70%	

Bill Impact Summary
Hedging Plan Period: November 2017 - March 2018

The table below summarizes the total bill impact for a typical residential customer under a variety of scenarios. Bill impact scenarios include a "Baseline" which assumes no program costs, the "Options Budget" which reflects the expected cost of options, a "Break-Even" which shows the amount underlying futures contracts must appreciate above the strike prices to offset the Options Budget, and expected impacts assuming the futures contracts expire at prices that are various percentages above the strike prices.

Scenario	Net (Cost) / Value	Typical Bill	Typical Bill Impact	PCT Impact Relative to Baseline
Baseline (No Hedging Activity)	$0	$1,017.43		0.00%
Options Budget	($243,321)	$1,021.42	$3.99	0.39%
Expire 1% over Strike Price	($200,741)	$1,024.71	$3.29	0.32%
Expire 5% over Strike Price	($30,421)	$1,025.21	$0.50	0.05%
Break-Even 5.7% over Strike Price	$0	$1,025.21	$0.00	0.00%
Expire 10% over Strike Price	$182,479	$1,022.22	($2.99)	-0.29%
Expire 20% over Strike Price	$608,279	$1,012.25	($9.97)	-0.98%

Rate Impact based on projected 2015-2016 winter demand of 47,102,528 therms.
Typical Bill based on projected costs for the 2015-2016 Winter Period.
Typical Bill Impact is based on typical residential usage of 772 ccf during Nov - Apr.

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	$ 8,968,294
Storage Demand	$ 24,942,854
Peaking Demand	$ 5,475,642
Subtotal Demand	$ 39,386,790
Capacity Release (Credit)	$ (64,987)
Asset Management (Credit)	$ (9,565,000)
Total Net Demand Costs	$ 29,756,803

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	1,453,194	1,288,023	1,237,486	1,128,257	1,284,982	1,141,241	621,751	456,059	431,653	439,435	483,114	716,558	10,681,751
Rank	1	2	4	6	3	5	8	10	12	11	9	7	
% Max Month	100.00%	88.63%	85.16%	77.64%	88.42%	78.53%	42.79%	31.38%	29.70%	30.24%	33.24%	49.31%	
PR	11.37%	0.10%	1.66%	4.72%	1.09%	0.18%	1.19%	0.11%	2.48%	0.05%	0.21%	0.93%	24.09%
CumPR	24.09%	12.72%	11.53%	9.69%	12.62%	9.87%	4.04%	2.64%	2.48%	2.52%	2.85%	4.97%	100.00%
Product and Pipeline Demand Costs	$ 2,160,118	$ 1,140,774	$ 1,033,685	$ 869,167	$ 1,131,391	$ 885,193	$ 362,119	$ 236,619	$ 221,993	$ 226,359	$ 255,171	$ 445,704	$ 8,968,294

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	1,453,194	1,288,023	1,237,486	1,128,257	1,284,982	1,141,241	621,751	456,059	431,653	439,435	483,114	716,558	10,681,751
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	4.7%	6.1%	6.6%	6.5%	5.8%	4.1%	1.9%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 22,437	$ 17,022	$ 14,458	$ 14,726	$ 14,767	$ 14,769	$ 18,293	$ 116,471

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Storage	-	777,812	905,414	949,914	653,281	-	-	-	-	-	-	-	3,286,419
Rank	5	3	2	1	4	5	5	5	5	5	5	5	
% Max Month	0.00%	81.88%	95.32%	100.00%	68.77%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	4.37%	6.72%	4.68%	17.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	32.96%
CumPR	0.00%	21.56%	28.28%	32.96%	17.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ -	$ 5,378,443	$ 7,053,732	$ 8,222,215	$ 4,288,464	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,942,854
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 22,437	$ 17,022	$ 14,458	$ 14,726	$ 14,767	$ 14,769	$ 18,293	$ 116,471
TOTAL	$ -	$ 5,378,443	$ 7,053,732	$ 8,222,215	$ 4,288,464	$ 22,437	$ 17,022	$ 14,458	$ 14,726	$ 14,767	$ 14,769	$ 18,293	$ 25,059,325

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	2,132	41,615	397,332	170,302	18,906	2,130	2,201	2,130	2,201	2,201	2,130	2,201	645,480
Rank	9	3	1	2	4	12	8	11	7	6	10	5	
% Max Month	0.54%	10.47%	100.00%	42.86%	4.76%	0.54%	0.55%	0.54%	0.55%	0.55%	0.54%	0.55%	
PR	0.00%	1.91%	57.14%	16.19%	1.05%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	76.34%
CumPR	0.04%	3.00%	76.34%	19.20%	1.10%	0.04%	0.05%	0.04%	0.05%	0.05%	0.04%	0.05%	100.00%
Peaking Demand Costs	$ 2,450	$ 164,439	$ 4,179,865	$ 1,051,158	$ 60,120	$ 2,446	$ 2,568	$ 2,446	$ 2,568	$ 2,568	$ 2,446	$ 2,568	$ 5,475,642

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

LN		
1		
2		`
3	Pipeline Demand	Schedule 5A, PG 1, LN 1
4	Storage Demand	Schedule 5A, PG 1, LN 3 & 4
5	Peaking Demand	Schedule 5A, PG 1, LN 3 & 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	LN 44 Ranking
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-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual
50	Pipeline & Product Demand	$ 2,160,118	$ 1,140,774	$ 1,033,685	$ 869,167	$ 1,131,391	$ 885,193	$ 362,119	$ 236,619	$ 221,993	$ 226,359	$ 255,171	$ 445,704	$ 8,968,294
51	Storage Incld Inj Fees	$ -	$ 5,378,443	$ 7,053,732	$ 8,222,215	$ 4,288,464	$ 22,437	$ 17,022	$ 14,458	$ 14,726	$ 14,767	$ 14,769	$ 18,293	$ 25,059,325
52	Peaking	$ 2,450	$ 164,439	$ 4,179,865	$ 1,051,158	$ 60,120	$ 2,446	$ 2,568	$ 2,446	$ 2,568	$ 2,568	$ 2,446	$ 2,568	$ 5,475,642
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (22,437)	$ (17,022)	$ (14,458)	$ (14,726)	$ (14,767)	$ (14,769)	$ (18,293)	$ (116,471)
54	Less: Capacity Release	$ (12,997)	$ (12,997)	$ (12,997)	$ (12,997)	$ (12,997)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (64,987)
55	Less: Asset Mgmt	$ (1,594,167)	$ (1,594,167)	$ (1,594,167)	$ (1,594,167)	$ (1,594,167)	$(1,594,167)	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,565,000)
56	Total Demand	$ 555,403	$ 5,076,492	$ 10,660,119	$ 8,535,375	$ 3,872,811	$ (706,528)	$ 364,687	$ 239,065	$ 224,561	$ 228,927	$ 257,617	$ 448,272	$ 29,756,803
57														
58	**Capacity Cost Allocator based on Design Year Firm Sendout**													
59		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual
60	**Therms**													
61	Maine	853,769	1,209,003	1,440,732	1,303,433	1,153,653	703,672	368,598	275,472	259,282	265,002	291,562	425,981	8,550,159
62	New Hampshire	601,557	898,446	1,099,499	945,039	803,515	439,699	255,354	182,717	174,572	176,634	193,682	292,778	6,063,492
63	Total	1,455,326	2,107,449	2,540,231	2,248,472	1,957,168	1,143,371	623,952	458,189	433,854	441,636	485,244	718,759	14,613,651
64	**Percentage of Total**	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual
65	Maine	58.67%	57.37%	56.72%	57.97%	58.95%	61.54%	59.07%	60.12%	59.76%	60.00%	60.09%	59.27%	57.57%
66	New Hampshire	41.33%	42.63%	43.28%	42.03%	41.05%	38.46%	40.93%	39.88%	40.24%	40.00%	39.91%	40.73%	42.43%
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	$325,828	$2,912,286	$6,046,054	$4,947,933	$2,282,829	($434,823)	$215,438	$143,730	$134,203	$137,367	$154,791	$265,674	$17,131,311
71	New Hampshire	$229,575	$2,164,206	$4,614,064	$3,587,442	$1,589,982	($271,705)	$149,249	$95,334	$90,358	$91,560	$102,826	$182,599	$12,625,491
72	Total	$ 555,403	$ 5,076,492	$ 10,660,119	$ 8,535,375	$ 3,872,811	$ (706,528)	$ 364,687	$ 239,065	$ 224,561	$ 228,927	$ 257,617	$ 448,272	$ 29,756,803

Detailed Allocation of Demand Costs by Division

73		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	
74	**Maine**	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	
75	Pipeline & Product Demand	$ 1,267,236	$ 654,440	$ 586,271	$ 503,853	$ 666,899	$ 544,780	$ 213,921	$ 142,260	$ 132,669	$ 135,826	$ 153,321	$ 264,152	$ 5,265,628	58.71%
76	Storage Incld Injection Fees	$ -	$ 3,085,509	$ 4,000,635	$ 4,766,395	$ 2,527,836	$ 13,808	$ 10,056	$ 8,692	$ 8,801	$ 8,861	$ 8,874	$ 10,842	$ 14,450,309	57.66%
77	Peaking	$ 1,437	$ 94,335	$ 2,370,676	$ 609,353	$ 35,438	$ 1,505	$ 1,517	$ 1,471	$ 1,535	$ 1,541	$ 1,470	$ 1,522	$ 3,121,800	57.01%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (13,808)	$ (10,056)	$ (8,692)	$ (8,801)	$ (8,861)	$ (8,874)	$ (10,842)	$ (69,933)	60.04%
79	Capacity Release (Credit)	$ (7,625)	$ (7,456)	$ (7,372)	$ (7,535)	$ (7,661)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (37,649)	57.93%
80	Asset Management (Credit)	$ (935,220)	$ (914,543)	$ (904,157)	$ (924,134)	$ (939,682)	$ (981,108)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,598,843)	58.53%
81	**Total Allocated Demand**	$ 325,828	$ 2,912,286	$ 6,046,054	$ 4,947,933	$ 2,282,829	$ (434,823)	$ 215,438	$ 143,730	$ 134,203	$ 137,367	$ 154,791	$ 265,674	$ 17,131,311	57.57%
82															
83	**New Hampshire**	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	
84	Pipeline & Product Demand	$ 892,882	$ 486,334	$ 447,414	$ 365,313	$ 464,493	$ 340,413	$ 148,198	$ 94,359	$ 89,325	$ 90,533	$ 101,850	$ 181,552	$ 3,702,666	41.29%
85	Storage Incld Injection Fees	$ -	$ 2,292,933	$ 3,053,097	$ 3,455,820	$ 1,760,628	$ 8,628	$ 6,966	$ 5,765	$ 5,925	$ 5,906	$ 5,895	$ 7,451	$ 10,609,016	42.34%
86	Peaking	$ 1,013	$ 70,103	$ 1,809,189	$ 441,804	$ 24,682	$ 941	$ 1,051	$ 975	$ 1,033	$ 1,027	$ 976	$ 1,046	$ 2,353,841	42.99%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (8,628)	$ (6,966)	$ (5,765)	$ (5,925)	$ (5,906)	$ (5,895)	$ (7,451)	$ (46,538)	
88	Capacity Release	$ (5,372)	$ (5,541)	$ (5,626)	$ (5,463)	$ (5,336)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (27,338)	42.07%
89	Asset Management	$ (658,947)	$ (679,624)	$ (690,010)	$ (670,033)	$ (654,485)	$ (613,059)	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,966,157)	41.47%
90	**Total Allocated Demand**	$ 229,575	$ 2,164,206	$ 4,614,064	$ 3,587,442	$ 1,589,982	$ (271,705)	$ 149,249	$ 95,334	$ 90,358	$ 91,560	$ 102,826	$ 182,599	$ 12,625,491	42.43%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
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-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	Summer
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	521,843	331,246	299,589	302,138	347,502	673,103	8,817,574	2,475,421
3	Total Storage	0	0	0	0	0	0	1,741,407	0
4	Total Peaking	2,201	2,130	2,201	2,201	2,130	2,201	274,648	13,064
5	Total Off-system Sales							0	
6	Subtotal	524,044	333,376	301,790	304,339	349,632	675,304	10,833,629	2,488,485
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	524,044	333,376	301,790	304,339	349,632	675,304	10,833,629	2,488,485
10	Total Firm Pipeline Sendout	521,843	331,246	299,589	302,138	347,502	673,103	8,817,574	2,475,421
11	**Variable Costs**								
12	Pipeline Costs Modeled in Sendout™	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 42,575,963	$ 5,064,105
13	NYMEX Price Used for Forecast	$1.787	$1.900	$1.996	$2.046	$2.065	$2.107		
14	NYMEX Price Used for Update	$1.787	$1.900	$1.996	$2.046	$2.065	$2.107		
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	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 40,233,457	$ 5,064,105
18									
19	Total Pipeline	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 40,233,457	$ 5,064,105
20	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,449,700	$ -
21	Total Peaking	$ 20,534	$ 19,907	$ 20,638	$ 20,675	$ 20,119	$ 20,863	$ 2,442,951	$ 122,736
22	Total Off-sytem Sales							$ -	
23									
24	Subtotal	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 48,126,108	$ 5,186,841
25									
26	Hedging Expense & (Gain)/Loss Estimate								
27	NYMEX Options Contracts								
28	Number of contracts	-	-	-	-	-	-	195	-
29	Option Contract Price								
30	Hedging Expense							$ 207,790	
31	NYMEX Option Strike Price	$ -	$ -	$ -	$ -	$ -	$ -		
32	NYMEX Price Used for Forecast	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107		
33	NYMEX Price Used for Update	$ 1.787	$ 1.900	$ 1.996	$ 2.046	$ 2.065	$ 2.107		
34	Option Hedging Gain (Credit)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Option Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 207,790	$ -
36									
37	Interruptible Cost Estimate								
38	Variable Pipeline Costs Excld Hedges	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 40,233,457	$ 5,064,105
39	Average Supply Cost ($/MMBtu)	$ 1.867	$ 1.851	$ 1.897	$ 1.951	$ 2.035	$ 2.394		
40	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42									
43	Firm Sales Pipeline Commodity Excld Hedge	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 40,233,457	$ 5,064,105
44	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,449,700	$ -
45	Total Peaking	$ 20,534	$ 19,907	$ 20,638	$ 20,675	$ 20,119	$ 20,863	$ 2,442,951	$ 122,736
46	Off-system Sales							$ -	
47	Firm Sales Variable Costs Excld Hedge	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 48,126,108	$ 5,186,841
48	Plus Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	$ 207,790	$ -
49	Total Firm Sales Variable Costs	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 48,333,898	$ 5,186,841

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 21
14	NYMEX Price Used for Update	Attachment to Schedule 5A, PG 1, LN 21
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	Schedule 7
31	NYMEX Option Strike Price	Schedule 7
32	NYMEX Price Used for Forecast	Line 13
33	NYMEX Price Used for Update	Line 14
34	Option Hedging Gain (Credit)	LN 33 - LN 32 * LN28 * 10,000
35	Total Option Cost	(LN 31 - LN 32 - 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

Line		May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual	Summer
50	**Commodity Allocation Factors**								
51	Firm Sales Sendout for Normal Winter, MMBtu								
52		**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
53	Maine	318,138	196,215	177,209	174,833	207,858	409,909	6,466,209	1,484,162
54	New Hampshire	205,906	137,161	124,581	129,506	141,774	265,395	4,367,420	1,004,323
55	Total	524,044	333,376	301,790	304,339	349,632	675,304	10,833,629	2,488,485
56									
57	**Percentage of Total**								
58	Maine	60.71%	58.86%	58.72%	57.45%	59.45%	60.70%	59.69%	59.64%
59	New Hampshire	39.29%	41.14%	41.28%	42.55%	40.55%	39.30%	40.31%	40.36%
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	$ 591,609	$ 360,917	$ 333,685	$ 338,595	$ 420,429	$ 978,187	$ 24,002,759	$ 3,023,423
65	Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,797	$ -
66	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,247,486	$ -
67	Peaking	$ 12,466	$ 11,717	$ 12,118	$ 11,877	$ 11,961	$ 12,664	$ 1,460,601	$ 72,803
68	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	Total Maine Commodity Costs	$ 604,075	$ 372,633	$ 345,804	$ 350,472	$ 432,389	$ 990,851	$ 28,834,644	$ 3,096,225
70	Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,599	$ -
71	Total Maine Variable Costs	$ 604,075	$ 372,633	$ 345,804	$ 350,472	$ 432,389	$ 990,851	$ 28,838,242	$ 3,096,225
72	**New Hampshire**								
73	Firm Sales Pipeline Commodity Excld Hedge	$ 382,903	$ 252,293	$ 234,587	$ 250,812	$ 286,762	$ 633,326	$ 16,230,697	$ 2,040,682
74	Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	`	$ -
75	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,202,214	$ -
76	Peaking	$ 8,068	$ 8,190	$ 8,519	$ 8,798	$ 8,158	$ 8,199	$ 982,350	$ 49,933
77	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Total New Hampshire Commodity Costs	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,499,254	$ 2,090,615
79	New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,487	$ -
80	Total New Hampshire Variable Costs	$ 390,971	$ 260,483	$ 243,106	$ 259,609	$ 294,920	$ 641,525	$ 19,501,741	$ 2,090,615
81	**Northern Utilities**								
82	Firm Sales Pipeline Commodity Excld Hedge	$ 974,512	$ 613,210	$ 568,272	$ 589,407	$ 707,191	$ 1,611,513	$ 40,233,457	$ 5,064,105
83	Net Hedging Expense / (Gain)	$ -	$ -	$ -	$ -	$ -	$ -	$ 207,790	$ -
84	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,449,700	$ -
85	Peaking	$ 20,534	$ 19,907	$ 20,638	$ 20,675	$ 20,119	$ 20,863	$ 2,442,951	$ 122,736
86	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	Total Northern Commodity Costs	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 48,333,898	$ 5,186,841
88	Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,085	$ -
89	Total Northern Variable Costs	$ 995,046	$ 633,117	$ 588,910	$ 610,082	$ 727,310	$ 1,632,377	$ 48,339,983	$ 5,186,841
90									

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

LN		
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

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

Col A	Col H	Col I	Col J	Col K	Col L	Col M	Col N	Col P
Inventory Finance Charge	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Annual**	**Summer**
Storage	$ 186	$ 262	$ 339	$ 417	$ 488	$ 559	$ 4,472	$ 2,251
Peaking	$ 201	$ 198	$ 196	$ 185	$ 183	$ 191	$ 2,252	$ 1,153
Total	$ 387	$ 459	$ 535	$ 601	$ 672	$ 750	$ 6,724	$ 3,405
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 235	$ 270	$ 314	$ 346	$ 399	$ 456	$ 4,000	$ 2,020
New Hampshire	$ 152	$ 189	$ 221	$ 256	$ 272	$ 295	$ 2,724	$ 1,385
Total	$ 387	$ 459	$ 535	$ 601	$ 672	$ 750	$ 6,724	$ 3,405
Inventory Finance Charge Allocation by Month								
Maine								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	4,391,645	0
Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	89.97%	0.00%
ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,599	$ -
New Hampshire								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,897,943	0
Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	91.28%	0.00%
NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,487	$ -

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**

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LN	Description	Calculation	
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 - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Average Cost of Gas Calculation

		Winter	Summer	Annual	
1	Demand	$ 7,597,581	$ 933,408	$ 8,530,989	Schedule 1A, LN 81
2	Commodity	$ 17,411,125	$ 2,090,615	$ 19,501,741	Schedule 1B, LN 43
3	Total	$ 25,008,706	$ 3,024,024	$ 28,032,730	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	33,294,125	9,940,234	43,234,360	Schedule 10B, LN 11
6	Forecasted Residential Sales (Therms)	14,977,297	3,470,624	18,447,921	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Annual**	
8	Average Demand Rate	$0.2282	$0.0939		LN 1 / LN 5
9	Average Commodity Rate	$0.5229	$0.2103		LN 2 / LN 5
10	Average Rate	$0.7511	$0.3042		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Annual**	
13	Demand Costs Allocated To Residential per SMBA	$ 4,798,384	$ 406,829	$ 5,205,213	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 3,417,757	$ 325,892	$ 3,743,648	LN 8 * LN 6
15	**Demand Reallocation:**	$ 1,380,628	$ 80,937	$ 1,461,565	LN 13 - LN 14
16	**HLF Allocation**	$ 167,302	$ 26,630	$ 193,933	LN 15 * LN 20
17	**LLF Allocation**	$ 1,213,325	$ 54,307	$ 1,267,632	LN 15 * LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	12.12%	32.90%		Schedule 10A, LN 173
21	LLF	87.88%	67.10%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 7,790,234	$ 729,937	$ 8,520,171	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 7,832,361	$ 729,872	$ 8,562,233	LN 9 * LN 6
25	**Commodity Reallocation:**	$ (42,127)	$ 64	$ (42,062)	LN 23 - LN 24
26	**HLF Allocation**	$ (7,885)	$ 35	$ (7,850)	LN 25 * LN 30
27	**LLF Allocation**	$ (34,242)	$ 30	$ (34,212)	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	18.72%	53.75%		Schedule 10C, LN 143
31	LLF	81.28%	46.25%		Schedule 10C, LN 144

Schedule 24

Provided in Winter 2015-16 Cost-of-Gas Filing

Schedule 25

Northern Utilities - New Hampshire Division
PNGTS Refund - Year 2

	Total Refund A	Estimated Remaining Refund Balance* B	Year 2 Refund** C = B * 60%	Estimated Marketer Portion*** D = C * .2	Estimated Sales Portion E = C - D	Summer Allocation F	Year 2 Summer Refund G = E * F
Winter Contract	$ 10,060,892.88	$ 4,202,504.47	$ 2,521,502.68	$ 504,300.54	$ 2,017,202.14	4.57%	$ 92,158.91
Annual Contract	$ 359,416.47	$ 150,130.74	$ 90,078.45	$ 18,015.69	$ 72,062.76	50.00%	$ 36,031.38
Total	$ 10,420,309.36	$ 4,352,635.21	$ 2,611,581.13	$ 522,316.23	$ 2,089,264.90		$ 128,190.29

* Reflects estimated refunds to marketers
** Reflects estimated refunds to marketers
** Reflects 20% allocation to total annual refund to marketers