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	$ 3,371,527
3	Storage	$ 15,634,031
4	Peaking	$ 866,963
5	Total Gross Demand Cost	$ 19,872,521
6		
7	Capacity Assignment Demand Revenue Estimate	$ 3,420,191
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,872,521
9	Capacity Assignment as % of Total Gross Demand Cost	17.21%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 580,262
14	Storage	$ 2,690,719
15	Peaking	$ 149,210
16	Total Capacity Assignment Credit	$ 3,420,191
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,791,265
21	Storage	$ 12,943,312
22	Peaking	$ 717,753
23	Total Net Demand Cost (Less Capacity Assignment)	$ 16,452,330
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	13,681
28	Less 17.21% NH Transp. Capacity Assignment	(2,355)
29	Net Pipeline MDQ	11,326
30		
31	Net Pipeline MDQ	11,326
32	Less: Firm Sales Base Use	3,475
33	Remaining Pipeline MDQ	7,852
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$246.44
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,791,265
40	Less: Base Pipeline Use	$ 856,305
41	Remaining Pipeline Use	$ 1,934,960

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	Attachment NUI-FXW-5
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	ıt Costs
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 17.21% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR
(Based on NH Firm Sales Sendout for Remaining Temperature Sensit

All Months	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
Remaining Load for All Months	282,705	51,802	0	9,295	134,982	677,765	23,718,727	22,562,178	1,156,549
Rank	8	10	12	11	9	7			
% Max Month	5.48%	1.00%	0.00%	0.18%	2.62%	13.15%			
PR	0.36%	0.08%	0.00%	0.02%	0.18%	1.09%	32.09%		
CumPR	0.64%	0.10%	0.00%	0.02%	0.28%	1.73%	100.00%	97.24%	2.76%

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

DEMAND COST PR ALLOCATORS

	May	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
Pipeline - Remaining	0.64%	0.10%	0.00%	0.02%	0.28%	1.73%	100.00%	97.24%	2.76%
Storage & Peaking	0.64%	0.10%	0.00%	0.02%	0.28%	1.73%	100.00%	97.24%	2.76%
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**	**Total**	**Winter**	**Summer**	**Summer**
Pipeline - Base	$ 71,359	$ 71,359	$ 71,359	$ 71,359	$ 71,359	$ 71,359	$ 856,305	$ 428,153	$ 428,153	50.00%
Pipeline - Remaining	$ 12,313	$ 1,913	$ -	$ 317	$ 5,382	$ 33,497	$ 1,934,960	$ 1,881,538	$ 53,421	2.76%
Total Pipeline	$ 83,672	$ 73,271	$ 71,359	$ 71,676	$ 76,741	$ 104,856	$ 2,791,265	$ 2,309,691	$ 481,574	17.25%
Storage & Peaking	$ 86,930	$ 13,504	$ -	$ 2,239	$ 37,996	$ 236,492	$ 13,661,065	$ 13,283,903	$ 377,162	2.76%
Less Credits to Demand Cost										
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$2,405,780	$ 2,405,780	$ -	0.00%
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Direct Demand Costs	$ 170,602	$ 86,775	$ 71,359	$ 73,915	$ 114,737	$ 341,348	$ 14,046,550	$ 13,187,814	$ 858,736	6.11%

	Total	**Winter**	**Summer**	**Summer**
Indirect Demand Costs/(Credits)				
Miscellaneous Overhead	$ 411,600	$ 326,424	$ 85,176	20.69%
Local Production & Storage	$ 307,762	$ 307,762	$ -	0.00%
Subtotal	$ 719,362	$ 634,186	$ 85,176	11.84%

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

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**	
43	(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)	
44		
45	**All Months**	
46	Remaining Load for All Months	Schedule 10B, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49
51		
52	**Peak Months Only**	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56
58		
59	**DEMAND COST PR ALLOCATORS**	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57
66		
67	**DEMAND COSTS ALLOCATED TO MONTHS**	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	LN 64 * Sum (Schedule 21 LN 88, Schedule 21 LN 89)
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	1,352,617	1,087,250	1,060,564	1,079,060	1,170,198	1,747,568	23,024,066	7,497,257
2	New Hampshire Sales Storage	0	0	0	0	0	0	13,296,167	0
3	New Hampshire Sales Peaking	7,231	6,948	7,284	7,378	7,181	7,340	106,440	43,362
4	Total New Hampshire Firm Sales Sendout	1,359,848	1,094,199	1,067,848	1,086,438	1,177,378	1,754,908	36,426,674	7,540,619
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	1,359,848	1,094,199	1,067,848	1,086,438	1,177,378	1,754,908	36,426,674	7,540,619
9	Total Firm Sales	1,346,492	1,083,360	1,057,284	1,075,722	1,165,799	1,737,916	36,081,030	7,466,573
10	Difference (LAUF & Company Use)	13,356	10,838	10,564	10,716	11,580	16,992	345,643	74,047
11	Percent Difference	0.98%	0.99%	0.99%	0.99%	0.98%	0.97%	0.95%	0.98%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 239,172	$ 206,999	$ 211,539	$ 220,144	$ 241,654	$ 375,730	$ 10,481,952	$ 1,495,238
15	New Hampshire Hedging (Gains) Losses	$ 80,243	$ -	$ -	$ -	$ -	$ 91,339	$ 419,138	$ 171,582
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,021,299	$ -
17	New Hampshire Total Peaking	$ 3,869	$ 3,619	$ 3,707	$ 3,680	$ 3,521	$ 3,548	$ 63,797	$ 21,944
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,048	$ -
19	Total New Hampshire Sales Variable Costs	$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 16,992,234	$ 1,688,765
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 243,041	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 379,278	$ 16,573,096	$ 1,517,183
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 16,992,234	$ 1,688,765
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.1768	$ 0.1904	$ 0.1995	$ 0.2040	$ 0.2065	$ 0.2150	$ 0.4553	$ 0.1994
27	New Hampshire Hedging (Gains) Losses	$ 0.0593	$ -	$ -	$ -	$ -	$ 0.0523	$ 0.0182	$ 0.0229
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.4529	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.5351	$ 0.5208	$ 0.5089	$ 0.4988	$ 0.4904	$ 0.4834	$ 0.5994	$ 0.5061
30	New Hampshire Inventory Finance Costs per Dth Stor and F	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0005	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.2377	$ 0.1925	$ 0.2016	$ 0.2060	$ 0.2082	$ 0.2682	$ 0.4665	$ 0.2240
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	1,077,155	1,042,408	1,067,860	1,077,155	1,042,408	1,077,155	12,708,083	6,384,141
37	Base Commodity Cost Excld Hedging	$ 190,464	$ 198,461	$ 212,995	$ 219,756	$ 215,264	$ 231,590	$ 4,987,902	$ 1,268,531
38	Base Hedging Commodity Cost	$ 63,902	$ -	$ -	$ -	$ -	$ 56,299	$ 241,940	$ 120,200
39	Remaining Commodity Excld Hedging	$ 52,577	$ 12,156	$ 2,252	$ 4,069	$ 29,911	$ 147,688	$ 11,585,194	$ 248,652
40	Remaining Hedging Commodity	$ 16,342	$ -	$ -	$ -	$ -	$ 35,040	$ 177,198	$ 51,382
41	Total Commodity Excld Hedging	$ 243,041	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 379,278	$ 16,573,096	$ 1,517,183
42	Total Hedging	$ 80,243	$ -	$ -	$ -	$ -	$ 91,339	$ 419,138	$ 171,582
43	Total Commodity (Incl Hedging)	$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 16,992,234	$ 1,688,765

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

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

Schedule 2

Estimated Delivered City-Gate Commodity Costs and Volumes May 2012 through October 2012			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	$1,413,197	446,542	$3.165
PNGTS	$593,424	183,356	$3.236
Lewiston Baseload	$1,491,108	460,000	$3.242
Tennessee Production	$1,118,192	341,568	$3.274
LNG	$41,917	8,280	$5.062
Total System	$4,657,839	1,439,746	$3.235

Schedules 3A &3B

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

			Winter						Summer						
	Sales Revenues								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Oct-10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total
2	Residential Heat & Non Heat								620,349	498,705	486,807	495,340	537,038	801,781	3,440,019
3	Sales HLF Classes								317,576	256,202	249,862	254,146	275,062	408,075	1,760,923
4	Sales LLF Classes								408,568	328,452	320,616	326,236	353,698	528,061	2,265,631
5	Total								1,346,492	1,083,360	1,057,284	1,075,722	1,165,799	1,737,916	7,466,573
6	Rates														
7	Residential Heat & Non Heat CGA								$0.3371	$0.3371	$0.3371	$0.3371	$0.3371	$0.3371	
8	Sales HLF Classes CGA								$0.2942	$0.2942	$0.2942	$0.2942	$0.2942	$0.2942	
9	Sales LLF Classes CGA								$0.3704	$0.3704	$0.3704	$0.3704	$0.3704	$0.3704	
10	Revenues														
11	Residential Heat & Non Heat								$ (209,119)	$ (168,114)	$ (164,102)	$ (166,979)	$ (181,035)	$ (270,280)	$ (1,159,630)
12	Sales HLF Classes								$ (93,431)	$ (75,375)	$ (73,509)	$ (74,770)	$ (80,923)	$ (120,056)	$ (518,064)
13	Sales LLF Classes								$ (151,334)	$ (121,659)	$ (118,756)	$ (120,838)	$ (131,010)	$ (195,594)	$ (839,190)
14	Total Sales								$ (453,884)	$ (365,147)	$ (356,368)	$ (362,587)	$ (392,969)	$ (585,930)	$ (2,516,884)
15															

			Winter						Summer						
16															
17	**Gas Costs and Credits**								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18		Oct-10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 80,262	$ 80,262	$ 80,262	$ 80,262	$ 80,262	$ 80,262	$ 481,574
21	Storage								$ 59,439	$ 59,439	$ 59,439	$ 59,439	$ 59,439	$ 59,439	$ 356,632
22	Peaking								$ 3,422	$ 3,422	$ 3,422	$ 3,422	$ 3,422	$ 3,422	$ 20,529
24	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 143,123	$ 143,123	$ 143,123	$ 143,123	$ 143,123	$ 143,123	$ 858,736
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								260,938	211,239	203,111	204,032	220,001	332,146	1,431,466
27	Pipeline Costs Modeled in Sendout™								$ 801,396	$ 666,854	$ 654,543	$ 664,562	$ 719,858	$ 1,108,708	$ 4,615,921
28	NYMEX Price Used for Forecast								$ 4.0150	$ 4.0550	$ 4.0980	$ 4.1210	$ 4.1210	$ 4.1550	
29	NYMEX Price Used for Update								$ 2.7120	$ 2.8020	$ 2.8700	$ 2.9040	$ 2.9140	$ 2.9670	
30	Increase/(Decrease) NYMEX Price								$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	
31	Increase/(Decrease) in Pipeline Costs								$ (340,002)	$ (264,682)	$ (249,420)	$ (248,307)	$ (265,541)	$ (394,589)	
32	Updated Pipeline Costs								$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 1.77	$ 1.90	$ 1.99	$ 2.04	$ 2.07	$ 2.15	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	
37	New Hampshire Allocated Percentage								51.84%	51.47%	52.22%	52.89%	53.19%	52.61%	
38	NH Updated Pipeline Costs								$ 239,172	$ 206,999	$ 211,539	$ 220,144	$ 241,654	$ 375,730	$ 1,495,238
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								12	0	0	0	0	14	
42	Average Purchase Price								$ 4.0020	$ -	$ -	$ -	$ -	$ 4.2070	
43	NYMEX Price Used for Forecast								$ 4.0150	$ 4.0550	$ 4.0980	$ 4.1210	$ 4.1210	$ 4.1550	
44	NYMEX Price Used for Update								$ 2.7120	$ 2.8020	$ 2.8700	$ 2.9040	$ 2.9140	$ 2.9670	
45	Increase/(Decrease) NYMEX Price								(1.3030)	(1.2530)	(1.2280)	(1.2170)	(1.2070)	(1.1880)	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ 154,800	$ -	$ -	$ -	$ -	$ 173,600	$ 328,400
47	New Hampshire Allocated Percentage								51.84%	51.47%	52.22%	52.89%	53.19%	52.61%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 80,243	$ -	$ -	$ -	$ -	$ 91,339	$ 171,582
49	Price Triggered NYMEX Contracts (NH Only)														
50	NYMEX NG Futures Contracts								0	0	0	0	0	0	
51	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
52	NYMEX Price Used for Forecast								$ 4.0150	$ 4.0550	$ 4.0980	$ 4.1210	$ 4.1210	$ 4.1550	
53	NYMEX Price Used for Update								$ 2.7120	$ 2.8020	$ 2.8700	$ 2.9040	$ 2.9140	$ 2.9670	
54	Increase/(Decrease) NYMEX Price								(1.3030)	(1.2530)	(1.2280)	(1.2170)	(1.2070)	(1.1880)	
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								$ 239,172	$ 206,999	$ 211,539	$ 220,144	$ 241,654	$ 375,730	$ 1,495,238
60	Hedging (Gain)/Loss Estimate								$ 80,243	$ -	$ -	$ -	$ -	$ 91,339	$ 171,582
61	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Peaking								$ 3,869	$ 3,619	$ 3,707	$ 3,680	$ 3,521	$ 3,548	$ 21,944
63	Total Commodity Costs								$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 1,688,765

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**		$ -	$ -	$ -	$ -	$ -	$ -	$ 466,407	$ 353,740	$ 358,369	$ 366,947	$ 388,298	$ 613,740	$ 2,547,501
75			Winter						Summer						
76							(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Oct-10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 466,407	$ 353,740	$ 358,369	$ 366,947	$ 388,298	$ 613,740	$ 2,547,501
80	Working Capital Percentage		0.0824%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
81	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -	$ -	$ 384	$ 291	$ 295	$ 302	$ 320	$ 505	$ 2,098
82	Beginning Period Working Capital Balance		$ (978)	$ (980)	$ (982)	$ (983)	$ (985)	$ (987)	$ (989)	$ (606)	$ (316)	$ (21)	$ 282	$ 602	
83	End of Period Working Capital Allowance		$ (978)	$ (980)	$ (982)	$ (983)	$ (985)	$ (987)	$ (605)	$ (315)	$ (20)	$ 282	$ 602	$ 1,108	
84	Interest		$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (1)	$ (1)	$ (0)	$ 0	$ 1	$ 2	$ (11)
85	End of period with Interest	$ (978)	$ (980)	$ (982)	$ (983)	$ (985)	$ (987)	$ (989)	$ (606)	$ (316)	$ (21)	$ 282	$ 602	$ 1,109	
86	Bad Debt														
92	Projected Bad Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	Beginning Period Bad Debt Balance		$ (1,497)	$ (1,500)	$ (1,502)	$ (1,505)	$ (1,508)	$ (1,511)	$ (1,513)	$ (1,516)	$ (1,519)	$ (1,522)	$ (1,524)	$ (1,527)	
94	End of Period Bad Debt Balance		***$ (1,497)***	***$ (1,500)***	***$ (1,502)***	***$ (1,505)***	***$ (1,508)***	***$ (1,511)***	***$ (1,513)***	***$ (1,516)***	***$ (1,519)***	***$ (1,522)***	***$ (1,524)***	***$ (1,527)***	
95	Interest		$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (33)
96	End of Period Bad Debt Balance with Interest	$ (1,497)	$ (1,500)	$ (1,502)	$ (1,505)	$ (1,508)	$ (1,511)	$ (1,513)	$ (1,516)	$ (1,519)	$ (1,522)	$ (1,524)	$ (1,527)	$ (1,530)	
97	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	Miscellaneous Overhead								$ 14,196	$ 14,196	$ 14,196	$ 14,196	$ 14,196	$ 14,196	$ 85,176
100	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
101	Beginning Balance Over/Under Collection		$ (151,792)	$ (153,254)	$ (154,191)	$ (154,439)	$ (154,720)	$ (155,002)	$ (155,285)	$ (128,824)	$ (126,267)	$ (110,285)	$ (91,913)	$ (82,547)	$ (1,618,518)
102	Net Costs - Revenues		$ (1,184)	$ (658)	$ 33	$ -	$ -	$ -	$ 26,719	$ 2,789	$ 16,197	$ 18,556	$ 9,525	$ 42,006	$ 113,984
103	Ending Balance before Interest		$ (152,976)	$ (153,911)	$ (154,158)	$ (154,439)	$ (154,720)	$ (155,002)	$ (128,565)	$ (126,035)	$ (110,070)	$ (91,729)	$ (82,388)	$ (40,540)	$ (1,504,534)
104	Average Balance		$ (152,384)	$ (153,583)	$ (154,175)	$ (154,439)	$ (154,720)	$ (155,002)	$ (141,925)	$ (127,429)	$ (118,168)	$ (101,007)	$ (87,150)	$ (61,543)	$ (1,561,526)
105	Interest Rate		2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
106	Interest Expense		$ (278)	$ (280)	$ (281)	$ (281)	$ (282)	$ (282)	$ (259)	$ (232)	$ (215)	$ (184)	$ (159)	$ (112)	$ (2,845)
108	Ending Balance Incl Interest Expense	$ (151,792)	$ (153,254)	$ (154,191)	$ (154,439)	$ (154,720)	$ (155,002)	$ (155,285)	$ (128,824)	$ (126,267)	$ (110,285)	$ (91,913)	$ (82,547)	$ (40,652)	
109	**Total Over/Under Collection Ending Balance**	$ (154,267)	$ (155,733)	$ (156,675)	$ (156,927)	$ (157,213)	$ (157,500)	$ (157,787)	$ (130,946)	$ (128,101)	$ (111,828)	$ (93,156)	$ (83,471)	$ (41,073)	
110														
111	**Total Indirect Cost of Gas**	$ (154,267)	$ (282)	$ (284)	$ (285)	$ (286)	$ (286)	$ (287)	$ 14,317	$ 14,252	$ 14,273	$ 14,312	$ 14,355	$ 14,588	$ (69,881)
112														
113	**Total Cost of Gas**	$ (154,267)	$ (282)	$ (284)	$ (285)	$ (286)	$ (286)	$ (287)	$ 480,724	$ 367,992	$ 372,642	$ 381,259	$ 402,653	$ 628,328	$ 2,477,619
114														
115	**Total Interest**	$ -	$ (282)	$ (284)	$ (285)	$ (286)	$ (286)	$ (287)	$ (263)	$ (236)	$ (218)	$ (187)	$ (161)	$ (113)	$ (2,889)

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2011**			
2				
3	Total	$	597,172	
4	Distribution	$	214,499	
5	Non-Distribution	$	382,673	
6	Non-Distribution(%)		64.08%	LN 5 / LN 3
7				
8	Non-Distribution	$	382,673	
9	Peak Period	$	346,780	
10	Off-Peak Period	$	35,893	
11	Off-Peak Period (%)		9.38%	LN 9 / LN 8
12				
13	**Forecast Bad Debt Expense 12 Months Ended December 31, 2012**			
14				
15	Annual Total	$	650,000	Company Forecast
16	Annual Non-Distribution	$	416,526	LN 15* LN 6
17	Off-Peak Non-Distribution	**$**	**39,068**	LN 16 * LN 11

Schedules 4

Reserved for Future Use

Schedules 5A & Attachments, 5B and 5C

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2011 through October 31, 2012			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,686,038	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 28,451,423	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,303,860	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 508,750	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (4,400,490)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs - Updated Forecast	$ 37,586,427	Sum Lines 1 through 6.
8.	Total Demand Costs - Previous Forecast	$ 39,468,889	Winter COG Filing (Schedule 5A)
9.	Net Change in Forecast	$ (1,882,461)	Line 8 minus Line 7.

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

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ (Dth)	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Months Per Year	Support for Demand Rate	Monthly Demand	Annual Demand
Algonquin	93002F	AFT-1 (AFT-2)	No	4,211	Mendon, MA	Brockton, MA	$ 6.1138	12	Line 1 of Page 2, Att to Sch 5A	$ 25,745	$ 308,943
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	1,251	Centerville, NJ	Taunton, MA	$ 5.9771	12	Line 2 of Page 2, Att to Sch 5A	$ 7,477	$ 89,728
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.1000	12	Line 3 of Page 2, Att to Sch 5A	$ 310,000	$ 3,720,000
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	Line 4 of Page 2, Att to Sch 5A	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 40.2456	12	Line 5 of Page 2, Att to Sch 5A	$ 44,270	$ 531,242
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 76.4666	5	Line 6 of Page 2, Att to Sch 5A	$ 2,523,398	$ 12,616,989
Tennessee	5083	FT-A	No	4,605	Zone 0	Zone 6	$ 24.4547	12	Line 7 of Page 2, Att to Sch 5A	$ 112,614	$ 1,351,367
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 21.6916	12	Line 8 of Page 2, Att to Sch 5A	$ 185,463	$ 2,225,558
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 8.4896	12	Line 9 of Page 2, Att to Sch 5A	$ 22,523	$ 270,275
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 10,460	$ 125,521
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 16,561	$ 198,727
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 6,911	$ 82,937
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sch 5A	$ 31,745	$ 380,937
Tennessee	46314	FT-A	No	950	Zone 5	Zone 6	$ 7.4396	5	Line 10 of Page 2, Att to Sch 5A	$ 7,068	$ 35,338
Texas Eastern	800464	CDS	No	33	ELA	M1	$ 2.3701	12	Line 11 of Page 2, Att to Sch 5A	$ 78	$ 939
Texas Eastern	800464	CDS	No	9	ETX	M1	$ 2.1665	12	Line 12 of Page 2, Att to Sch 5A	$ 19	$ 234
Texas Eastern	800464	CDS	No	16	STX	M1	$ 6.7878	12	Line 13 of Page 2, Att to Sch 5A	$ 109	$ 1,303
Texas Eastern	800464	CDS	No	18	WLA	M1	$ 2.8175	12	Line 14 of Page 2, Att to Sch 5A	$ 51	$ 609
Texas Eastern	800464	CDS	No	59	M1	M3	$ 10.9950	12	Line 15 of Page 2, Att to Sch 5A	$ 649	$ 7,784
Texas Eastern	800436	CDS	No	64	M3	M3	$ 5.2810	12	Line 16 of Page 2, Att to Sch 5A	$ 338	$ 4,056
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.7180	12	Line 17 of Page 2, Att to Sch 5A	$ 5,518	$ 66,214
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 30.0972	2	Line 18 of Page 2, Att to Sch 5A	$ 1,023,305	$ 2,046,610
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 30.0972	10	Line 18 of Page 2, Att to Sch 5A	$ 1,023,305	$ 10,233,048
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 12.3344	2	Line 19 of Page 2, Att to Sch 5A	$ 73,229	$ 146,459
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 12.3344	10	Line 19 of Page 2, Att to Sch 5A	$ 73,229	$ 732,293
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.5670	12	Line 20 of Page 2, Att to Sch 5A	$ 15,410	$ 184,916
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 21 of Page 2, Att to Sch 5A	$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	W-10	Dawn	$ 4.5625	5	Line 22 of Page 2, Att to Sch 5A	$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Alliance	St. Clair	$ 7.7745	12	Line 23 of Page 2, Att to Sch 5A	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.4975	12	Line 24 of Page 2, Att to Sch 5A	$ 3,020	$ 36,238

Total Annual Demand Costs $ 38,441,321

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

Pipeline	Contract ID	MDQ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93002F	4,211	4,211			100%	0%	0%	$ 308,943	$ 308,943	$ -	$ -
Algonquin	93201A1C	1,251	1,166	85		93%	7%	0%	$ 89,728	$ 83,632	$ 6,097	$ -
Granite	10-010-FT-NN	100,000	29,421	35,529	35,050	29%	36%	35%	$ 3,720,000	$ 1,094,461	$ 1,321,679	$ 1,303,860
Iroquois	R181001	6,569	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	1,100			100%	0%	0%	$ 531,242	$ 531,242	$ -	$ -
PNGTS	1997-004	33,000		33,000		0%	100%	0%	$ 12,616,989	$ -	$ 12,616,989	$ -
Tennessee	5083	4,605	4,605			100%	0%	0%	$ 1,351,367	$ 1,351,367	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,225,558	$ 2,225,558	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 270,275	$ -	$ 270,275	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 125,521	$ 125,521	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 198,727	$ 198,727	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 82,937	$ 82,937	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 380,937	$ 380,937	$ -	$ -
Tennessee	46314	950	950	-		100%	0%	0%	$ 35,338	$ 35,338	$ -	$ -
Texas Eastern	800464	33	33			100%	0%	0%	$ 939	$ 939	$ -	$ -
Texas Eastern	800464	9	9			100%	0%	0%	$ 234	$ 234	$ -	$ -
Texas Eastern	800464	16	16			100%	0%	0%	$ 1,303	$ 1,303	$ -	$ -
Texas Eastern	800464	18	18			100%	0%	0%	$ 609	$ 609	$ -	$ -
Texas Eastern	800464	59	59			100%	0%	0%	$ 7,784	$ 7,784	$ -	$ -
Texas Eastern	800436	64	64	-		100%	0%	0%	$ 4,056	$ 4,056	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 66,214	$ 66,214	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 2,046,610	$ -	$ 2,046,610	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 10,233,048	$ -	$ 10,233,048	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 146,459	$ 146,459	$ -	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 732,293	$ 732,293	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 184,916	$ 184,916	$ -	$ -
Vector	CRL-NUI-0725	17,172		17,172		0%	100%	0%	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	6,070	-		100%	0%	0%	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,070	6,070	-		100%	0%	0%	$ 36,238	$ 36,238	$ -	$ -
Annual Total Demand Costs									$ 38,441,321	$ 8,686,038	$ 28,451,423	$ 1,303,860

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

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

Total Annual Fixed Charges $ 3,036,846

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2011 through October 31, 2012

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

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2011 through October 31, 2012

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

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

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

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for February 27, 2012

Estimated Adders to NYMEX Last Day Settlement

Line		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
1	CHICAGO	$0.063	$0.063	$0.063	$0.063	$0.063	$0.063
2	PNGTS	$0.360	$0.360	$0.360	$0.360	$0.360	$0.360
3	LEWISTON	$0.380	$0.380	$0.380	$0.380	$0.380	$0.380
4	NIAGARA	$0.357	$0.357	$0.357	$0.357	$0.357	$0.357
5	TGP Z0	($0.079)	($0.079)	($0.079)	($0.079)	($0.079)	($0.079)
6	TGP Z1	($0.034)	($0.034)	($0.034)	($0.034)	($0.034)	($0.034)
7	TGP Z4	$ 0.140	$ 0.140	$ 0.140	$ 0.140	$ 0.140	$ 0.140
8	PEAK 1	NA	NA	NA	NA	NA	NA
9	PEAK 2	NA	NA	NA	NA	NA	NA
10	PEAK 3	NA	NA	NA	NA	NA	NA
11	LNG	$0.395	$0.395	$0.395	$0.395	$0.395	$0.395
12	W10 Supply	$0.063	$0.063	$0.063	$0.063	$0.063	$0.063
13	W10 AMA Spot	$0.645	$0.645	$0.645	$0.645	$0.645	$0.645
14							
15	NYMEX NG	$2.712	$2.802	$2.870	$2.904	$2.914	$2.967

Northern Utilities, Inc.
Transportation Contract Rates

Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 7	$ 5.9771	$ 5.9771	$ 5.9771	$ 5.9771	$ 5.9771	$ 5.9771
3	Granite	FT-NN	N/A	N/A		Page 8	$ 3.1000	$ 3.1000	$ 3.1000	$ 3.1000	$ 3.1000	$ 3.1000
4	Iroquois	RTS-1	Zone 1	Zone 1		Page 9	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971
5	PNGTS	FT	N/A	N/A		Page 17	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456
6	PNGTS	FT (Seasonal)	N/A	N/A	1	Page 17	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666
7	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396
11	Texas Eastern	CDS	ELA	M1		Page 23	$ 2.3701	$ 2.3701	$ 2.3701	$ 2.3701	$ 2.3701	$ 2.3701
12	Texas Eastern	CDS	ETX	M1		Page 23	$ 2.1665	$ 2.1665	$ 2.1665	$ 2.1665	$ 2.1665	$ 2.1665
13	Texas Eastern	CDS	STX	M1		Page 23	$ 6.7878	$ 6.7878	$ 6.7878	$ 6.7878	$ 6.7878	$ 6.7878
14	Texas Eastern	CDS	WLA	M1		Page 23	$ 2.8175	$ 2.8175	$ 2.8175	$ 2.8175	$ 2.8175	$ 2.8175
15	Texas Eastern	CDS	M1	M3		Page 23	$ 10.9950	$ 10.9950	$ 10.9950	$ 10.9950	$ 10.9950	$ 10.9950
16	Texas Eastern	CDS	M3	M3		Page 23	$ 5.3070	$ 5.3070	$ 5.3070	$ 5.3070	$ 5.3070	$ 5.3070
17	Texas Eastern	FT-1/FTS	M3	M3	2	Pages 23, 24	$ 5.7440	$ 5.7440	$ 5.7440	$ 5.7440	$ 5.7440	$ 5.7440
18	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 30.0972	$ 30.0972	$ 30.0972	$ 30.0972	$ 30.0972	$ 30.0972
19	TransCanada	FT	Parkway	Iroquois		Page 26	$ 12.3344	$ 12.3344	$ 12.3344	$ 12.3344	$ 12.3344	$ 12.3344
20	Union	M12	Dawn	Parkway		Page 26	$ 2.5670	$ 2.5670	$ 2.5670	$ 2.5670	$ 2.5670	$ 2.5670
21	Vector	FT-1	Alliance	Dawn		Page 36	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042
22	Vector	FT-1	W-10	Dawn	3	Pages 33, 34	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625
23	Vector	FT-1	Alliance	St. Clair	4	Page 37	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745
24	Vector Canada	FT-1	St. Clair	Dawn		Page 26	$ 0.5089	$ 0.5089	$ 0.5089	$ 0.5089	$ 0.5089	$ 0.5089

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
25	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131	$ 0.0131
27	Granite	FT-NN	N/A	N/A		Page 8	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
28	Iroquois	RTS-1	Zone 1	Zone 1	5	Pages 9, 11	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
29	LNG Trucking		Everett, MA	Lewiston, ME		Page 13	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900
30	PNGTS	FT	N/A	N/A		Page 17	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
31	Tennessee	FT-A	Zone 0	Zone 4		Page 20	$ 0.3035	$ 0.3035	$ 0.3035	$ 0.3035	$ 0.3035	$ 0.3035
32	Tennessee	FT-A	Zone 0	Zone 6		Page 20	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505
33	Tennessee	FT-A	Zone L	Zone 4		Page 20	$ 0.2580	$ 0.2580	$ 0.2580	$ 0.2580	$ 0.2580	$ 0.2580
34	Tennessee	FT-A	Zone L	Zone 6		Page 20	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055
35	Tennessee	FT-A	Zone 4	Zone 6		Page 20	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181
36	Tennessee	FT-A	Zone 5	Zone 6		Page 20	$ 0.0892	$ 0.0892	$ 0.0892	$ 0.0892	$ 0.0892	$ 0.0892
37	Texas Eastern	CDS	ELA	M3		Page 23	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371
38	Texas Eastern	CDS	ETX	M3		Page 23	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371
39	Texas Eastern	CDS	STX	M3		Page 23	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371
40	Texas Eastern	CDS	WLA	M3		Page 23	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371	$ 0.0371
41	Texas Eastern	FT-1/FTS	M3	M3		Page 23	$ 0.0105	$ 0.0105	$ 0.0105	$ 0.0105	$ 0.0105	$ 0.0105
42	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 0.0894	$ 0.0894	$ 0.0894	$ 0.0894	$ 0.0894	$ 0.0894
43	TransCanada	FT	Parkway	Iroquois		Page 26	$ 0.0218	$ 0.0218	$ 0.0218	$ 0.0218	$ 0.0218	$ 0.0218
44	Union	M12	Dawn	Parkway		Page 26	$ -	$ -	$ -	$ -	$ -	$ -
45	Vector	FT-1	Alliance	W-10 Storage		Page 34	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Vector	FT-1	Alliance	Dawn		Page 34	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
47	Vector	FT-1	W-10 Storage	Dawn		Page 34	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019

Transportation Fuel Rates

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

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

Northern Utilities, Inc. Underground Storage Contract Rates										
Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 22	$ 0.0211	$ 1.5400	$ 0.0204	0.00%	$ 0.0204	1.59%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.5480				
3	Texas Eastern	FSS-1		Page 24	$ 0.1293	$ 0.8950				
4	W-10	Storage		Pages 40, 41, 42			$ -	0.50%	$ -	1.10%

REDACTED

Northern Utilities, Inc. Peaking Supply Demand Cost				
Line	Peaking Supply Contract	Notes	Reference	Monthly Demand Cost
1	LNG Supply		Page 43	[redacted]
2	Peaking Supply 1		Page 44	
3	Peaking Supply 2		Page 45	
4	Peaking Supply 3		Page 46	

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2010

•RATE SCHEDULE AFT-1

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
(F-1/WS-1)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-2/F-3)	$ 6.5734	$\boxed{\$0.0131}$	$0.0131	$0.2292	$0.0131	$0.2161
(F-4)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(STB/SS-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(FTP)	$11.8368	$0.0019	$0.0019	$0.3911	$0.0019	$0.3892
(PSS-T)	$ 9.7854	$0.0019	$0.0019	$0.3236	$0.0019	$0.3217
(AFT-2)	$\boxed{\$ 6.1138}$	$\boxed{\$0.0019}$	$0.0019	$0.2029	$0.0019	$0.2010
(AFT-3)	$10.7554	$0.0019	$0.0019	$0.3555	$0.0019	$0.3536
(AFT-5)	$12.6265	$0.0019	$0.0019	$0.4170	$0.0019	$0.4151
(ITP)	$13.0110	$0.0019	$0.0019	$0.4297	$0.0019	$0.4278
(X-35)	$10.2027	$0.0019	$0.0019	$0.3373	$0.0019	$0.3354
X-39	$13.2089	$0.0019	$0.0019	$0.4362	$0.0019	$0.4343
Incremental Surcharges						
Hubline	**$ 1.8607**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0612**
Secondary 1/		**$0.0612**	**$0.0000**			
Tiverton	**$ 1.6424**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0540**
Ramapo	**$ 7.5608**	**$0.0000**	**$0.0000**	**$0.2486**	**$0.0000**	**$0.2486**

•RATE SCHEDULE AFT-1S

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
(F-1/WS-1)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-2/F-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-4)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0031	$0.0864
(STB/SS-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
AFT-E	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0058		$0.0600		
AFT-4	$ 3.5211	$0.0032		$0.1190		
AFT-CL:						
Canal	$ 2.0858	$0.0019	$0.0019	$0.0705	$0.0019	$0.0686
Middletown	$ 3.2764	$0.0019	$0.0019	$0.1096	$0.0019	$0.1077
Cleary	$ 1.4529	$0.0019	$0.0019	$0.0497	$0.0019	$0.0478
Lake Road	$ 0.6476	$0.0019	$0.0019	$0.0232	$0.0019	$0.0213
Brayton Pt.	$ 1.2700	$0.0019	$0.0019	$0.0437	$0.0019	$0.0418
Manchester	$ 2.4500	$0.0019	$0.0019	$0.0824	$0.0019	$0.0805
Bellingham	$ 0.9714	$0.0019	$0.0019	$0.0338	$0.0019	$0.0319
Phelps Dodge	$ 0.0000	$0.0185	$0.0019	$0.0185	$0.0019	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0019	$0.2994	$0.0019	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0019	$0.1447	$0.0019	$0.1428
J-2 Facility	$ 4.6346	$0.0019	$0.0019	$0.1543	$0.0019	$0.1524
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min
AIT-1	$0.2440	$0.0095	$0.2440	$0.0095
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0437	$0.0019	$0.0437	$0.0019
Manchester	$0.0824	$0.0019	$0.0824	$0.0019
Canal	$0.0705	$0.0019	$0.0705	$0.0019
Cape Cod	$0.2994	$0.0019	$0.2994	$0.0019
Northeast Gateway	$0.1447	$0.0019	$0.1447	$0.0019
J-2 Facility	$0.1543	$0.0019	$0.1543	$0.0019
PAL	$0.2440	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0019.

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
<u>System Services</u>		
Winter	Dec 1 - Mar 31	1.02%
Spring, Summer and Fall	Apr 1 - Nov 30	0.72%
<u>Incremental Ramapo Services</u>		
Winter	Dec 1 - Mar 31	1.92%
Spring, Summer and Fall	Apr 1 - Nov 30	1.31%

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

•The Summary

ALGONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

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

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

	$/Dth		
	Base Tariff Rate	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$3.1000		$3.1000
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0018	$0.0018
Minimum	$0.0000	$0.0018	$0.0018
Authorized Overrun Commodity Charge:			
Maximum	$0.1019	$0.0018	$0.1037
Minimum	$0.0000	$0.0018	$0.0018
Fuel and Losses Percentage			0.35%
Volumetric Reservation Charge			
Maximum	$0.1019	$0.0018	$0.1037
Minimum	$0.0000	$0.0018	$0.0018

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

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

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

(Footnotes continued on Sheet 4.01)

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

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

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

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

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	0.0019

DEFERRED ASSET SURCHARGE:
Commodity

Zone 1	0.0003
Zone 2	0.0002
Inter-Zone	0.0005

MEASUREMENT VARIANCE/FUEL USE FACTOR:

Minimum	0.00%
Maximum (Non-Eastchester Shipper)	1.00%
Maximum (Eastchester Shipper)	4.50%
Maximum (Brookfield Shipper)	1.20%

Historic Fuel Retention Ratios

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

CONFIDENTIAL

REDACTED

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

CONFIDENTIAL

LNG TRANSPORTATION RATE AGREEMENT

REDACTED

DATE: June 24, 2010

CONFIDENTIAL

CARRIER:

[redacted]

SHIPPER:

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

EFFECTIVE DATE: 11/01/10

EXPIRATION DATE: 10/31/11

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

OTHER TERMS AND CONDITIONS:

[redacted]

4. This agreement is strictly confidential.

CARRIER: [redacted]

[redacted]

SHIPPER: Northern Utilities Inc.

By: ______________________

Robert Furino

Its: Director of Energy Contracts

CONFIDENTIAL

[redacted]

REDACTED

CONFIDENTIAL

EXHIBIT 2

DIESEL FUEL ADJUSTMENT TABLE

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

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

[redacted]

Experience you can count on

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

U.S. Energy Information Administration

Weekly Retail On-Highway Diesel Prices *

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

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

Click on a Region to view graph of that Region

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

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

Reference

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

Related Links

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

Statement of Transportation Rates
(Rates per DTH)

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

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

Historic Fuel Retention Ratios

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

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

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

Daily Base Reservation Rate 1/

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

Maximum Reservation Rates 2 /

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

Notes:

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

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
Commodity Rates 1/, 2/ 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0080		$0.0247	$0.0372	$0.0457	$0.0534	$0.0604	$0.0727
L		$0.0040						
1	$0.0100		$0.0179	$0.0312	$0.0376	$0.0451	$0.0547	$0.0632
2	$0.0362		$0.0191	$0.0039	$0.0072	$0.0132	$0.0223	$0.0305
3	$0.0445		$0.0366	$0.0070	$0.0020	$0.0183	$0.0261	$0.0348
4	$0.0534		$0.0429	$0.0191	$0.0227	$0.0073	$0.0112	$0.0200
5	$0.0604		$0.0547	$0.0223	$0.0261	$0.0111	$0.0111	$0.0147
6	$0.0727		$0.0632	$0.0305	$0.0348	$0.0188	$0.0094	$0.0051

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0080		$0.0247	$0.0372	$0.0457	$0.3035	$0.2945	$0.3505
L		$0.0040						
1	$0.0100		$0.0179	$0.0312	$0.0376	$0.2580	$0.2676	$0.3055
2	$0.0362		$0.0191	$0.0039	$0.0072	$0.0833	$0.1337	$0.1507
3	$0.0445		$0.0366	$0.0070	$0.0020	$0.1114	$0.1543	$0.1713
4	$0.0534		$0.0429	$0.0191	$0.0227	$0.0513	$0.0728	$0.1181
5	$0.0604		$0.0547	$0.0223	$0.0261	$0.0724	$0.0718	$0.0892
6	$0.0727		$0.0632	$0.0305	$0.0348	$0.1116	$0.0602	$0.0365

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018
2/ The applicable F&LR's determined pursuant to Article XXXVII of the General Terms and Conditions are listed on Sheet No. 32. For service that is rendered entirely by displacement, Shipper shall render only the quantity of gas associated with Losses of 0.09%.
3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.
4/ Includes a per Dth charge for the Hurricane Surcharge Adjustment per Article XXXIX of the General Terms and Conditions and listed on Sheet No. 34.

FUEL AND LOSS RETENTION PERCENTAGE (F&LR) 1/,2/,3/,4/

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

Notes:

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.09%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.09%.
3/ The F&LR percentages listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ F&LR determined pursuant to Article XXXVII of the General Terms and Conditions.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA			
Deliverability Rate	$2.8100	$2.8100 1/	
Space Rate	$0.0286	$0.0286 1/	
Injection Rate	$0.0073	$0.0073 3/	1.59%
Withdrawal Rate	$0.0073	$0.0073 3/	
Overrun Rate	$0.3372	$0.3372 3/	
FIRM STORAGE SERVICE (FS) - MARKET AREA			
Deliverability Rate	$1.5400	$1.5400 1/	
Space Rate	$0.0211	$0.0211 1/	
Injection Rate	$0.0087	$0.0087 3/	1.59%
Withdrawal Rate	$0.0087	$0.0087 3/	
Overrun Rate	$0.1848	$0.1848 3/	

Notes:

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions associated with Losses is equal to 0.09%.
3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

PROPOSED EFFECTIVE RATES 8/01/2011

•RESERVATION CHARGES

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

7(C) RATE SCHEDULES	
FTS	5.3500
FTS-2	7.9590
FTS-4	7.7250
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND CHARGES	
Access Area	0.0020
M1-M1	0.0030
M1-M2	0.0040
M1-M3	0.0050

•USAGE CHARGES

CDS & FT-1 USAGE-1

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

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0346	0.0309	0.0293	0.0293	0.0206		
from M2	0.0682	0.0645	0.0629	0.0629	0.0542	0.0378	
from M3	0.0912	0.0875	0.0859	0.0859	0.0772	0.0608	0.0272

SCT USAGE-1

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

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

IT-1 USAGE-1

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

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1900						

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

•OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage	
			In Path	Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3410 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	$\boxed{0.6600}$		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	10.2010		0.37%	
FT-1/NC	6.5590		0.00%	
FT-1/RIV	10.4380		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	1.2690 2/		0.00%	
FT-1/TME	14.5169		4.28%	4.69%
FT-1/TME2	23.3313		3.69%	4.63%
FT-1/TME3	23.4630		0.75%	
MLS-1/FH	0.6340		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270	0.0305 3/	0.01%	
MLS-1/HS	6.1130	0.2010 3/	0.01%	

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

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

•STORAGE SERVICES

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

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31

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

April 1 through November 30

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

NON-ASA RATE SCHEDULES

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

ASA STORAGE RATE SCHEDULES

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.34%	3.09%
FSS-1,ISS-1	0.97%	0.97%
INJECTIONS	0.97%	0.97%
INVENTORY LEVEL	0.07%	0.07%

- **SURCHARGES**

```
  ACA Surcharge
Commodity  0.0019
```

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

Canadian Fixed Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Demand Toll	$CAD / GJ	$ 10.16778	Page 30
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 1.03785	Page 28
4	Total Demand Toll	$CAD / GJ	$ 11.20563	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0433	Page 27
6	Total Demand Toll	$US / GJ	$ 11.6908	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Total Demand Toll	$US / Dth	$ 12.3344	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Demand Toll	$CAD / GJ	$ 22.70383	Page 29
12	Union Dawn Surcharge	$CAD / GJ	$ 0.09828	Page 28
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 4.54054	Page 28
14	Total Demand Toll	$CAD / GJ	$ 27.34265	Sum Lines Above.
15	$CAD to $US	Ratio	1.0433	Page 27
16	Total Demand Toll	$US / GJ	$ 28.5266	Line 13 times Line 14
17	GJ per Dth	Ratio	1.0551	
18	Total Demand Toll	$US / Dth	$ 30.0972	Line 15 divided by Line 16
19				
20	Dawn to Parkway on Union Pipeline			
21	Total Demand Toll	$CAD / GJ	$ 2.3320	Page 31
22	$CAD to $US	Ratio	1.0433	Page 27
23	Total Demand Toll	$US / GJ	$ 2.4330	Line 13 times Line 14
24	GJ per Dth	Ratio	1.0551	
25	Total Demand Toll	$US / Dth	$ 2.5670	Line 15 divided by Line 16
26				
27	St. Clair to Dawn on Vector Canada			
28	Total Demand Toll	$CAD / GJ	$ 0.4623	Page 35
29	$CAD to $US	Ratio	1.0433	Page 27
30	Total Demand Toll	$US / GJ	$ 0.4823	Line 13 times Line 14
31	GJ per Dth	Ratio	1.0551	
32	Total Demand Toll	$US / Dth	$ 0.5089	Line 15 divided by Line 16

Canadian Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Variable Toll	$CAD / GJ	$ 0.01983	Page 30
3	Delivery Pressure Commodity Toll	$CAD / GJ	$ -	Page 28
4	Variable Transportation Rate	$CAD / GJ	$ 0.01983	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0433	Page 27
6	Variable Transportation Rate	$US / GJ	$ 0.0207	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ 0.0218	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Commodity Rate	$CAD / GJ	$ 0.04889	Page 29
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.03226	Page 28
13	Variable Transportation Rate	$CAD / GJ	$ 0.08115	Line 11 plus Line 12
14	$CAD to $US	Ratio	1.0433	Page 27
15	Variable Transportation Rate	$US / GJ	$ 0.0847	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ 0.0894	Line 15 divided by Line 16

Daily currency converter

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

Currency Converter (Using rates from July 14, 2011)

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

Convert

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

TransCanada
In business to deliver

Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

System Average Unit Cost of Transportation

Line No	Particulars	Net Revenue Requirement ($000's)	Allocation Base		Annual Unit Cost		Daily Unit Cost	
	(a)	(b)	(c)		(d)		(e)	
1	Fixed Energy	76,148	3,938,676	GJ	19.3333983638	$/GJ	0.0529682147	$/GJ
2	Transmission - Fixed	1,169,509	4,862,440,154	GJ-KM	0.2405190214	$/GJ-Km	0.0006589562	$/GJ-Km
3	Transmission - Variable	48,954	1,053,676,682,785	GJ-KM	-	$/GJ-Km	0.0000464601	$/GJ-Km

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
4	Centram MDA	4.46187	0.00722	0.1539
5	Union WDA	31.41463	0.06896	1.1018
6	Union NDA	12.30579	0.02546	0.4300
7	Union EDA	8.00131	0.01505	0.2781
8	KPUC EDA	7.70246	0.01412	0.2674
9	GMIT EDA	14.16801	0.02929	0.4951
10	Enbridge CDA	1.69730	0.00024	0.0560
11	Enbridge EDA	4.84530	0.00757	0.1669
12	Cornwall	10.94987	0.02165	0.3816
13	Philipsburg	14.44301	0.02974	0.5046

Firm Transportation - Short Notice

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
14	Kirkwall to Thorold - CDA	3.87336	0.00487	0.1322
15	Parkway to Goreway - CDA	2.39507	0.00144	0.0802
16	Parkway to Victoria Square #2 CDA	3.17490	0.00326	0.1077

Delivery Pressure

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

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

Union Dawn Receipt Point Surcharge

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
24	Union Dawn Receipt Point Surcharge	0.09828	0.00000	0.0032

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

Line No.		Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) ii (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	(i)	Union Dawn	Empress	53.99115	0.12142	1.8965	2.0862
2	(i)	Union Dawn	Transgas SSDA	45.27755	0.10213	1.5907	1.7498
3	(i)	Union Dawn	Centram SSDA	41.73330	0.09300	1.4651	1.6116
4	(i)	Union Dawn	Centram MDA	36.35048	0.08114	1.2762	1.4038
5	(i)	Union Dawn	Centrat MDA	36.32483	0.08047	1.2747	1.4022
6	(i)	Union Dawn	Union WDA	35.43270	0.07837	1.2433	1.3676
7	(i)	Union Dawn	Nipigon WDA	31.91972	0.07026	1.1197	1.2317
8	(i)	Union Dawn	Union NDA	16.85361	0.03600	0.5901	0.6491
9	(i)	Union Dawn	Calstock NDA	25.29041	0.05489	0.8864	0.9750
10	(i)	Union Dawn	Tunis NDA	20.07115	0.04279	0.7027	0.7730
11	(i)	Union Dawn	GMIT NDA	16.23988	0.03373	0.5676	0.6244
12	(i)	Union Dawn	Union SSMDA	13.80764	0.02827	0.4822	0.5304
13	(i)	Union Dawn	Union NCDA	9.84488	0.01915	0.3429	0.3772
14	(i)	Union Dawn	Union CDA	6.30424	0.01066	0.2180	0.2398
15	(i)	Union Dawn	Enbridge CDA	7.49321	0.01360	0.2600	0.2860
16	(i)	Union Dawn	Union EDA	12.70526	0.02589	0.4436	0.4880
17	(i)	Union Dawn	Enbridge EDA	15.52514	0.03229	0.5427	0.5970
18	(i)	Union Dawn	GMIT EDA	18.81384	0.03999	0.6585	0.7244
19	(i)	Union Dawn	KPUC EDA	12.24987	0.02466	0.4274	0.4701
20	(i)	Union Dawn	North Bay Junction	13.36368	0.02724	0.4666	0.5133
21	(i)	Union Dawn	Enbridge SWDA	1.61112	0.00000	0.0530	0.0583
22	(i)	Union Dawn	Union SWDA	1.81836	0.00025	0.0601	0.0661
23	(i)	Union Dawn	Spruce	36.32483	0.08047	1.2747	1.4022
24	(i)	Union Dawn	Emerson 1	33.48049	0.07387	1.1746	1.2921
25	(i)	Union Dawn	Emerson 2	33.48049	0.07387	1.1746	1.2921
26	(i)	Union Dawn	St. Clair	2.08875	0.00111	0.0698	0.0768
27	(i)	Union Dawn	Dawn Export	1.61112	0.00000	0.0530	0.0583
28	(i)	Union Dawn	Kirkwall	5.39268	0.00877	0.1861	0.2047
29	(i)	Union Dawn	Niagara Falls	7.62509	0.01394	0.2646	0.2911
30	(i)	Union Dawn	Chippawa	7.67300	0.01405	0.2664	0.2930
31	(i)	Union Dawn	Iroquois	14.71519	0.03038	0.5142	0.5656
32	(i)	Union Dawn	Cornwall	15.56423	0.03234	0.5440	0.5984
33	(i)	Union Dawn	Napierville	18.64367	0.03948	0.6524	0.7176
34	(i)	Union Dawn	Philipsburg	18.99363	0.04029	0.6647	0.7312
35	(i)	Union Dawn	East Hereford	22.70383	0.04889	0.7953	0.8748
36	(i)	Union Dawn	Welwyn	41.73330	0.09300	1.4651	1.6116
37		Enbridge CDA	Empress	59.63212	0.13449	2.0950	2.3045
38		Enbridge CDA	Transgas SSDA	50.91651	0.11520	1.7892	1.9681
39		Enbridge CDA	Centram SSDA	47.37427	0.10608	1.6636	1.8300
40		Enbridge CDA	Centram MDA	41.98183	0.09419	1.4744	1.6218
41		Enbridge CDA	Centrat MDA	40.25370	0.08955	1.4130	1.5543
42		Enbridge CDA	Union WDA	31.07610	0.06816	1.0899	1.1989
43		Enbridge CDA	Nipigon WDA	27.28392	0.05947	0.9565	1.0522
44		Enbridge CDA	Union NDA	12.21780	0.02521	0.4269	0.4696
45		Enbridge CDA	Calstock NDA	20.65481	0.04410	0.7232	0.7955
46		Enbridge CDA	Tunis NDA	15.43555	0.03200	0.5395	0.5935
47		Enbridge CDA	GMIT NDA	11.60428	0.02294	0.4044	0.4448
48		Enbridge CDA	Union SSMDA	19.68772	0.04187	0.6892	0.7581
49		Enbridge CDA	Union NCDA	5.20928	0.00836	0.1797	0.1977
50		Enbridge CDA	Union CDA	3.45710	0.00387	0.1176	0.1294
51		Enbridge CDA	Enbridge CDA	1.61112	0.00000	0.0530	0.0583
52		Enbridge CDA	Union EDA	7.63512	0.01407	0.2651	0.2916
53		Enbridge CDA	Enbridge EDA	10.44758	0.02045	0.3640	0.4004
54		Enbridge CDA	GMIT EDA	13.74250	0.02816	0.4800	0.5280
55		Enbridge CDA	KPUC EDA	7.18033	0.01283	0.2489	0.2738
56		Enbridge CDA	North Bay Junction	8.73008	0.01646	0.3035	0.3339
57		Enbridge CDA	Enbridge SWDA	7.49100	0.01360	0.2599	0.2859
58		Enbridge CDA	Union SWDA	7.69845	0.01385	0.2670	0.2937
59		Enbridge CDA	Spruce	40.25370	0.08955	1.4130	1.5543
60		Enbridge CDA	Emerson 1	39.36098	0.08747	1.3816	1.5198
61		Enbridge CDA	Emerson 2	39.36098	0.08747	1.3816	1.5198
62		Enbridge CDA	St. Clair	7.97064	0.01471	0.2767	0.3044
63		Enbridge CDA	Dawn Export	7.49321	0.01360	0.2600	0.2860
64		Enbridge CDA	Kirkwall	3.71165	0.00484	0.1268	0.1395
65		Enbridge CDA	Niagara Falls	5.05535	0.00803	0.1742	0.1916
66		Enbridge CDA	Chippawa	5.11849	0.00817	0.1765	0.1942
67		Enbridge CDA	Iroquois	9.64565	0.01855	0.3357	0.3693
68		Enbridge CDA	Cornwall	10.49469	0.02052	0.3655	0.4021
69		Enbridge CDA	Napierville	13.57413	0.02766	0.4740	0.5214
70		Enbridge CDA	Philipsburg	13.92409	0.02847	0.4863	0.5349
71		Enbridge CDA	East Hereford	17.63429	0.03707	0.6169	0.6786
72		Enbridge CDA	Welwyn	47.37427	0.10608	1.6636	1.8300
73		Enbridge EDA	Empress	61.58233	0.13902	2.1636	2.3800
74		Enbridge EDA	Transgas SSDA	52.86873	0.11974	1.8579	2.0437
75		Enbridge EDA	Centram SSDA	49.32448	0.11061	1.7322	1.9054
76		Enbridge EDA	Centram MDA	43.96591	0.09881	1.5443	1.6987
77		Enbridge EDA	Centrat MDA	41.50601	0.09248	1.4571	1.6028
78		Enbridge EDA	Union WDA	32.19772	0.07081	1.1294	1.2423

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) ii (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Parkway Belt	Centrat MDA	40.47278	0.09008	1.4207	1.5628
2	Union Parkway Belt	Union WDA	31.16449	0.06841	1.0930	1.2023
3	Union Parkway Belt	Nipigon WDA	27.37231	0.05971	0.9596	1.0556
4	Union Parkway Belt	Union NDA	12.30620	0.02546	0.4301	0.4731
5	Union Parkway Belt	Calstock NDA	20.74300	0.04435	0.7264	0.7990
6	Union Parkway Belt	Tunis NDA	15.52374	0.03225	0.5427	0.5970
7	Union Parkway Belt	GMIT NDA	11.69247	0.02319	0.4076	0.4484
8	Union Parkway Belt	Union SSMDA	18.35505	0.03881	0.6423	0.7065
9	Union Parkway Belt	Union NCDA	5.29747	0.00861	0.1828	0.2011
10	Union Parkway Belt	Union CDA	2.07011	0.00053	0.0686	0.0755
11	Union Parkway Belt	Enbridge CDA	3.14523	0.00350	0.1069	0.1176
12	Union Parkway Belt	Union EDA	8.15784	0.01535	0.2836	0.3120
13	Union Parkway Belt	Enbridge EDA	10.97773	0.02175	0.3827	0.4210
14	Union Parkway Belt	GMIT EDA	14.26643	0.02945	0.4985	0.5484
15	Union Parkway Belt	KPUC EDA	7.70246	0.01412	0.2673	0.2940
16	Union Parkway Belt	North Bay Junction	8.81626	0.01670	0.3065	0.3372
17	Union Parkway Belt	Enbridge SWDA	6.15853	0.01054	0.2130	0.2343
18	Union Parkway Belt	Union SWDA	6.36578	0.01079	0.2201	0.2421
19	Union Parkway Belt	Spruce	40.47278	0.09008	1.4207	1.5628
20	Union Parkway Belt	Emerson 1	38.02790	0.08441	1.3346	1.4681
21	Union Parkway Belt	Emerson 2	38.02790	0.08441	1.3346	1.4681
22	Union Parkway Belt	St. Clair	6.63616	0.01165	0.2299	0.2529
23	Union Parkway Belt	Dawn Export	6.15853	0.01054	0.2130	0.2343
24	Union Parkway Belt	Kirkwall	2.37697	0.00178	0.0799	0.0879
25	Union Parkway Belt	Niagara Falls	4.27106	0.00617	0.1466	0.1613
26	Union Parkway Belt	Chippawa	4.31896	0.00628	0.1483	0.1631
27	Union Parkway Belt	Iroquois	$\boxed{10.16778}$	$\boxed{0.01983}$	0.3541	0.3895
28	Union Parkway Belt	Cornwall	11.01681	0.02180	0.3840	0.4224
29	Union Parkway Belt	Napierville	14.09626	0.02894	0.4923	0.5415
30	Union Parkway Belt	Philipsburg	14.44621	0.02975	0.5047	0.5552
31	Union Parkway Belt	East Hereford	18.15642	0.03835	0.6353	0.6988
32	Union Parkway Belt	Welwyn	46.28071	0.10354	1.6251	1.7876
33	Union NCDA	Empress	56.87397	0.12803	1.9978	2.1976
34	Union NCDA	Transgas SSDA	48.16057	0.10875	1.6922	1.8614
35	Union NCDA	Centram SSDA	44.61612	0.09962	1.5664	1.7230
36	Union NCDA	Centram MDA	39.26096	0.08782	1.3786	1.5165
37	Union NCDA	Centrat MDA	36.78642	0.08147	1.2909	1.4200
38	Union NCDA	Union WDA	27.47814	0.05979	0.9632	1.0595
39	Union NCDA	Nipigon WDA	23.68595	0.05110	0.8298	0.9128
40	Union NCDA	Union NDA	8.61984	0.01685	0.3003	0.3303
41	Union NCDA	Calstock NDA	17.05665	0.03574	0.5965	0.6562
42	Union NCDA	Tunis NDA	11.83738	0.02364	0.4128	0.4541
43	Union NCDA	GMIT NDA	8.00632	0.01458	0.2778	0.3056
44	Union NCDA	Union SSMDA	22.04140	0.04742	0.7720	0.8492
45	Union NCDA	Union NCDA	1.61112	0.00000	0.0530	0.0583
46	Union NCDA	Union CDA	5.75646	0.00915	0.1985	0.2184
47	Union NCDA	Enbridge CDA	5.20928	0.00836	0.1797	0.1977
48	Union NCDA	Union EDA	9.89018	0.01945	0.3447	0.3792
49	Union NCDA	Enbridge EDA	11.86043	0.02382	0.4137	0.4551
50	Union NCDA	GMIT EDA	15.84503	0.03319	0.5541	0.6095
51	Union NCDA	KPUC EDA	9.52199	0.01840	0.3315	0.3647
52	Union NCDA	North Bay Junction	5.12991	0.00809	0.1768	0.1945
53	Union NCDA	Enbridge SWDA	9.84488	0.01915	0.3429	0.3772
54	Union NCDA	Union SWDA	10.05213	0.01940	0.3499	0.3849
55	Union NCDA	Spruce	36.78642	0.08147	1.2909	1.4200
56	Union NCDA	Emerson 1	39.62795	0.08806	1.3909	1.5300
57	Union NCDA	Emerson 2	39.62795	0.08806	1.3909	1.5300
58	Union NCDA	St. Clair	10.32252	0.02026	0.3597	0.3957
59	Union NCDA	Dawn Export	9.84488	0.01915	0.3429	0.3772
60	Union NCDA	Kirkwall	6.06332	0.01039	0.2097	0.2307
61	Union NCDA	Niagara Falls	7.95741	0.01478	0.2764	0.3040
62	Union NCDA	Chippawa	8.00531	0.01489	0.2781	0.3059
63	Union NCDA	Iroquois	11.79008	0.02368	0.4113	0.4524
64	Union NCDA	Cornwall	12.59522	0.02554	0.4396	0.4836
65	Union NCDA	Napierville	15.67466	0.03268	0.5480	0.6028
66	Union NCDA	Philipsburg	16.02462	0.03349	0.5603	0.6163
67	Union NCDA	East Hereford	19.73483	0.04209	0.6909	0.7600
68	Union NCDA	Welwyn	44.61612	0.09962	1.5664	1.7230
69	Union SSMDA	Empress	45.07892	0.10076	1.5828	1.7411
70	Union SSMDA	Transgas SSDA	36.36551	0.08147	1.2771	1.4048
71	Union SSMDA	Centram SSDA	32.82107	0.07234	1.1513	1.2664
72	Union SSMDA	Centram MDA	27.43845	0.06048	0.9626	1.0589
73	Union SSMDA	Centrat MDA	27.41259	0.05981	0.9610	1.0571
74	Union SSMDA	Union WDA	37.50337	0.08335	1.3164	1.4480
75	Union SSMDA	Nipigon WDA	40.51306	0.09017	1.4221	1.5643
76	Union SSMDA	Union NDA	29.05013	0.06427	1.0194	1.1213
77	Union SSMDA	Calstock NDA	37.48693	0.08316	1.3156	1.4472
78	Union SSMDA	Tunis NDA	32.26767	0.07106	1.1320	1.2452

TRANSPORTATION RATES

(A) Applicability

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

(B) Services

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

(C) Rates

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

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

Authorized Overrun (3)

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

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

Current M12 Rates and Fuel

Current OEB approved rates effective April 1, 2011

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

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

Notes:

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

If you have any questions please contact your Account Manager

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

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

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

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/ Maximum	Minimum	Zone 2 2/ Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$7.7745	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0019	0.0019	0.0019	0.0019

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

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

Negotiated Rates:

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

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

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

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

CAPACITY RELEASE TRANSACTIONS
CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s): Maximum Daily Reservation Quantity Dth

   Alliance Interconnect **17,172**

8. Primary Delivery Point(s): Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect **17,172**

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTe

Name: DON TUCHFARSKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: (___) 508-870-2294

CAPACITY RELEASE TRANSACTIONS
CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s): Maximum Daily Reservation Quantity Dth

   Washington 10 Interconnect **17,086**

8. Primary Delivery Point(s): Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect **17,086**

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTC

Name: DON TULCHINSKY

Title: ANALYST

Telephone: (___) 508-836 7257

Fax: (___) 508-870-2244

Historic TransCanada Fuel Loss Percentages

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

Historic Fuel Retention Ratios

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

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

SHIPPER:

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

INVOICES, STATEMENTS AND NOMINATIONS

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

EXHIBIT I

Rates:

Monthly Deliverability Rate:	$ 2.4754 per Dth
Monthly Capacity Rate:	$ 0.0238 per Dth
Injection Rate:	$ 0.00 per Dth
Withdrawal Rate:	$ 0.00 per Dth
Authorized Overrun Rate:	$ 0.05 per Dth
Interruptible Rate:	$ 0.05 per Dth

Service Parameters:

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

Maximum Daily Injection Quantity (MDIQ):

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

Maximum Daily Withdrawal Quantity (MDWQ):

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

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

DTE Energy

Gas Midstream Services

Home | MichCon Storage & Transportation | MichCon Pipeline | DTE Gas Storage | DTE Pipeline

- Our Services
- Notices
- Contact Us
- Forms
- Tariffs
- Getting Started

DTE Gas Storage - Washington 10 Historic Fuel Rates

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

DTEEnergy.com | Privacy Policy | Terms of Use

CONFIDENTIAL

REDACTED

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

[redacted]

Date: July 26, 2011

Transaction Confirmation: [redacted]

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

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

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

(i) Commodity Rate:

[redacted]

(ii) Call Payment:

[redacted]

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

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

Performance Obligation and Contract Quantity: Firm Liquid Service:

[redacted]

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

Special Conditions:

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

REDACTED

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

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

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

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

Contract Price: [redacted]

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

Performance Obligation and Contract Quantity: (Select One)

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

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

Special Conditions:

[redacted]

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

 [redacted]

NAESB Standard 6.3.1

REDACTED

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

Date: September 20, 2011

Transaction Confirmation #: ______________

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated April 1, 2005. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:
[redacted]
Base Contract No. ______________
Transporter: ______________
Transporter Contract Number: ______________

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

[redacted]

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

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):
____ MMBtus/day
☐ EFP

Firm (Variable Quantity):
[redacted]
(see special condition 1)
subject to Section 4.2. at election of
☒ Buyer or ☐ Seller

Interruptible:
Up to ______ MMBtus/day

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

Special Conditions:

[redacted]

Seller: [redacted]
By:
Title:
Date:

Buyer: Northern Utilities, Inc.
By: [signature] FXW
Title: TREASURER
Date: 10/18/11

NAESB Standard 6.3.1

REDACTED

CONFIDENTIAL

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

[redacted]	**July 15, 2011** Transaction Confirmation #: ______

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

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

Contract Price: See Special Conditions

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

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

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

Special Conditions:

[redacted]

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

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2011 through October 2012		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (3,032,033)	Page 2
NH Division Storage Contract Capacity Assignment	$ (248,676)	Page 3
NH Division Peaking Demand	$ (311,869)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 206,395	Page 5
NH Division Net PNGTS Litigation Costs Assigned to Retail Suppliers	$ (34,007)	Page 6
NH Division Capacity Assignment Demand Revenue - Updated Forecast	$ (3,420,191)	Sum of Items Above
NH Division Capacity Assignment Demand Revenue - Previous Forecast	$ (3,574,514)	Winter COG, Schedule 5B
Net Change in Forecast	$ 154,323	Sum of Items Above

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

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	NH Annual Cap Assign Credit
Algonquin	93002F	$ 308,943	$ -	$ -	Y	4,211	-	(346)	-	$ (25,384)
Algonquin	93201A1C	$ 83,632	$ 6,097	$ -	N	NA	NA	-	-	$ -
Granite	10-010-FT-NN	$ 1,094,461	$ 1,321,679	$ 1,303,860	Y	29,421	35,529	(2,419)	(2,912)	$ (198,313)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	(540)	-	$ (42,749)
PNGTS	1997-003	$ 531,242	$ -	$ -	Y	1,100	-	(90)	-	$ (43,465)
PNGTS	1997-004	$ -	$ 12,616,989	$ -	Y	-	33,000	-	(2,705)	$ (1,034,211)
Tennessee	5083	$ 1,351,367	$ -	$ -	Y	4,605	-	(379)	-	$ (111,220)
Tennessee	5083	$ 2,225,558	$ -	$ -	Y	8,550	-	(703)	-	$ (182,990)
Tennessee	5265	$ -	$ 270,275	$ -	Y	-	2,653	-	(217)	$ (22,107)
Tennessee	5292	$ 125,521	$ -	$ -	Y	1,406	-	(116)	-	$ (10,356)
Tennessee	46314	$ 35,338	$ -	$ -	Y	950	-	(78)	-	$ (2,901)
Tennessee	31861	$ 198,727	$ -	$ -	Y	2,226	-	(183)	-	$ (16,337)
Tennessee	39735	$ 82,937	$ -	$ -	Y	929	-	(76)	-	$ (6,785)
Tennessee	41099	$ 380,937	$ -	$ -	Y	4,267	-	(351)	-	$ (31,336)
Texas Eastern	800464	$ 234	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 1,303	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 609	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 7,784	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800384	$ 66,214	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 939	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800436	$ 4,056	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	33322	$ -	$ 2,046,610	$ -	Y	-	34,000	-	(2,787)	$ (167,762)
TransCanada	33322	$ -	$ 10,233,048	$ -	Y	-	34,000	-	(2,787)	$ (838,809)
TransCanada	29594	$ 146,459	$ -	$ -	Y	5,937	-	(488)	-	$ (12,038)
TransCanada	29594	$ 732,293	$ -	$ -	Y	5,937	-	(488)	-	$ (60,192)
Union	M12205	$ 184,916	$ -	$ -	Y	6,003	-	(494)	-	$ (15,217)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	(1,407)	$ (128,389)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	(1,400)	$ (31,938)
Vector	FT-1-NUI-0122	$ 566,295	$ -	$ -	Y	6,070	-	(499)	-	$ (46,554)
Vector	FT-1-NUI-C0122	$ 36,238	$ -	$ -	Y	6,070	-	(499)	-	$ (2,979)

Total NH Capacity Assignment Credits $ (3,032,033)

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

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 144,075	Y	N	(21,256)	(348)	$ (11,809)
W-10	01052	$ 2,890,000	Y	Y	(278,668)	(2,787)	$ (236,868)

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

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

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

Month	Retail Supplier 1	Retail Supplier 2	Retail Supplier 3	Retail Supplier 4	Retail Supplier 5	Retail Supplier 6	Retail Supplier 7	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-11	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Dec-11	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Jan-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Feb-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Mar-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)
Apr-12	1,105	396	219	3,224	-	-	177	5,121	$ 10.15	$ (51,978)

Total Division Peaking Demand Revenue $ (311,869)

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2011 through October 2012

Asset Management Agreeement Revenue					
Resources	Projected Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	$ (890,000)	Yes	Pipeline	8.22%	$ 73,184
Wash 10 via Vector, TCPL, PNGTS	$ (1,620,000)	Yes	Storage	8.22%	$ 133,211
Tennessee Niagara	$ (125,000)	No	Pipeline	8.22%	$ -
Tennessee Long-Haul	$ (1,452,000)	No	Pipeline	8.22%	$ -
Total Asset Management	$ (4,087,000)				$ 206,395

Capacity Release Revenue					
Resources	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Texas Eastern Contract 800384	$ (66,701)	No	Pipeline	8.22%	$ -
AGT Contract 93201A1C	$ (98,779)	No	Pipeline	8.22%	$ -
Tennessee 5265	$ (103,375)	No	Pipeline	8.20%	$ -
Granite 10-010-FT-NN	$ (27,675)	No	Pipeline	8.20%	$ -
Granite 10-010-FT-NN	$ (12,160)	No	Pipeline	8.20%	$ -
Granite 10-010-FT-NN	$ (4,800)	No	Pipeline	8.20%	$ -
Total Capacity Release	$ (313,490)				$ -

Total Asset Management and Capacity Release Revenue	$ (4,400,490)				$ 206,395

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

PNGTS Litigation Costs	$ 414,873

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

Northern Utilities, Inc.
NH Division Peaking Capacity Assignment Demand Rate
November 2011 through April 2012

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

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

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

Schedules 6A and 6B

Northern Utilities, Inc.
Commodity Cost by Supply Source
May 2012 through October 2012

Description	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Season
Pipeline Supplies							
Chicago	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lewiston Baseload	$ 239,630	$ 238,650	$ 251,875	$ 254,510	$ 247,050	$ 259,393	$ 1,491,108
PNGTS	$ 95,343	$ 94,968	$ 100,241	$ 101,295	$ 98,328	$ 103,248	$ 593,424
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee Production	$ 239,741	$ 107,220	$ 63,688	$ 67,423	$ 140,193	$ 499,926	$ 1,118,192
Tenn Zone 4 Spot	$ 226,682	$ 226,016	$ 238,739	$ 241,333	$ 234,287	$ 246,141	$ 1,413,197
W10 AMA Spot	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Pipeline	$ 801,396	$ 666,854	$ 654,543	$ 664,562	$ 719,858	$ 1,108,708	$ 4,615,921
Underground Storage							
Tennessee Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 41,917
Subtotal Peaking	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 41,917
Total Commodity Cost	$ 808,860	$ 673,885	$ 661,642	$ 671,520	$ 726,478	$ 1,115,452	$ 4,657,839

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) May 2012 through October 2012							
Description	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Season
Pipeline Supplies							
Chicago	0	0	0	0	0	0	0
Lewiston Baseload	77,500	75,000	77,500	77,500	75,000	77,500	460,000
PNGTS	30,892	29,895	30,892	30,892	29,895	30,892	183,356
Niagara	0	0	0	0	0	0	0
Tennessee Production	77,314	33,538	19,487	20,408	42,300	148,522	341,568
Tenn Zone 4 Spot	75,233	72,806	75,233	75,233	72,806	75,233	446,542
W10 AMA Spot	0	0	0	0	0	0	0
Subtotal Pipeline	260,938	211,239	203,111	204,032	220,001	332,146	1,431,466
Underground Storage							
Tennessee Storage	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
Subtotal Storage	0	0	0	0	0	0	0
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Subtotal Peaking	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Total Delivered (Dth)	262,333	212,589	204,506	205,427	221,351	333,541	1,439,746

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) May 2012 through October 2012							
Description	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Season
Pipeline Supplies							
Chicago							
Lewiston Baseload	$ 3.092	$ 3.182	$ 3.250	$ 3.284	$ 3.294	$ 3.347	$ 3.242
PNGTS	$ 3.086	$ 3.177	$ 3.245	$ 3.279	$ 3.289	$ 3.342	$ 3.236
Niagara							
Tennessee Production	$ 3.101	$ 3.197	$ 3.268	$ 3.304	$ 3.314	$ 3.366	$ 3.274
Tenn Zone 4 Spot	$ 3.013	$ 3.104	$ 3.173	$ 3.208	$ 3.218	$ 3.272	$ 3.165
W10 AMA Spot							
Subtotal Pipeline	$ 3.071	$ 3.157	$ 3.223	$ 3.257	$ 3.272	$ 3.338	$ 3.225
Underground Storage							
Tennessee Storage							
Washington 10 Storage							
Subtotal Storage							
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3							
LNG	$ 5.350	$ 5.208	$ 5.089	$ 4.988	$ 4.904	$ 4.835	$ 5.062
Subtotal Peaking	$ 5.350	$ 5.208	$ 5.089	$ 4.988	$ 4.904	$ 4.835	$ 5.062
Total Cost per Dth	$ 3.083	$ 3.170	$ 3.235	$ 3.269	$ 3.282	$ 3.344	$ 3.235

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-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Sum Lines 64, 84 and 104	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Chicago Supply Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with Union)								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 68 of Page 2							
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 46 of Page 2							
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27									
28	Transportation Segment 3								
29	Union Pipeline (Contract M12205)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with TransCanada)								
32	Received Volume	Line 14	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 66 of Page 2							
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 44 of Page 2							
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37									
38	Transportation Segment 4								
39	TransCanada Pipeline (Contract 41235)								
40	Receipt Point: Parkway								
41	Delivery Point: Iroquois								
42	Received Volume	Line 24	-	-	-	-	-	-	-
43	Fuel Loss Rate	Att to Sch 5A, Line 65 of Page 2							
44	Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	-	-	-	-
45	Variable Transportation Rate	Att to Sch 5A, Line 43 of Page 2							
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47									
48	Transportation Segment 5								
49	Iroquois Pipeline (Contract R181001)								
50	Receipt Point: Waddington								
51	Delivery Point: Wright (Interconnection with Tennessee)								
52	Received Volume	Line 44	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 51 of Page 2							
54	Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57									
58	Transporation Segment 6A								
59	Tennessee Gas Pipeline (Contract 31861)								
60	Receipt Point: Mendon								
61	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
62	Received Volume	Line 54	-	-	-	-	-	-	-
63	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2							
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	-	-	-	-	-	-	-
65	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
66	Variable Transportation Costs	Line 64 times Line 65	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67									
68	Transportation Segment 6B								
69	Tennessee Gas Pipeline (Contract 31861)								
70	Receipt Point: Mendon								
71	Delivery Point: Pleasant St. (Interconnection with Granite)								
72	Received Volume	Line 54	-	-	-	-	-	-	-
73	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2							
74	Delivered Volume	Line 72 times (1 - Line 73)	-	-	-	-	-	-	-
75	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
76	Variable Transportation Costs	Line 74 times Line 75	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77									
78	Transportation Segment 7B								
79	Granite State Gas Transmission (Contract 10-010-FT-NN)								
80	Receipt Point: Pleasant St.								
81	Delivery Point: Northern City Gates								
82	Received Volume	Line 74	-	-	-	-	-	-	-
83	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
84	City Gate Delivered Volume	Line 82 times (1 - Line 83)	-	-	-	-	-	-	-
85	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
86	Variable Transportation Costs	Line 84 times Line 85	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87									
88	Transportation Segment 6C								
89	Tennessee Gas Pipeline (Contract 41099)								
90	Receipt Point: Wright								
91	Delivery Point: Mendon (Interconnection with Algonquin)								
92	Received Volume	Line 54	-	-	-	-	-	-	-
93	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2							
94	Delivered Volume	Line 92 times (1 - Line 93)	-	-	-	-	-	-	-
95	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
96	Variable Transportation Costs	Line 94 times Line 95	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97									
98	Transportation Segment 7C								
99	Algonquin Gas Transmission (Contract 93200F)								
100	Receipt Point: Mendon								
101	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
102	Received Volume	Line 94	-	-	-	-	-	-	-
103	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2							
104	City Gate Delivered Volume	Line 102 times (1 - Line 103)	-	-	-	-	-	-	-
105	Variable Transportation Rate	Att to Sch 5A, Line 25 of Page 2							
106	Variable Transportation Costs	Line 104 times Line 105	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	77,500	75,000	77,500	77,500	75,000	77,500	460,000
2	City Gate Delivered Volume	Line 1	77,500	75,000	77,500	77,500	75,000	77,500	460,000
3	Total Purchase Cost	Line 14	$ 239,630	$ 238,650	$ 251,875	$ 254,510	$ 247,050	$ 259,393	$ 1,491,108
4	Variable Transportation Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 239,630	$ 238,650	$ 251,875	$ 254,510	$ 247,050	$ 259,393	$ 1,491,108
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.092	$ 3.182	$ 3.250	$ 3.284	$ 3.294	$ 3.347	$ 3.242
7									
8	Portland Supply Costs								
9	Purchased Volumes	Sendout Optimization	77,500	75,000	77,500	77,500	75,000	77,500	460,000
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	$ 2.862
11	NYMEX Cost	Line 9 times Line 10	$ 210,180	$ 210,150	$ 222,425	$ 225,060	$ 218,550	$ 229,943	$ 1,316,308
12	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1	$ 0.380	$ 0.380	$ 0.380	$ 0.380	$ 0.380	$ 0.380	$ 0.380
13	NYMEX Basis Costs	Line 9 times Line 12	$ 29,450	$ 28,500	$ 29,450	$ 29,450	$ 28,500	$ 29,450	$ 174,800
14	Total Purchase Price	Line 10 plus Line 12	$ 3.092	$ 3.182	$ 3.250	$ 3.284	$ 3.294	$ 3.347	$ 3.242
15	Total Purchase Cost	Line 11 plus Line 13	$ 239,630	$ 238,650	$ 251,875	$ 254,510	$ 247,050	$ 259,393	$ 1,491,108

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
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 14	$ 95,232	$ 94,860	$ 100,130	$ 101,184	$ 98,220	$ 103,137	$ 592,763
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 111	$ 108	$ 111	$ 111	$ 108	$ 111	$ 661
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 95,343	$ 94,968	$ 100,241	$ 101,295	$ 98,328	$ 103,248	$ 593,424
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.086	$ 3.177	$ 3.245	$ 3.279	$ 3.289	$ 3.342	$ 3.236
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	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	$ 2.862
11	NYMEX Cost	Line 9 times Line 10	$ 84,072	$ 84,060	$ 88,970	$ 90,024	$ 87,420	$ 91,977	$ 526,523
12	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	$ 0.360	$ 0.360	$ 0.360	$ 0.360	$ 0.360	$ 0.360	$ 0.360
13	NYMEX Basis Costs	Line 9 times Line 12	$ 11,160	$ 10,800	$ 11,160	$ 11,160	$ 10,800	$ 11,160	$ 66,240
14	Total Purchase Price	Line 10 plus Line 12	$ 3.072	$ 3.162	$ 3.230	$ 3.264	$ 3.274	$ 3.327	$ 3.222
15	Total Purchase Cost	Line 11 plus Line 13	$ 95,232	$ 94,860	$ 100,130	$ 101,184	$ 98,220	$ 103,137	$ 592,763
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	Att to Sch 5A, Line 52 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	31,000	30,000	31,000	31,000	30,000	31,000	184,000
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 56	$ 54	$ 56	$ 56	$ 54	$ 56	$ 331
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	31,000	30,000	31,000	31,000	30,000	31,000	184,000
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	30,892	29,895	30,892	30,892	29,895	30,892	183,356
35	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 56	$ 54	$ 56	$ 56	$ 54	$ 56	$ 330

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-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Sum Lines 24, 54 and 44	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26, 56, 36 and 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1A								
19	Tennessee Gas Pipeline (Contract 5292)								
20	Receipt Point: Niagara								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2							
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27									
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 39375)								
30	Receipt Point: Niagara								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 9	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2							
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	-	-	-	-	-	-	-
43	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	-	-	-	-
45	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47									
48	Transportation Segment 1C								
49	Tennessee Gas Pipeline (Contract 46314)								
50	Receipt Point: Niagara								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 9	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 58 of Page 2							
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	62,907	32,743	19,487	20,408	42,300	111,361	289,206
2	City Gate Volumes - Z1	Line 2 of Page 6	14,406	795	-	-	-	37,160	52,362
3	Total City Gate Volumes	Line 1 plus Line 2	77,314	33,538	19,487	20,408	42,300	148,522	341,568
4	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 195,220	$ 104,688	$ 63,688	$ 67,423	$ 140,193	$ 375,244	$ 946,457
5	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 44,521	$ 2,532	$ -	$ -	$ -	$ 124,682	$ 171,735
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 239,741	$ 107,220	$ 63,688	$ 67,423	$ 140,193	$ 499,926	$ 1,118,192
7	Average Delivered Price	Line 6 divided by Line 3	$ 3.101	$ 3.197	$ 3.268	$ 3.304	$ 3.314	$ 3.366	$ 3.274

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 32	65,697	34,195	20,351	21,313	44,176	116,300	302,031
2	City Gate Delivered Volume	Line 44	62,907	32,743	19,487	20,408	42,300	111,361	289,206
3	Total Purchase Price	Line 24	$ 2.633	$ 2.723	$ 2.791	$ 2.825	$ 2.835	$ 2.888	$ 2.772
4	Total Purchase Cost	Line 2 times Line 3	$ 172,980	$ 93,113	$ 56,799	$ 60,208	$ 125,239	$ 335,874	$ 844,213
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 22,240	$ 11,576	$ 6,889	$ 7,215	$ 14,954	$ 39,370	$ 102,243
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 195,220	$ 104,688	$ 63,688	$ 67,423	$ 140,193	$ 375,244	$ 946,457
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.103	$ 3.197	$ 3.268	$ 3.304	$ 3.314	$ 3.370	$ 3.273
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	56,092	54,282	56,092	44,302	-	-	210,767
11	Storage Delivered Volume	Line 54	54,465	52,708	54,465	43,017	-	-	204,655
12	Total Purchase Price	Line 24	$ 2.633	$ 2.723	$ 2.791	$ 2.825	$ 2.835	$ 2.888	$ 2.772
13	Total Purchase Cost	Line 10 times Line 12	$ 147,689	$ 147,811	$ 156,552	$ 125,153	$ -	$ -	$ 577,204
14	Variable Transportation Costs	Line 56	$ 16,530	$ 15,997	$ 16,530	$ 13,056	$ -	$ -	$ 62,113
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ 164,219	$ 163,807	$ 173,082	$ 138,208	$ -	$ -	$ 639,317
16	Average Delivered Price	Line 15 divided by Line 11	$ 3.015	$ 3.108	$ 3.178	$ 3.213			$ 3.124
17									
18	Tennessee Zone 0 Supply Costs								
19	Purchased Volumes	Sendout Optimization	121,789	88,477	76,442	65,615	44,176	116,300	512,799
20	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	$ 2.851
21	NYMEX Cost	Line 25 times Line 26	$ 330,291	$ 247,913	$ 219,390	$ 190,545	$ 128,729	$ 345,062	$ 1,461,929
22	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)
23	NYMEX Basis Costs	Line 25 times Line 28	$ (9,621)	$ (6,990)	$ (6,039)	$ (5,184)	$ (3,490)	$ (9,188)	$ (40,511)
24	Total Purchase Price	Line 26 plus Line 28	$ 2.633	$ 2.723	$ 2.791	$ 2.825	$ 2.835	$ 2.888	$ 2.772
25	Total Purchase Cost	Line 27 plus Line 29	$ 320,669	$ 240,923	$ 213,351	$ 185,361	$ 125,239	$ 335,874	$ 1,421,418
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1A								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	65,697	34,195	20,351	21,313	44,176	116,300	302,031
33	Fuel Loss Rate	Att to Sch 5A, Line 54 of Page 2	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%
34	Delivered Volume	Line 32 times (1 - Line 33)	63,128	32,858	19,555	20,479	42,449	111,753	290,222
35	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505	$ 0.3505
36	Variable Transportation Costs	Line 34 times Line 35	$ 22,126	$ 11,517	$ 6,854	$ 7,178	$ 14,878	$ 39,169	$ 101,723
37									
38	Transportation Segment 2A								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	63,128	32,858	19,555	20,479	42,449	111,753	290,222
43	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	62,907	32,743	19,487	20,408	42,300	111,361	289,206
45	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 113	$ 59	$ 35	$ 37	$ 76	$ 200	$ 521
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	56,092	54,282	56,092	44,302	-	-	210,767
53	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2	2.90%	2.90%	2.90%	2.90%			2.90%
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	54,465	52,708	54,465	43,017	-	-	204,655
55	Variable Transportation Rate	Att to Sch 5A, Line 31 of Page 2	$ 0.3035	$ 0.3035	$ 0.3035	$ 0.3035			$ 0.3035
56	Variable Transportation Costs	Line 54 times Line 55	$ 16,530	$ 15,997	$ 16,530	$ 13,056	$ -	$ -	$ 62,113

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 32	14,966	826	-	-	-	38,603	54,395
2	City Gate Delivered Volume	Line 44	14,406	795	-	-	-	37,160	52,362
3	Total Purchase Price	Line 24	$ 2.678	$ 2.768				$ 2.933	$ 2.860
4	Total Purchase Cost	Line 2 times Line 3	$ 40,079	$ 2,287	$ -	$ -	$ -	$ 113,223	$ 155,588
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 4,443	$ 245	$ -	$ -	$ -	$ 11,459	$ 16,147
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 44,521	$ 2,532	$ -	$ -	$ -	$ 124,682	$ 171,735
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.090	$ 3.184				$ 3.355	$ 3.280
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24	$ 2.678	$ 2.768				$ 2.933	$ 2.860
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	Tennessee Zone L Supply Costs								
19	Purchased Volumes	Sendout Optimization	14,966	826	-	-	-	38,603	54,395
20	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	$ 2.894
21	NYMEX Cost	Line 25 times Line 26	$ 40,587	$ 2,315	$ -	$ -	$ -	$ 114,536	$ 157,438
22	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1	$ (0.034)	$ (0.034)				$ (0.034)	$ (0.034)
23	NYMEX Basis Costs	Line 25 times Line 28	$ (509)	$ (28)	$ -	$ -	$ -	$ (1,313)	$ (1,849)
24	Total Purchase Price	Line 26 plus Line 28	$ 2.678	$ 2.768				$ 2.933	$ 2.860
25	Total Purchase Cost	Line 27 plus Line 29	$ 40,079	$ 2,287	$ -	$ -	$ -	$ 113,223	$ 155,588
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone L								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	14,966	826	-	-	-	38,603	54,395
33	Fuel Loss Rate	Att to Sch 5A, Line 56 of Page 2	3.40%	3.40%				3.40%	3.40%
34	Delivered Volume	Line 32 times (1 - Line 33)	14,457	798	-	-	-	37,291	52,546
35	Variable Transportation Rate	Att to Sch 5A, Line 34 of Page 2	$ 0.3055	$ 0.3055				$ 0.3055	$ 0.3055
36	Variable Transportation Costs	Line 34 times Line 35	$ 4,417	$ 244	$ -	$ -	$ -	$ 11,392	$ 16,053
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	14,457	798	-	-	-	37,291	52,546
43	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	14,406	795	-	-	-	37,160	52,362
45	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 26	$ 1	$ -	$ -	$ -	$ 67	$ 94
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone L								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 55 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	76,308	73,846	76,308	76,308	73,846	76,308	452,925
2	City Gate Delivered Volume	Sum Lines 24, 0 and 0	75,233	72,806	75,233	75,233	72,806	75,233	446,542
3	Total Purchase Cost	Line 14	$ 217,630	$ 217,256	$ 229,687	$ 232,281	$ 225,527	$ 237,089	$ 1,359,470
4	Variable Transportation Costs	Sum Lines 26, 0, 36 and 0	$ 9,052	$ 8,760	$ 9,052	$ 9,052	$ 8,760	$ 9,052	$ 53,727
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 226,682	$ 226,016	$ 238,739	$ 241,333	$ 234,287	$ 246,141	$ 1,413,197
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.013	$ 3.104	$ 3.173	$ 3.208	$ 3.218	$ 3.272	$ 3.165
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	76,308	73,846	76,308	76,308	73,846	76,308	452,925
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	$ 2.862
11	NYMEX Cost	Line 9 times Line 10	$ 206,947	$ 206,918	$ 219,004	$ 221,598	$ 215,188	$ 226,406	$ 1,296,061
12	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1	$ 0.140	$ 0.140	$ 0.140	$ 0.140	$ 0.140	$ 0.140	$ 0.140
13	NYMEX Basis Costs	Line 9 times Line 12	$ 10,683	$ 10,338	$ 10,683	$ 10,683	$ 10,338	$ 10,683	$ 63,409
14	Total Purchase Price	Line 10 plus Line 12	$ 2.852	$ 2.942	$ 3.010	$ 3.044	$ 3.054	$ 3.107	$ 3.002
15	Total Purchase Cost	Line 11 plus Line 13	$ 217,630	$ 217,256	$ 229,687	$ 232,281	$ 225,527	$ 237,089	$ 1,359,470
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA Withdrawal Meter								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	76,308	73,846	76,308	76,308	73,846	76,308	452,925
23	Fuel Loss Rate	Att to Sch 5A, Line 57 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
24	Delivered Volume	Line 22 times (1 - Line 23)	75,499	73,064	75,499	75,499	73,064	75,499	448,124
25	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181	$ 0.1181
26	Variable Transportation Costs	Line 24 times Line 25	$ 8,916	$ 8,629	$ 8,916	$ 8,916	$ 8,629	$ 8,916	$ 52,923
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	75,499	73,064	75,499	75,499	73,064	75,499	448,124
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	75,233	72,806	75,233	75,233	72,806	75,233	446,542
35	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 135	$ 131	$ 135	$ 135	$ 131	$ 135	$ 804

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 34	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 13 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	PNGTS (Contract 1997-004)								
19	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
20	Delivery Point: Granite (Westbrook, Newington, Eliot)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 36	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 28 and 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Tennessee FS-MA Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8, Page 1							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 1 of Page 3	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 times Line 14	-	-	-	-	-	-	-
16	Total Withdrawal Costs	Line 9 minus Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17		Line 11 plus Line 13							
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 2								
20	Tennessee Gas Pipeline (Contract 5265)								
21	Receipt Point: Tennessee FS-MA Withdrawal Meter								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume		-	-	-	-	-	-	-
24	Fuel Loss Rate	Line 16							
25	Delivered Volume	Att to Sch 5A, Line 57 of Page 2	-	-	-	-	-	-	-
26	Variable Transportation Rate	Line 24 times (1 - Line 25)							
27	Variable Transportation Costs	Att to Sch 5A, Line 35 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Line 26 times Line 27							
29	Transportation Segment 3								
30	Granite State Gas Transmission (Contract 10-010-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume		-	-	-	-	-	-	-
34	Fuel Loss Rate	Line 26	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
35	City Gate Delivered Volume	Att to Sch 5A, Line 50 of Page 2	-	-	-	-	-	-	-
36	Variable Transportation Rate	Line 34 times (1 - Line 35)	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
37	Variable Transportation Costs	Att to Sch 5A, Line 27 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Line 36 times Line 37							

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 66	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 28, 38, 48, 58 and 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Washington 10 Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
10	Withdrawal Rate	Att to Sch 5A, Line 4 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 4 of Page 3	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 times Line 14	-	-	-	-	-	-	-
16	Total Withdrawal Costs	Line 9 minus Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17		Line 11 plus Line 13							
18	<u>Transportation Fuel Losses and Variable Charges</u>								
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		-	-	-	-	-	-	-
24	Fuel Loss Rate	Line 16							
25	Delivered Volume	Att to Sch 5A, Line 69 of Page 2	-	-	-	-	-	-	-
26	Variable Transportation Rate	Line 24 times (1 - Line 25)							
27	Variable Transportation Costs	Att to Sch 5A, Line 47 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Line 26 times Line 27							
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		-	-	-	-	-	-	-
34	Fuel Loss Rate	Line 26							
35	Delivered Volume	Att to Sch 5A, Line 69 of Page 2	-	-	-	-	-	-	-
36	Variable Transportation Rate	Line 34 times (1 - Line 35)							
37	Variable Transportation Costs	Att to Sch 5A, Line 47 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Line 36 times Line 37							
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		-	-	-	-	-	-	-
44	Fuel Loss Rate	Line 36							
45	Delivered Volume	Att to Sch 5A, Line 64 of Page 2	-	-	-	-	-	-	-
46	Variable Transportation Rate	Line 44 times (1 - Line 45)							
47	Variable Transportation Costs	Att to Sch 5A, Line 42 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48		Line 46 times Line 47							
49	Transportation Segment 4								
50	PNGTS (Contract 1997-004)								
51	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
52	Delivery Point: Granite (Westbrook, Newington, Eliot)								
53	Received Volume		-	-	-	-	-	-	-
54	Fuel Loss Rate	Line 46							
55	Delivered Volume	Att to Sch 5A, Line 52 of Page 2	-	-	-	-	-	-	-
56	Variable Transportation Rate	Line 54 times (1 - Line 55)							
57	Variable Transportation Costs	Att to Sch 5A, Line 30 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58		Line 56 times Line 57							
59	Transportation Segment 5								
60	Granite State Gas Transmission (Contract 10-010-FT-NN)								
61	Receipt Point: Westbrook, Newington, Eliot								
62	Delivery Point: Northern City Gates								
63	Received Volume		-	-	-	-	-	-	-
64	Fuel Loss Rate	Line 56	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
65	City Gate Delivered Volume	Att to Sch 5A, Line 50 of Page 2	-	-	-	-	-	-	-
66	Variable Transportation Rate	Line 64 times (1 - Line 65)	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
67	Variable Transportation Costs	Att to Sch 5A, Line 27 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Line 66 times Line 67							

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Peaking Supply 1 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 8 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Peaking Supply 2 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 9 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 3 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 10 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Gross Withdrawn Volume	Line 9	1,395	1,350	1,395	1,395	1,350	1,395	8,280
2	City Gate Delivered Volume	Line 15	1,395	1,350	1,395	1,395	1,350	1,395	8,280
3	Total Withdrawal Costs	Line 16	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 41,917
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 41,917
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.350	$ 5.208	$ 5.089	$ 4.988	$ 4.904	$ 4.835	$ 5.062
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	1,395	1,350	1,395	1,395	1,350	1,395	8,280
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	$ 5.3505	$ 5.2084	$ 5.0886	$ 4.9882	$ 4.9040	$ 4.8347	$ 5.0625
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 41,917
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,395	1,350	1,395	1,395	1,350	1,395	8,280
16	Total Withdrawal Costs	Line 11 plus Line 13	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 41,917

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

Line	LNG Storage Deliveries	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	2012 Off-Peak
1	Purchased Volumes	Line 22	1,395	1,350	1,395	1,395	1,350	1,395	8,280
2	Storage Delivered Volume	Line 24	1,395	1,350	1,395	1,395	1,350	1,395	8,280
3	Total Purchase Price	Line 15	$ 3.107	$ 3.197	$ 3.265	$ 3.299	$ 3.309	$ 3.362	$ 3.257
4	Total Purchase Cost	Line 10 times Line 12	$ 4,334	$ 4,316	$ 4,555	$ 4,602	$ 4,467	$ 4,690	$ 26,964
5	Variable Transportation Costs	Line 26	$ 1,381	$ 1,337	$ 1,381	$ 1,381	$ 1,337	$ 1,381	$ 8,197
6	Total Storage Delivered Costs	Line 13 plus Line 14	$ 5,715	$ 5,652	$ 5,936	$ 5,983	$ 5,804	$ 6,071	$ 35,161
7	Average Delivered Price	Line 15 divided by Line 11	$ 4.097	$ 4.187	$ 4.255	$ 4.289	$ 4.299	$ 4.352	$ 4.247
8									
9	Peaking Supply 1 Costs (Segment 1)								
10	Purchased Volumes	Sendout Optimization	1,395	1,350	1,395	1,395	1,350	1,395	8,280
11	LNG Supply Prices	Att to Sch 5A, Line 15 of Page 1	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967	$ 2.862
12	LNG Supply Costs	Line 9 times Line 10	$ 3,783	$ 3,783	$ 4,004	$ 4,051	$ 3,934	$ 4,139	$ 23,694
13	NYMEX Basis Price	Att to Sch 5A, Line 11 of Page 1	$ 0.395	$ 0.395	$ 0.395	$ 0.395	$ 0.395	$ 0.395	$ 0.395
14	NYMEX Basis Costs	Line 19 times Line 22	$ 551	$ 533	$ 551	$ 551	$ 533	$ 551	$ 3,271
15	Total Purchase Price	Line 20 plus Line 22	$ 3.107	$ 3.197	$ 3.265	$ 3.299	$ 3.309	$ 3.362	$ 3.257
16	Total Purchase Cost	Line 14 times (1 - Line 15)	$ 4,334	$ 4,316	$ 4,555	$ 4,602	$ 4,467	$ 4,690	$ 26,964
17									
18	Transportation Segment 3								
19	Trucking Contract (TransGas)								
20	Receipt Point: Distrigas Terminal								
21	Delivery Point: Northern LNG Facility (Lewiston, ME)								
22	Received Volume	Line 19 minus Line 31	1,395	1,350	1,395	1,395	1,350	1,395	8,280
23	Fuel Loss Rate	N/A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Storage Delivered Volume	Line 22 times (1 - Line 23)	1,395	1,350	1,395	1,395	1,350	1,395	8,280
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900	$ 0.9900
26	Variable Transportation Costs	Line 24 times Line 25	$ 1,381	$ 1,337	$ 1,381	$ 1,381	$ 1,337	$ 1,381	$ 8,197

Schedule 7

Northern Utilities, Inc. Hedging Gains and Losses May 2012 through October 2012 As of 2/27/2012			
Description	May-12	Oct-12	Summer
NYMEX Contracts	12	14	26
Average Purchase Price	$ 4.002	$ 4.207	$ 4.112
Current NYMEX Price	$ 2.712	$ 2.967	$ 2.849
Hedging (Gains) and Losses	$ 154,800	$ 173,600	$ 328,400

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Summer 2012 vs. Summer 2011

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2011- 2012																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4395	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$131.85								
Over	50 units @	$0.3283	$19.37	$32.83	$44.98	$45.31	$38.08	$26.92	$207.49								
	COG 1	$1.0837	$118.12						$118.12								
	COG 2	$1.0837		$162.56					$162.56								
	COG 3	$1.1560			$216.17				$216.17								
	COG 4	$1.1560				$217.33			$217.33								
	COG 5	$1.2961					$215.15		$215.15								
	COG 6	$1.2961						$171.09	$171.09								
Winter Period 2011-2012 Avg. COG		$1.1786															
	LDAC	$0.0440	$4.80	$6.60	$8.23	$8.27	$7.30	$5.81	$41.01								
Summer 2012																	
Customer Charge	units @	$ 9.50								$ 9.50	$9.50	$9.50	$9.50	$ 9.50	$9.50	$57.00	
First	50 units @	$0.4395								$21.98	$21.98	$13.19	$13.19	$18.46	$21.98	$110.75	
Over	50 units @	$0.3283								$13.13	$1.64	$0.00	$0.00	$0.00	$6.89	$21.67	
	COG 1	$0.3371								$30.34						$30.34	
	COG 2	$0.3371									$18.54					$18.54	
	COG 3	$0.3371										$10.11				$10.11	
	COG 4	$0.3371											$10.11			$10.11	
	COG 5	$0.3371												$14.16		$14.16	
	COG 6	$0.3371													$23.93	$23.93	
Summer Period 2012 Avg. COG		$0.3371															
	LDAC	$ 0.0440								$3.96	$2.42	$1.32	$1.32	$1.85	$3.12	$13.99	
	TOTAL		$173.76	$233.46	$300.85	$302.38	$292.01	$235.29	$1,537.76	$78.91	$54.08	$34.12	$34.12	$43.97	$65.43	$310.61	$1,848.37

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2010 - 2011																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	COG 1	$1.0987	$119.76						$119.76								
	COG 2	$1.0736		$161.04					$161.04								
	COG 3	$1.1199			$209.42				$209.42								
	COG 4	$1.1615				$218.36			$218.36								
	COG 5	$1.1615					$192.81		$192.81								
	COG 6	$1.1615						$153.32	$153.32								
Winter Period 2010-2011 Avg. COG		$1.1295															
	LDAC	$ 0.0456	$4.97	$6.84	$8.53	$8.57	$7.57	$6.02	$42.50								
Summer 2011																	
Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31				$53.33	
First	50 units (Temp)	$0.4395											$13.19	$18.46	$21.98	$53.62	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00				$13.46	
Over	50 units (Temp)	$0.3283											$0.00	$0.00	$6.89	$6.89	
	COG 1	$0.6673								$60.06						$60.06	
	COG 2	$0.6673									$36.70					$36.70	
	COG 3	$0.5992										$17.98				$17.98	
	COG 4	$0.6685											$20.06			$20.06	
	COG 5	$0.5570												$23.39		$23.39	
	COG 6	$0.5570													$39.55	$39.55	
Summer Period 2011 Avg. COG		$0.6194															
	LDAC	$ 0.0456								$4.10	$2.51	$1.37	$1.37	$1.92	$3.24	$14.50	
	TOTAL		$172.38	$227.79	$288.92	$298.21	$265.07	$213.87	$1,466.24	$106.13	$70.71	$41.15	$44.11	$53.27	$81.15	$396.53	$1,862.76
	Change		$1.38	$5.67	$11.93	$4.17	$26.94	$21.42	$71.52	($27.23)	($16.64)	($7.03)	($9.99)	($9.30)	($15.73)	**($85.91)**	($14.39)
	% Chg		0.80%	2.49%	4.13%	1.40%	10.16%	10.02%	4.88%	-25.65%	-23.53%	-17.09%	-22.65%	-17.46%	-19.38%	**-21.67%**	-0.77%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Summer 2012 vs. Summer 2011

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2011 - 2012																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3370	$25.28	$25.28	$25.28	$25.28	$25.28	$25.28	$151.65								
Over	75 units @	$0.2300	$27.14	$44.62	$51.29	$43.01	$36.57	$22.08	$224.71								
	COG 1	$1.1166	$215.50						$215.50								
	COG 2	$1.1166		$300.37					$300.37								
	COG 3	$1.1889			$354.29				$354.29								
	COG 4	$1.1889				$311.49			$311.49								
	COG 5	$1.3290					$310.99		$310.99								
	COG 6	$1.3290						$227.26	$227.26								
Winter Period 2011-2012 Avg. COG		$1.2115															
	LDAC	$0.0233	$4.50	$6.27	$6.94	$6.10	$5.45	$3.98	$33.25								
Summer 2012																	
Customer Charge	units @	$ 18.70								$ 18.70	$18.70	$18.70	$18.70	$ 18.70	$18.70	$112.20	
First	75 units @	$0.3370								$25.28	$25.28	$24.26	$24.26	$25.28	$25.28	$149.63	
Over	75 units @	$0.2300								$9.66	$1.38	$0.00	$0.00	$3.22	$15.41	$29.67	
	COG 1	$0.3704								$43.34						$43.34	
	COG 2	$0.3704									$30.00					$30.00	
	COG 3	$0.3704										$26.67				$26.67	
	COG 4	$0.3704											$26.67			$26.67	
	COG 5	$0.3704												$32.97		$32.97	
	COG 6	$0.3704													$52.60	$52.60	
Summer Period 2012 Avg. COG		$0.3704															
	LDAC	$ 0.0233								$2.73	$1.89	$1.68	$1.68	$2.07	$3.31	$13.35	
	TOTAL		$291.12	$395.23	$456.50	$404.58	$396.98	$297.30	$2,241.71	$99.70	$77.24	$71.31	$71.31	$82.23	$115.29	$517.09	$2,758.80

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2010 - 2011																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3077	$23.08	$23.08	$23.08	$23.08	$23.08	$23.08	$138.47								
Over	75 units @	$0.2007	$23.68	$38.94	$44.76	$37.53	$31.91	$19.27	$196.08								
	COG 1	$1.1231	$216.76						$216.76								
	COG 2	$1.0980		$295.36					$295.36								
	COG 3	$1.1443			$341.00				$341.00								
	COG 4	$1.1859				$310.71			$310.71								
	COG 5	$1.1859					$277.50		$277.50								
	COG 6	$1.1859						$202.79	$202.79								
Winter Period 2010-2011 Avg. COG		$1.1539															
	LDAC	$ 0.0249	$4.81	$6.70	$7.42	$6.52	$5.83	$4.26	$35.53								
Summer 2011																	
Customer Charge	units @	$ 18.70								$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20	
First	75 units @	$0.3077								$23.08	$23.08	$22.15				$68.31	
First	75 units (Temp)	$0.3370											$24.26	$25.28	$25.28	$74.81	
Over	75 units @	$0.2007								$8.43	$1.20	$0.00				$9.63	
Over	75 units (Temp)	$0.2300											$0.00	$3.22	$15.41	$18.63	
	COG 1	$0.7234								$84.64						$84.64	
	COG 2	$0.7234									$58.60					$58.60	
	COG 3	$0.6553										$47.18				$47.18	
	COG 4	$0.7246											$52.17			$52.17	
	COG 5	$0.6131												$54.57		$54.57	
	COG 6	$0.6131													$87.06	$87.06	
Summer Period 2011 Avg. COG		$0.6755															
	LDAC	$ 0.0249								$2.91	$2.02	$1.79	$1.79	$2.22	$3.54	$14.27	
	TOTAL		$287.02	$382.77	$434.96	$396.54	$357.02	$268.09	$2,126.40	$137.76	$103.59	$89.83	$96.93	$103.98	$149.98	$682.07	$2,808.47
	Change		$4.09	$12.45	$21.55	$8.04	$39.97	$29.21	$115.31	($38.06)	($26.35)	($18.52)	($25.62)	($21.74)	($34.69)	**($164.98)**	($49.67)
	% Chg		1.43%	3.25%	4.95%	2.03%	11.19%	10.89%	5.42%	-27.63%	-25.44%	-20.62%	-26.43%	-20.91%	-23.13%	**-24.19%**	-1.77%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2012 vs. Summer 2011

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2011 - 2012																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.2235	$347.10	$576.18	$729.73	$917.02	$760.35	$552.72	$3,883.09								
	COG 1	$1.1166	$1,734.08						$1,734.08								
	COG 2	$1.1166		$2,878.59					$2,878.59								
	COG 3	$1.1889			$3,881.76				$3,881.76								
	COG 4	$1.1889				$4,878.06			$4,878.06								
	COG 5	$1.3290					$4,521.26		$4,521.26								
	COG 6	$1.3290						$3,286.62	$3,286.62								
Winter Period 2011-2012 Avg. COG		$1.2115															
	LDAC	$0.0233	$36.18	$60.07	$76.07	$95.60	$79.27	$57.62	$404.81								
Summer 2012																	
Customer Charge	units @	$ 60.30								$ 60.30	$60.30	$60.30	$60.30	$ 60.30	$60.30	$361.80	
All	units @	$0.1417								$178.26	$99.33	$58.66	$30.18	$51.58	$99.05	$517.06	
	COG 1	$0.3704								$465.96						$465.96	
	COG 2	$0.3704									$259.65					$259.65	
	COG 3	$0.3704										$153.35				$153.35	
	COG 4	$0.3704											$78.90			$78.90	
	COG 5	$0.3704												$134.83		$134.83	
	COG 6	$0.3704													$258.91	$258.91	
Summer Period 2012 Avg. COG		$0.3704															
	LDAC	$ 0.0233								$29.31	$16.33	$9.65	$4.96	$8.48	$16.29	$85.02	
	TOTAL		$2,177.66	$3,575.15	$4,747.86	$5,950.98	$5,421.17	$3,957.25	$25,830.07	$733.83	$435.62	$281.96	$174.34	$255.19	$434.54	$2,315.47	$28,145.54

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2010 - 2011																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.1942	$301.59	$500.65	$634.06	$796.80	$660.67	$480.26	$3,374.03								
	COG 1	$1.1231	$1,744.17						$1,744.17								
	COG 2	$1.0980		$2,830.64					$2,830.64								
	COG 3	$1.1443			$3,736.14				$3,736.14								
	COG 4	$1.1859				$4,865.75			$4,865.75								
	COG 5	$1.1859					$4,034.43		$4,034.43								
	COG 6	$1.1859						$2,932.73	$2,932.73								
Winter Period 2010-2011 Avg. COG		$1.1539															
	LDAC	$ 0.0249	$38.67	$64.19	$81.30	$102.16	$84.71	$61.58	$432.61								
Summer 2011																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
All	units @	$0.1124								$141.40	$78.79	$46.53				$266.73	
All	units (Temp)	$0.1417											$30.18	$51.58	$99.05	$180.81	
	COG 1	$0.7234								$910.04						$910.04	
	COG 2	$0.7234									$507.10					$507.10	
	COG 3	$0.6553										$271.29				$271.29	
	COG 4	$0.7246											$154.34			$154.34	
	COG 5	$0.6131												$223.17		$223.17	
	COG 6	$0.6131													$428.56	$428.56	
Summer Period 2011 Avg. COG		$0.6755															
	LDAC	$ 0.0249								$31.32	$17.45	$10.31	$5.30	$9.06	$17.41	$90.86	
	TOTAL		$2,144.74	$3,455.78	$4,511.80	$5,825.02	$4,840.11	$3,534.87	$24,312.31	$1,143.06	$663.65	$388.44	$250.13	$344.11	$605.31	$3,394.69	$27,707.01
	Change		$32.92	$119.36	$236.06	$125.96	$581.06	$422.39	$1,517.76	($409.23)	($228.04)	($106.48)	($75.79)	($88.93)	($170.77)	**($1,079.22)**	$438.54
	% Chg		1.54%	3.45%	5.23%	2.16%	12.01%	11.95%	6.24%	-35.80%	-34.36%	-27.41%	-30.30%	-25.84%	-28.21%	**-31.79%**	1.58%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2012 vs. Summer 2011

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2011 - 2012																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.2155	$280.15	$280.15	$280.15	$280.15	$280.15	$280.15	$1,680.90								
Over	1,300 units @	$0.1760	$74.27	$138.34	$181.28	$181.81	$174.42	$100.67	$850.78								
	COG 1	$0.9232	$1,589.75						$1,589.75								
	COG 2	$0.9232		$1,925.80					$1,925.80								
	COG 3	$0.9955			$2,319.52				$2,319.52								
	COG 4	$0.9955				$2,322.50			$2,322.50								
	COG 5	$1.1356					$2,601.66		$2,601.66								
	COG 6	$1.1356						$2,125.84	$2,125.84								
Winter Period 2011-2012 Avg. COG		$1.0181															
	LDAC	$0.0233	$40.12	$48.60	$54.29	$54.36	$53.38	$43.62	$294.37								
Summer 2012																	
Customer Charge	units @	$ 60.30								$ 60.30	$60.30	$60.30	$60.30	$ 60.30	$60.30	$361.80	
First	1,000 units @	$0.1405								$140.50	$140.50	$140.50	$140.50	$140.50	$140.50	$843.00	
Over	1,000 units @	$0.1073								$54.72	$40.13	$26.50	$20.39	$22.53	$34.77	$199.04	
	COG 1	$0.2942								$444.24						$444.24	
	COG 2	$0.2942									$404.23					$404.23	
	COG 3	$0.2942										$366.87				$366.87	
	COG 4	$0.2942											$350.10			$350.10	
	COG 5	$0.2942												$355.98		$355.98	
	COG 6	$0.2942													$389.52	$389.52	
Summer Period 2012 Avg. COG		$0.2942															
	LDAC	$ 0.0233								$35.18	$32.01	$29.06	$27.73	$28.19	$30.85	$183.02	
		TOTAL	$2,044.60	$2,453.19	$2,895.53	$2,899.12	$3,169.91	$2,610.58	$16,072.92	$734.95	$677.18	$623.23	$599.01	$607.51	$655.94	$3,897.80	$19,970.73

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2010 - 2011																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.1862	$242.06	$242.06	$242.06	$242.06	$242.06	$242.06	$1,452.36								
Over	1,300 units @	$0.1467	$61.91	$115.31	$151.10	$151.54	$145.38	$83.91	$709.15								
	COG 1	$0.9702	$1,670.68						$1,670.68								
	COG 2	$0.9451		$1,971.48					$1,971.48								
	COG 3	$0.9914			$2,309.96				$2,309.96								
	COG 4	$1.0330				$2,409.99			$2,409.99								
	COG 5	$1.0330					$2,366.60		$2,366.60								
	COG 6	$1.0330						$1,933.78	$1,933.78								
Winter Period 2010-2011 Avg. COG		$1.0010															
	LDAC	$ 0.0249	$42.88	$51.94	$58.02	$58.09	$57.05	$46.61	$314.59								
Summer 2011																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
First	1,000 units @	$0.1112								$111.20	$111.20	$111.20				$333.60	
First	1,000 Units (Temp)	$0.1405											$140.50	$140.50	$140.50	$421.50	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27				$88.22	
Over	1,000 Units (Temp)	$0.1073											$20.39	$22.53	$34.77	$77.69	
	COG 1	$0.5975								$902.23						$902.23	
	COG 2	$0.5975									$820.97					$820.97	
	COG 3	$0.5294										$660.16				$660.16	
	COG 4	$0.5987											$712.45			$712.45	
	COG 5	$0.4872												$589.51		$589.51	
	COG 6	$0.4872													$645.05	$645.05	
Summer Period 2011 Avg. COG		$0.5496															
	LDAC	$ 0.0249								$37.60	$34.21	$31.05	$29.63	$30.13	$32.97	$195.59	
		TOTAL	$2,077.83	$2,441.09	$2,821.44	$2,921.98	$2,871.39	$2,366.66	$15,500.39	$1,151.10	$1,055.85	$881.98	$963.27	$842.97	$913.59	$5,808.76	$21,309.15
		Change	($33.23)	$12.10	$74.09	($22.86)	$298.52	$243.92	$572.53	($416.16)	($378.67)	($258.75)	($364.26)	($235.47)	($257.65)	**($1,910.96)**	($1,338.42)
		% Chg	-1.60%	0.50%	2.63%	-0.78%	10.40%	10.31%	3.69%	-36.15%	-35.86%	-29.34%	-37.81%	-27.93%	-28.20%	**-32.90%**	-6.28%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2012 vs. Actual Summer 2011

Residential Heating

	Summer 2011	Summer 2012
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4249	$0.4395
Over 50 therms	$0.3137	$0.3283
LDAC	$0.0456	$0.0440
CGA	$0.6194	$0.3371

	Usage (Therms)	Summer 2011 Bill Amount	Summer 2012 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$14.95	$13.60	($1.35)	-9.0%	$0.07	0.5%	($1.41)	-9.4%	($0.01)	-0.1%
	10	$20.40	$17.71	($2.69)	-13.2%	$0.15	0.7%	($2.82)	-13.8%	($0.02)	-0.1%
	20	$31.30	$25.91	($5.39)	-17.2%	$0.29	0.9%	($5.65)	-18.1%	($0.03)	-0.1%
	25	$36.75	$30.02	($6.73)	-18.3%	$0.37	1.0%	($7.06)	-19.2%	($0.04)	-0.1%
	30	$42.20	$34.12	($8.08)	-19.1%	$0.44	1.0%	($8.47)	-20.1%	($0.05)	-0.1%
	45	$58.54	$46.43	($12.12)	-20.7%	$0.66	1.1%	($12.70)	-21.7%	($0.07)	-0.1%
Average Monthly	50	$63.99	$50.53	($13.46)	-21.0%	$0.73	1.1%	($14.11)	-22.0%	($0.08)	-0.1%
	75	$88.46	$68.27	($20.20)	-22.8%	$1.10	1.2%	($21.17)	-23.9%	($0.12)	-0.1%
	125	$137.40	$103.74	($33.66)	-24.5%	$1.83	1.3%	($35.29)	-25.7%	($0.20)	-0.1%
	150	$161.86	$121.47	($40.39)	-25.0%	$2.19	1.4%	($42.34)	-26.2%	($0.24)	-0.1%
	200	$210.80	$156.94	($53.86)	-25.5%	$2.92	1.4%	($56.46)	-26.8%	($0.32)	-0.2%

Schedule 9

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

		2011 Summer (6 months actual)			Forecast Summer 2012 (6 months proposed)			Variance		
1	Therm Sales	6,353,410			7,466,573			1,113,163		
2				EFFECT			EFFECT			EFFECT
3		THERM		ON COST	THERM		ON COST	THERM		ON COST
4		SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS
5										
6	Demand Charges		$1,227,460	$ 0.1932		$ 858,736	$ 0.1150		$ (368,724)	$(0.0782)
7										
8	Purchased Gas		2,805,960	0.4416		1,495,238	0.2003		$(1,310,722)	$(0.2414)
9										
10	Storage & Peaking Gas		27,028	0.0043		21,944	0.0029		$ (5,084)	$(0.0013)
11										
12	Hedging (Gain)/Loss		95,463	0.0150		171,582	0.0230		76,119	0.0080
13										
14										
15	Total Volumes and Cost	$ -	$4,155,911	$ 0.6541	$ -	$2,547,501	$ 0.3412	$ -	$(1,608,410)	$(0.3129)
16										
17	Prior Period Balance		$124,276	$ 0.0196		$ (151,792)	$(0.0203)		$ (276,068)	$(0.0399)
18						$ -	$ -		$ -	$ -
19	Interest		$ 9,684	$ 0.0015		(2,889)	$(0.0004)		(12,573)	$(0.0019)
20	Refunds from Suppliers		-	$ -		-	$ -		-	$ -
21										
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
24	Capacity Release									
25	Working Capital Allowance		(978)	$(0.0002)		1,120	$ 0.0002		2,098	$ 0.0003
26	Bad Debt Allowance		(1,497)	$(0.0002)		$ 37,571	$ 0.0050		39,068	$ 0.0053
27	Fuel Inventory Financing									
28	Local Production and Storage					-	$ -		-	$ -
29	Misc Overhead		25,964	$ 0.0041		85,176	$ 0.0114		59,212	$ 0.0073
30										
31	Total Anticipated Indirect Cost of Gas		$157,449	$ 0.0248		(30,813)	$(0.0041)		(188,262)	$(0.0289)
32	Total Adjusted Cost	-	4,313,360	$ 0.6789		2,516,688	$ 0.3370		(1,796,672)	$(0.3419)

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

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

Base Capacity Costs

	BASE SENDOUT BY CLASS	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
2	**Total Therms**									
3	Res Heat	478,412	462,979	474,262	478,412	462,979	478,412	5,644,196	2,835,456	Schedule 10B, LN 52
4	Res General	17,566	17,000	17,414	17,566	17,000	17,566	207,242	104,112	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	106,331	102,901	105,409	106,331	102,901	106,331	1,254,473	630,205	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	136,324	131,927	135,142	136,324	131,927	136,324	1,608,324	807,968	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	142,185	137,598	140,951	142,185	137,598	142,185	1,677,463	842,702	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	169,435	163,970	167,966	169,435	163,970	169,435	1,998,961	1,004,211	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	6,005	5,811	6,001	6,005	5,811	6,005	70,892	35,638	Schedule 10B, LN 58
10	G42 High Annual-High Winter	20,896	20,222	20,715	20,896	20,222	20,896	246,532	123,849	Schedule 10B, LN 59
11	Total Firm Sales	1,077,155	1,042,408	1,067,860	1,077,155	1,042,408	1,077,155	12,708,083	6,384,141	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	44.41%	44.41%	44.41%	44.41%	44.41%	44.41%			LN 3 / LN 11
15	Res General	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%			LN 5 / LN 11
17	G40 Low Annual-High Winter	12.66%	12.66%	12.66%	12.66%	12.66%	12.66%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%			LN 7 / LN 11
19	G41 Med Annual-High Winter	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%			LN 8 / LN 11
20	G52 High Annual-Low Winter	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%			LN 9 / LN 11
21	G42 High Annual-High Winter	1.94%	1.94%	1.94%	1.94%	1.94%	1.94%			LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			LN 11 / LN 11
23										
24	**PIPELINE BASE DEMAND COSTS**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 71,359	$ 71,359	$ 71,359	$ 71,359	$ 71,359	$ 71,359	$ 856,305	$ 428,153	Schedule 1A, LN 69
26	Res Heat	$ 31,694	$ 31,694	$ 31,692	$ 31,694	$ 31,694	$ 31,694	$ 380,321	$ 190,160	LN 25 * LN 14
27	Res General	$ 1,164	$ 1,164	$ 1,164	$ 1,164	$ 1,164	$ 1,164	$ 13,965	$ 6,982	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,044	$ 7,044	$ 7,044	$ 7,044	$ 7,044	$ 7,044	$ 84,530	$ 42,265	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 9,031	$ 9,031	$ 9,031	$ 9,031	$ 9,031	$ 9,031	$ 108,373	$ 54,186	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 9,419	$ 9,419	$ 9,419	$ 9,419	$ 9,419	$ 9,419	$ 113,032	$ 56,516	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 11,225	$ 11,225	$ 11,224	$ 11,225	$ 11,225	$ 11,225	$ 134,695	$ 67,347	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 398	$ 398	$ 401	$ 398	$ 398	$ 398	$ 4,777	$ 2,390	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,384	$ 1,384	$ 1,384	$ 1,384	$ 1,384	$ 1,384	$ 16,612	$ 8,306	LN 25 * LN 21
34										
35	Residential	$ 32,857	$ 32,857	$ 32,856	$ 32,857	$ 32,857	$ 32,857	$ 394,286	$ 197,142	LN 26 + LN 27
36	SALES HLF CLASSES	$ 16,861	$ 16,861	$ 16,864	$ 16,861	$ 16,861	$ 16,861	$ 202,339	$ 101,171	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 21,640	$ 21,640	$ 21,639	$ 21,640	$ 21,640	$ 21,640	$ 259,681	$ 129,840	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

LN		Column A Design Day Demand (MMBtu)	Column B Avg Daily Base Use Load (MMBtu)	Column C Remaining Design Day Demand (MMBtu)	Column D % of Total Remaining Design Day Demand	
39						
40	Res Heat	17,799	1,528	16,271	45.34%	Company Analysis
41	Res General	276	56	220	0.61%	Company Analysis
42	G50 Low Annual-Low Winter	1,221	340	882	2.46%	Company Analysis
43	G40 Low Annual-High Winter	9,679	435	9,243	25.76%	Company Analysis
44	G51 Med Annual-Low Winter	1,726	454	1,272	3.54%	Company Analysis
45	G41 Med Annual-High Winter	7,525	541	6,984	19.46%	Company Analysis
46	G52 High Annual-Low Winter	47	19	28	0.08%	Company Analysis
47	G42 High Annual-High Winter	1,051	67	984	2.74%	Company Analysis
48	TOTAL	39,324	3,440	35,884	100.00%	Sum LN 40 : LN 47
49						

50 **REMAINING PIPELINE DEMAND**

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
51		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 12,313	$ 1,913	$ -	$ 317	$ 5,382	$ 33,497	$ 1,934,960	$ 53,421	Schedule 1A, LN 70
53										
54	Res Heat	$ 5,583	$ 867	$ -	$ 144	$ 2,440	$ 15,189	$ 877,402	$ 24,224	LN 40 Col D * LN 52
55	Res General	$ 75	$ 12	$ -	$ 2	$ 33	$ 205	$ 11,855	$ 327	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 303	$ 47	$ -	$ 8	$ 132	$ 823	$ 47,553	$ 1,313	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 3,172	$ 493	$ -	$ 82	$ 1,386	$ 8,629	$ 498,434	$ 13,761	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 436	$ 68	$ -	$ 11	$ 191	$ 1,187	$ 68,585	$ 1,894	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 2,396	$ 372	$ -	$ 62	$ 1,047	$ 6,519	$ 376,574	$ 10,397	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 9	$ 1	$ -	$ 0	$ 4	$ 26	$ 1,493	$ 41	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 338	$ 52	$ -	$ 9	$ 148	$ 919	$ 53,063	$ 1,465	LN 47 Col D * LN 52
62	TOTAL	$ 12,313	$ 1,913	$ -	$ 317	$ 5,382	$ 33,497	$ 1,934,960	$ 53,421	Sum LN 54 : LN 61
63										
64	Residential	$ 5,659	$ 879	$ -	$ 146	$ 2,473	$ 15,394	$ 889,257	$ 24,551	LN 54 + LN 55
65	SALES HLF CLASSES	$ 749	$ 116	$ -	$ 19	$ 327	$ 2,036	$ 117,631	$ 3,248	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 5,906	$ 917	$ -	$ 152	$ 2,581	$ 16,066	$ 928,072	$ 25,623	LN 57 + LN 59 + LN 61
67										

68 **PEAKING AND STORAGE DEMAND**

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
69		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 86,930	$ 13,504	$ -	$ 2,239	$ 37,996	$ 236,492	$ 13,661,065	$ 377,162	Schedule 1A, LN 73
71										
72	Res Heat	$ 39,418	$ 6,123	$ -	$ 1,015	$ 17,229	$ 107,237	$ 6,194,569	$ 171,023	LN 40 Col D * LN 70
73	Res General	$ 533	$ 83	$ -	$ 14	$ 233	$ 1,449	$ 83,701	$ 2,311	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 2,136	$ 332	$ -	$ 55	$ 934	$ 5,812	$ 335,731	$ 9,269	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 22,393	$ 3,479	$ -	$ 577	$ 9,788	$ 60,919	$ 3,519,012	$ 97,155	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 3,081	$ 479	$ -	$ 79	$ 1,347	$ 8,382	$ 484,217	$ 13,369	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 16,918	$ 2,628	$ -	$ 436	$ 7,395	$ 46,025	$ 2,658,663	$ 73,402	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 67	$ 10	$ -	$ 2	$ 29	$ 182	$ 10,539	$ 291	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 2,384	$ 370	$ -	$ 61	$ 1,042	$ 6,485	$ 374,634	$ 10,343	LN 47 Col D * LN 70
80	TOTAL	$ 86,930	$ 13,504	$ -	$ 2,239	$ 37,996	$ 236,492	$ 13,661,065	$ 377,162	Sum LN 72 : LN 79
81										
82	Residential	$ 39,951	$ 6,206	$ -	$ 1,029	$ 17,462	$ 108,686	$ 6,278,269	$ 173,334	LN 72 + LN 73
83	SALES HLF CLASSES	$ 5,285	$ 821	$ -	$ 136	$ 2,310	$ 14,377	$ 830,487	$ 22,929	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 41,695	$ 6,477	$ -	$ 1,074	$ 18,224	$ 113,430	$ 6,552,308	$ 180,900	LN 75 + LN 77 + LN 79
85										

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

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
87										
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,405,780)	$ -	Schedule 1A, LN 76
89										
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,090,894)	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,740)	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (59,124)	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (619,715)	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,273)	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (468,204)	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,856)	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (65,975)	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,405,780)	$ -	Sum LN 90 : LN 97
99										
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,105,634)	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (146,253)	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,153,893)	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
105										
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107										
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117										
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
123		**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**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**

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
141		**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**SUMMER**	
142	Res Heat	$ 45,002	$ 6,991	$ -	$ 1,159	$ 19,670	$ 122,426	$ 5,981,077	$ 195,247	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 608	$ 94	$ -	$ 16	$ 266	$ 1,654	$ 80,816	$ 2,638	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 2,439	$ 379	$ -	$ 63	$ 1,066	$ 6,635	$ 324,160	$ 10,582	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 25,565	$ 3,971	$ -	$ 659	$ 11,174	$ 69,548	$ 3,397,731	$ 110,916	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 3,518	$ 546	$ -	$ 91	$ 1,538	$ 9,570	$ 467,529	$ 15,262	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 19,314	$ 3,000	$ -	$ 498	$ 8,442	$ 52,544	$ 2,567,034	$ 83,798	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 77	$ 12	$ -	$ 2	$ 33	$ 208	$ 10,176	$ 332	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 2,722	$ 423	$ -	$ 70	$ 1,190	$ 7,404	$ 361,722	$ 11,808	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 99,243	$ 15,417	$ -	$ 2,556	$ 43,378	$ 269,989	$ 13,190,244	$ 430,583	Sum LN 142 : LN 149
151										
152	Residential	$ 45,610	$ 7,085	$ -	$ 1,175	$ 19,935	$ 124,080	$ 6,061,893	$ 197,885	LN 142 + LN 143
153	SALES HLF CLASSES	$ 6,033	$ 937	$ -	$ 155	$ 2,637	$ 16,413	$ 801,865	$ 26,176	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 47,600	$ 7,394	$ -	$ 1,226	$ 20,806	$ 129,496	$ 6,326,487	$ 206,522	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER	
157		**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**SUMMER**	
158	Res Heat	$ 76,695	$ 38,684	$ 31,692	$ 32,853	$ 51,363	$ 154,119	$ 6,361,398	$ 385,407	LN 142 + LN 26
159	Res General	$ 1,772	$ 1,258	$ 1,164	$ 1,179	$ 1,429	$ 2,818	$ 94,781	$ 9,620	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 9,483	$ 7,423	$ 7,044	$ 7,107	$ 8,110	$ 13,679	$ 408,690	$ 52,847	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 34,596	$ 13,002	$ 9,031	$ 9,690	$ 20,205	$ 78,579	$ 3,506,104	$ 165,102	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 12,937	$ 9,966	$ 9,419	$ 9,510	$ 10,957	$ 18,989	$ 580,561	$ 71,778	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 30,539	$ 14,225	$ 11,224	$ 11,722	$ 19,667	$ 63,769	$ 2,701,729	$ 151,146	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 474	$ 410	$ 401	$ 400	$ 431	$ 606	$ 14,953	$ 2,722	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 4,106	$ 1,807	$ 1,384	$ 1,454	$ 2,574	$ 8,788	$ 378,334	$ 20,114	LN 149 + LN 33
166	TOTAL	$ 170,602	$ 86,775	$ 71,359	$ 73,915	$ 114,737	$ 341,348	$ 14,046,550	$ 858,736	Sum LN 158 : LN 165
167										
168	Residential	$ 78,467	$ 39,942	$ 32,856	$ 34,032	$ 52,793	$ 156,937	$ 6,456,178	$ 395,027	LN 158 + LN 159
169	SALES HLF CLASSES	$ 22,895	$ 17,799	$ 16,864	$ 17,017	$ 19,498	$ 33,275	$ 1,004,204	$ 127,347	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 69,241	$ 29,034	$ 21,639	$ 22,866	$ 42,446	$ 151,136	$ 6,586,168	$ 336,362	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								27%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								73%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2011 - 2012 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Normal Winter	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	SUMMER
1	Res Heat	598,377	481,043	469,565	477,796	518,017	773,384	16,637,146	3,318,182
2	Res General	21,971	17,663	17,241	17,544	19,020	28,397	335,046	121,836
3	**Total Residential**	**620,349**	**498,705**	**486,807**	**495,340**	**537,038**	**801,781**	**16,972,192**	**3,440,019**
4	G50 Low Annual-Low Winter	132,995	106,916	104,365	106,194	115,134	171,891	1,807,855	737,496
5	G40 Low Annual-High Winter	170,509	137,074	133,803	136,149	147,610	220,377	7,309,393	945,522
6	G51 Med Annual-Low Winter	177,839	142,967	139,555	142,002	153,955	229,851	2,417,366	986,169
7	G41 Med Annual-High Winter	211,923	170,367	166,302	169,217	183,462	273,903	6,557,356	1,175,175
8	G52 High Annual-Low Winter	6,742	6,320	5,941	5,950	5,973	6,333	91,057	37,259
9	G42 High Annual-High Winter	26,136	21,011	20,510	20,870	22,626	33,780	925,811	144,934
10	**Total C&I**	**726,143**	**584,655**	**570,478**	**580,382**	**628,761**	**936,136**	**19,108,838**	**4,026,554**
11	**Total Sales**	**1,346,492**	**1,083,360**	**1,057,284**	**1,075,722**	**1,165,799**	**1,737,916**	**36,081,030**	**7,466,573**
12									
13	Residential Heat & Non Heat	620,349	498,705	486,807	495,340	537,038	801,781	16,972,192	3,440,019
14	SALES HLF CLASSES	317,576	256,202	249,862	254,146	275,062	408,075	4,316,278	1,760,923
15	SALES LLF CLASSES	408,568	328,452	320,616	326,236	353,698	528,061	14,792,560	2,265,631
16	**Total Firm Sales**	**1,346,492**	**1,083,360**	**1,057,284**	**1,075,722**	**1,165,799**	**1,737,916**	**36,081,030**	**7,466,573**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**SUMMER**
21	Res Heat	604,318	485,860	474,262	482,561	523,168	780,950	16,796,533	3,351,120
22	Res General	22,189	17,840	17,414	17,719	19,210	28,675	338,280	123,046
23	G50 Low Annual-Low Winter	134,315	107,987	105,409	107,254	116,279	173,573	1,825,338	744,816
24	G40 Low Annual-High Winter	172,202	138,447	135,142	137,507	149,078	222,533	7,379,196	954,908
25	G51 Med Annual-Low Winter	179,604	144,398	140,951	143,418	155,486	232,100	2,440,742	995,958
26	G41 Med Annual-High Winter	214,027	172,073	167,966	170,905	185,286	276,583	6,620,119	1,186,840
27	G52 High Annual-Low Winter	6,809	6,383	6,001	6,009	6,032	6,394	91,939	37,629
28	G42 High Annual-High Winter	26,396	21,222	20,715	21,078	22,851	34,111	934,663	146,373
29	**Subtotal**								
30	Residential	626,507	503,700	491,676	500,280	542,377	809,625	17,134,812	3,474,166
31	SALES HLF CLASSES	320,728	258,768	252,361	256,681	277,797	412,067	4,358,019	1,778,403
32	SALES LLF CLASSES	412,624	331,742	323,823	329,489	357,215	533,227	14,933,979	2,288,121
33	**Total Firm Sales**	1,359,860	1,094,210	1,067,860	1,086,450	1,177,390	1,754,920	36,426,810	7,540,690

Northern Utilities - NEW HAMPSHIRE DIVISION
2011 - 2012 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes	
	Firm Sales	
1	Res Heat	Company Analysis
2	Res General	Company Analysis
3	**Total Residential**	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	Company Analysis
5	G40 Low Annual-High Winter	Company Analysis
6	G51 Med Annual-Low Winter	Company Analysis
7	G41 Med Annual-High Winter	Company Analysis
8	G52 High Annual-Low Winter	Company Analysis
9	G42 High Annual-High Winter	Company Analysis
10	**Total C&I**	Sum LN 4 : LN 9
11	**Total Sales**	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	**Total Firm Sales**	Sum LN 13 : LN 15
17		
18	**ESTIMATED SENDOUT BY CLASS - Therms**	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Company Use, LAUF, BTU) x 10
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU) x 10
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU) x 10
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU) x 10
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU) x 10
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU) x 10
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU) x 10
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU) x 10
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

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

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

BASE SENDOUT BY CLASS - Therms								
Days per Month	31	30	31	31	30	31		
	May-12	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**SUMMER**
Res Heat	478,412	462,979	474,262	478,412	462,979	478,412	5,644,196	2,835,456
Res General	17,566	17,000	17,414	17,566	17,000	17,566	207,242	104,112
G50 Low Annual-Low Winter	106,331	102,901	105,409	106,331	102,901	106,331	1,254,473	630,205
G40 Low Annual-High Winter	136,324	131,927	135,142	136,324	131,927	136,324	1,608,324	807,968
G51 Med Annual-Low Winter	142,185	137,598	140,951	142,185	137,598	142,185	1,677,463	842,702
G41 Med Annual-High Winter	169,435	163,970	167,966	169,435	163,970	169,435	1,998,961	1,004,211
G52 High Annual-Low Winter	6,005	5,811	6,001	6,005	5,811	6,005	70,892	35,638
G42 High Annual-High Winter	20,896	20,222	20,715	20,896	20,222	20,896	246,532	123,849
Subtotal								
Residential	495,978	479,979	491,676	495,978	479,979	495,978	5,851,438	2,939,567
SALES HLF CLASSES	254,521	246,311	252,361	254,521	246,311	254,521	3,002,829	1,508,545
SALES LLF CLASSES	326,656	316,119	323,823	326,656	316,119	326,656	3,853,817	1,936,029
Total Firm Sales	1,077,155	1,042,408	1,067,860	1,077,155	1,042,408	1,077,155	12,708,083	6,384,141

REMAINING SENDOUT BY CLASS - Therms								
	May-12	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**SUMMER**
Res Heat	125,906	22,881	-	4,150	60,189	302,539	11,152,337	515,664
Res General	4,623	840	-	152	2,210	11,109	131,037	18,934
G50 Low Annual-Low Winter	27,984	5,086	-	922	13,377	67,242	570,865	114,611
G40 Low Annual-High Winter	35,877	6,520	-	1,182	17,151	86,209	5,770,873	146,939
G51 Med Annual-Low Winter	37,420	6,800	-	1,233	17,888	89,915	763,279	153,256
G41 Med Annual-High Winter	44,591	8,104	-	1,470	21,317	107,148	4,621,158	182,629
G52 High Annual-Low Winter	804	572	-	4	221	390	21,046	1,991
G42 High Annual-High Winter	5,499	999	-	181	2,629	13,215	688,132	22,524
Subtotal								
Residential	130,529	23,721	-	4,302	62,399	313,647	11,283,374	534,598
SALES HLF CLASSES	66,208	12,458	-	2,160	31,487	157,546	1,355,190	269,858
SALES LLF CLASSES	85,968	15,623	-	2,833	41,096	206,571	11,080,162	352,092
Total Firm Sales	282,705	51,802	-	9,295	134,982	677,765	23,718,727	1,156,549

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

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

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

	Total Division Metered Deliveries (Dth)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	493,457	455,056	38,402	8.4%	10,009	28,393	424,623	68,834	16.2%	12,997	55,837
Jun	376,206	340,672	35,534	10.4%	7,894	27,640	305,140	71,067	23.3%	8,724	62,343
Jul	305,376	277,859	27,517	9.9%	7,614	19,903	271,701	33,675	12.4%	9,498	24,176
Aug	283,044	277,161	5,883	2.1%	7,788	-1,905	283,312	-268	-0.1%	10,160	-10,428
Sep	301,907	305,657	-3,750	-1.2%	7,572	-11,322	294,853	7,054	2.4%	10,218	-3,164
Oct	365,582	403,626	-38,044	-9.4%	9,821	-47,865	375,541	-9,959	-2.7%	14,422	-24,381
Off-Peak	2,125,572	2,060,030	65,542	3.2%	51,409	14,133	1,955,169	170,403	8.7%	66,156	104,248

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

	Total Division Meter Counts						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	29,226	28,597	629	2.2%	28,358	868	3.1%
Jun	29,142	28,482	660	2.3%	28,332	810	2.9%
Jul	29,131	28,354	777	2.7%	28,147	984	3.5%
Aug	29,086	28,291	795	2.8%	28,079	1,007	3.6%
Sep	29,080	28,377	703	2.5%	28,106	974	3.5%
Oct	29,257	28,562	695	2.4%	28,175	1,082	3.8%
Off-Peak	29,154	28,444	710	2.5%	28,200	954	3.4%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	16.88	15.91	0.97	6.1%	14.97	1.91	12.8%
Jun	12.91	11.96	0.95	7.9%	10.77	2.14	19.9%
Jul	10.48	9.80	0.68	7.0%	9.65	0.83	8.6%
Aug	9.73	9.80	-0.07	-0.7%	10.09	-0.36	-3.6%
Sep	10.38	10.77	-0.39	-3.6%	10.49	-0.11	-1.0%
Oct	12.50	14.13	-1.64	-11.6%	13.33	-0.83	-6.3%
Off-Peak	72.91	72.42	0.48	0.7%	69.33	3.58	5.2%

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

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

	Residential Non-Heat Metered Deliveries (Dth)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	2,382	2,688	-306	-11.4%	-128	-177	2,575	-193	-7.5%	-166	-27
Jun	2,444	2,265	179	7.9%	-110	290	1,998	447	22.4%	-138	584
Jul	1,759	2,121	-362	-17.1%	-124	-238	1,877	-117	-6.2%	-139	22
Aug	1,844	1,684	160	9.5%	-102	262	1,674	169	10.1%	-126	296
Sep	1,817	1,901	-84	-4.4%	-118	34	1,915	-98	-5.1%	-142	44
Oct	1,937	2,045	-108	-5.3%	-129	21	1,920	17	0.9%	-156	173
Off-Peak	12,184	12,704	-520	-4.1%	-720	200	11,959	225	1.9%	-873	1,098

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

	Total Division Meter Counts						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1,577	1,656	-79	-4.8%	1,686	-109	-6.5%
Jun	1,582	1,663	-81	-4.9%	1,699	-117	-6.9%
Jul	1,563	1,660	-97	-5.8%	1,688	-125	-7.4%
Aug	1,556	1,656	-100	-6.0%	1,683	-127	-7.5%
Sep	1,537	1,639	-102	-6.2%	1,660	-123	-7.4%
Oct	1,503	1,604	-101	-6.3%	1,636	-133	-8.1%
Off-Peak	1,553	1,646	-93	-5.7%	1,675	-122	-7.3%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1.51	1.62	-0.11	-6.9%	1.53	-0.02	-1.1%
Jun	1.55	1.36	0.18	13.4%	1.18	0.37	31.4%
Jul	1.13	1.28	-0.15	-11.9%	1.11	0.01	1.2%
Aug	1.18	1.02	0.17	16.5%	0.99	0.19	19.1%
Sep	1.18	1.16	0.02	1.9%	1.15	0.03	2.5%
Oct	1.29	1.28	0.01	1.1%	1.17	0.12	9.8%
Off-Peak	7.85	7.72	0.13	1.7%	7.14	0.70	9.8%

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

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

	Residential Heat Metered Deliveries (Dth)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	112,759	98,041	14,719	15.0%	2,494	12,225	96,296	16,464	17.1%	3,576	12,887
Jun	67,629	57,942	9,687	16.7%	1,556	8,131	46,595	21,034	45.1%	1,632	19,402
Jul	38,202	37,861	341	0.9%	1,239	-898	35,665	2,537	7.1%	1,496	1,041
Aug	30,648	30,381	267	0.9%	1,012	-745	29,724	925	3.1%	1,266	-342
Sep	33,805	33,803	2	0.0%	1,071	-1,070	33,427	377	1.1%	1,405	-1,027
Oct	48,775	63,997	-15,222	-23.8%	1,957	-17,179	50,863	-2,088	-4.1%	2,370	-4,458
Off-Peak	331,818	322,025	9,794	3.0%	9,689	104	292,570	39,248	13.4%	11,960	27,288

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

	Total Division Meter Counts						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	21,167	20,642	525	2.5%	20,409	758	3.7%
Jun	21,104	20,552	552	2.7%	20,390	714	3.5%
Jul	21,117	20,448	669	3.3%	20,267	850	4.2%
Aug	21,093	20,413	680	3.3%	20,231	862	4.3%
Sep	21,127	20,478	649	3.2%	20,275	852	4.2%
Oct	21,268	20,637	631	3.1%	20,321	947	4.7%
Off-Peak	21,146	20,528	618	3.0%	20,316	831	4.1%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	5.33	4.75	0.58	12.2%	4.72	0.61	12.9%
Jun	3.20	2.82	0.39	13.7%	2.29	0.92	40.2%
Jul	1.81	1.85	-0.04	-2.3%	1.76	0.05	2.8%
Aug	1.45	1.49	-0.04	-2.4%	1.47	-0.02	-1.1%
Sep	1.60	1.65	-0.05	-3.1%	1.65	-0.05	-2.9%
Oct	2.29	3.10	-0.81	-26.0%	2.50	-0.21	-8.4%
Off-Peak	15.69	15.69	0.00	0.0%	14.40	1.30	9.0%

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

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

	Total Division C&I Metered Deliveries (Dth)										
	2011-2012	2011-2012 Compared to 2010-2011					2011-2012 Compared to 2009-2010				
	Forecast	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	378,316	354,327	23,989	6.8%	10,294	13,695	325,752	52,564	16.1%	11,391	41,173
Jun	306,133	280,465	25,668	9.2%	8,458	17,209	256,547	49,586	19.3%	8,753	40,833
Jul	265,414	237,876	27,538	11.6%	7,807	19,731	234,159	31,255	13.3%	9,794	21,461
Aug	250,552	245,096	5,456	2.2%	8,469	-3,013	251,914	-1,362	-0.5%	11,114	-12,476
Sep	266,286	269,953	-3,667	-1.4%	6,727	-10,395	259,511	6,775	2.6%	10,303	-3,528
Oct	314,870	337,584	-22,714	-6.7%	8,812	-31,526	322,758	-7,888	-2.4%	13,911	-21,799
Off-Peak	1,781,570	1,725,301	56,269	3.3%	51,050	5,218	1,650,640	130,930	7.9%	65,402	65,528

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

	Total Division Meter Counts						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	6,482	6,299	183	2.9%	6,263	219	3.5%
Jun	6,456	6,267	189	3.0%	6,243	213	3.4%
Jul	6,451	6,246	205	3.3%	6,192	259	4.2%
Aug	6,437	6,222	215	3.5%	6,165	272	4.4%
Sep	6,416	6,260	156	2.5%	6,171	245	4.0%
Oct	6,486	6,321	165	2.6%	6,218	268	4.3%
Off-Peak	6,455	6,269	186	3.0%	6,209	246	4.0%

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

	Total Division Use Per Meter						
	2011-2012	Compared to 2010-2011			Compared to 2009-2010		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	58.36	56.25	2.11	3.8%	52.01	6.35	12.2%
Jun	47.42	44.75	2.67	6.0%	41.09	6.32	15.4%
Jul	41.14	38.08	3.06	8.0%	37.82	3.33	8.8%
Aug	38.92	39.39	-0.47	-1.2%	40.86	-1.94	-4.7%
Sep	41.50	43.12	-1.62	-3.8%	42.05	-0.55	-1.3%
Oct	48.55	53.41	-4.86	-9.1%	51.91	-3.36	-6.5%
Off-Peak	276.01	275.20	0.81	0.3%	265.86	10.15	3.8%

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

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

Forecast Calendar Sales Service Usage (Dth)
(Forecast Billed Distribution Usage times Sales Service Percentage)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-12	2,197	59,838	17,051	13,299	21,192	17,784	2,614	674	0	134,649
Jun-12	1,766	48,104	13,707	10,692	17,037	14,297	2,101	632	0	108,336
Jul-12	1,724	46,957	13,380	10,437	16,630	13,956	2,051	594	0	105,728
Aug-12	1,754	47,780	13,615	10,619	16,922	14,200	2,087	595	0	107,572
Sep-12	1,902	51,802	14,761	11,513	18,346	15,396	2,263	597	0	116,580
Oct-12	2,840	77,338	22,038	17,189	27,390	22,985	3,378	633	0	173,792
Off-Peak	12,184	331,818	94,552	73,750	117,518	98,617	14,493	3,726	0	746,657

Forecast Calendar Distribution Service Usage (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-12	2,197	59,838	21,788	17,726	41,357	31,514	20,848	103,281	85,509	384,058
Jun-12	1,766	48,104	17,515	14,250	33,248	25,334	16,760	90,203	86,296	333,477
Jul-12	1,724	46,957	17,098	13,910	32,454	24,730	16,360	79,463	87,840	320,536
Aug-12	1,754	47,780	17,397	14,154	33,023	25,163	16,647	75,169	87,684	318,773
Sep-12	1,902	51,802	18,862	15,346	35,803	27,282	18,048	83,526	83,243	335,813
Oct-12	2,840	77,338	28,160	22,911	53,453	40,731	26,946	95,219	85,317	432,915
Off-Peak	12,184	331,818	120,820	98,298	229,338	174,754	115,610	526,861	515,889	2,125,572

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%
Jun-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	32%
Jul-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	33%
Aug-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	34%
Sep-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%
Oct-12	100%	100%	78%	75%	51%	56%	13%	1%	0%	40%
Off-Peak	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%

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

Forecast Billed Sales Service Usage (Dth)
(Forecast Billed Distribution Usage times Sales Service Percentage)

Month	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-12	2,382	112,759	40,530	13,253	35,341	17,702	4,827	674	0	227,468
Jun-12	2,444	67,629	17,831	12,577	25,382	16,807	1,680	632	0	144,983
Jul-12	1,759	38,202	8,193	11,791	12,456	15,769	1,596	594	0	90,361
Aug-12	1,844	30,648	6,959	11,781	10,895	15,762	1,433	595	0	79,918
Sep-12	1,817	33,805	7,985	11,818	12,771	15,812	2,072	597	0	86,677
Oct-12	1,937	48,775	13,054	12,529	20,673	16,765	2,885	633	0	117,250
Off-Peak	12,184	331,818	94,552	73,750	117,518	98,617	14,493	3,726	0	746,657

Forecast Billed Distribution Service Usage (Dth)

Month	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-12	2,382	112,759	47,638	18,001	64,799	32,600	26,488	103,281	85,509	493,457
Jun-12	2,444	67,629	22,228	16,744	44,166	29,826	16,670	90,203	86,296	376,206
Jul-12	1,759	38,202	11,682	15,486	27,415	27,247	16,282	79,463	87,840	305,376
Aug-12	1,844	30,648	9,587	15,297	22,091	26,625	14,098	75,169	87,684	283,044
Sep-12	1,817	33,805	11,461	15,747	27,234	27,901	17,174	83,526	83,243	301,907
Oct-12	1,937	48,775	18,224	17,023	43,634	30,554	24,899	95,219	85,317	365,582
Off-Peak	12,184	331,818	120,820	98,298	229,338	174,754	115,610	526,861	515,889	2,125,572

Forecast Sales Service Percentage

Month	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-12	100%	100%	85%	74%	55%	54%	18%	1%	0%	46%
Jun-12	100%	100%	80%	75%	57%	56%	10%	1%	0%	39%
Jul-12	100%	100%	70%	76%	45%	58%	10%	1%	0%	30%
Aug-12	100%	100%	73%	77%	49%	59%	10%	1%	0%	28%
Sep-12	100%	100%	70%	75%	47%	57%	12%	1%	0%	29%
Oct-12	100%	100%	72%	74%	47%	55%	12%	1%	0%	32%
Off-Peak	100%	100%	78%	75%	51%	56%	13%	1%	0%	35%

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

Month	Calendar Month Distribution Service Usage (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Billed Sales Service Deliveries (Dth)	Unbilled Sales Service Deliveries (Dth)	Calendar Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Lost and Unaccounted For (Percent)	Lost and Unaccounted For (Dth)	Estimated Division City-Gate Receipts (Dth)
May-12	384,058	0.04%	154	227,468	-92,819	134,649	134,803	0.87%	1,183	135,986
Jun-12	333,477	0.04%	133	144,983	-36,647	108,336	108,469	0.87%	952	109,421
Jul-12	320,536	0.04%	128	90,361	15,367	105,728	105,857	0.87%	929	106,786
Aug-12	318,773	0.04%	128	79,918	27,654	107,572	107,700	0.87%	945	108,645
Sep-12	335,813	0.04%	134	86,677	29,903	116,580	116,714	0.87%	1,025	117,739
Oct-12	432,915	0.04%	173	117,250	56,541	173,792	173,965	0.87%	1,527	175,492
Off-Peak	2,125,572	0.04%	850	746,657	0	746,657	747,508	0.87%	6,561	754,069

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
2	**Total Therms**								
3	Res Heat	478,412	462,979	474,262	478,412	462,979	478,412	5,644,196	2,835,456
4	Res General	17,566	17,000	17,414	17,566	17,000	17,566	207,242	104,112
5	G50 Low Annual-Low Winter	106,331	102,901	105,409	106,331	102,901	106,331	1,254,473	630,205
6	G40 Low Annual-High Winter	136,324	131,927	135,142	136,324	131,927	136,324	1,608,324	807,968
7	G51 Med Annual-Low Winter	142,185	137,598	140,951	142,185	137,598	142,185	1,677,463	842,702
8	G41 Med Annual-High Winter	169,435	163,970	167,966	169,435	163,970	169,435	1,998,961	1,004,211
9	G52 High Annual-Low Winter	6,005	5,811	6,001	6,005	5,811	6,005	70,892	35,638
10	G42 High Annual-High Winter	20,896	20,222	20,715	20,896	20,222	20,896	246,532	123,849
11	Total Firm Sales	1,077,155	1,042,408	1,067,860	1,077,155	1,042,408	1,077,155	12,708,083	6,384,141
12	**% of Total**								
13	Res Heat	44.41%	44.41%	44.41%	44.41%	44.41%	44.41%		
14	Res General	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%		
15	G50 Low Annual-Low Winter	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%		
16	G40 Low Annual-High Winter	12.66%	12.66%	12.66%	12.66%	12.66%	12.66%		
17	G51 Med Annual-Low Winter	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%		
18	G41 Med Annual-High Winter	15.73%	15.73%	15.73%	15.73%	15.73%	15.73%		
19	G52 High Annual-Low Winter	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%		
20	G42 High Annual-High Winter	1.94%	1.94%	1.94%	1.94%	1.94%	1.94%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
23	TOTAL BASE COMMODITY Excld Hedging	$ 190,464	$ 198,461	$ 212,995	$ 219,756	$ 215,264	$ 231,590	$ 4,987,902	$ 1,268,531
24	Res Heat	$ 84,594	$ 88,145	$ 94,596	$ 97,603	$ 95,608	$ 102,859	$ 2,215,342	$ 563,406
25	Res General	$ 3,106	$ 3,237	$ 3,473	$ 3,584	$ 3,511	$ 3,777	$ 81,342	$ 20,687
26	G50 Low Annual-Low Winter	$ 18,802	$ 19,591	$ 21,025	$ 21,693	$ 21,250	$ 22,861	$ 492,380	$ 125,222
27	G40 Low Annual-High Winter	$ 24,105	$ 25,117	$ 26,955	$ 27,812	$ 27,244	$ 29,310	$ 631,266	$ 160,543
28	G51 Med Annual-Low Winter	$ 25,141	$ 26,197	$ 28,114	$ 29,008	$ 28,415	$ 30,570	$ 658,403	$ 167,445
29	G41 Med Annual-High Winter	$ 29,960	$ 31,218	$ 33,502	$ 34,567	$ 33,861	$ 36,429	$ 784,591	$ 199,537
30	G52 High Annual-Low Winter	$ 1,062	$ 1,106	$ 1,197	$ 1,225	$ 1,200	$ 1,291	$ 27,816	$ 7,081
31	G42 High Annual-High Winter	$ 3,695	$ 3,850	$ 4,132	$ 4,263	$ 4,176	$ 4,493	$ 96,763	$ 24,609
32									
33	Residential	$ 87,700	$ 91,382	$ 98,069	$ 101,187	$ 99,119	$ 106,636	$ 2,296,684	$ 584,093
34	SALES HLF CLASSES	$ 45,005	$ 46,894	$ 50,336	$ 51,926	$ 50,865	$ 54,722	$ 1,178,598	$ 299,748
35	SALES LLF CLASSES	$ 57,760	$ 60,185	$ 64,590	$ 66,643	$ 65,281	$ 70,232	$ 1,512,620	$ 384,689

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
37	TOTAL BASE HEDGING COMMODITY	$ 63,902	$ -	$ -	$ -	$ -	$ 56,299	$ 241,940	$ 120,200
38	Res Heat	$ 28,382	$ -	$ -	$ -	$ -	$ 25,005	$ 107,456	$ 53,386
39	Res General	$ 1,042	$ -	$ -	$ -	$ -	$ 918	$ 3,946	$ 1,960
40	G50 Low Annual-Low Winter	$ 6,308	$ -	$ -	$ -	$ -	$ 5,558	$ 23,883	$ 11,866
41	G40 Low Annual-High Winter	$ 8,087	$ -	$ -	$ -	$ -	$ 7,125	$ 30,620	$ 15,213
42	G51 Med Annual-Low Winter	$ 8,435	$ -	$ -	$ -	$ -	$ 7,431	$ 31,936	$ 15,866
43	G41 Med Annual-High Winter	$ 10,052	$ -	$ -	$ -	$ -	$ 8,856	$ 38,057	$ 18,907
44	G52 High Annual-Low Winter	$ 356	$ -	$ -	$ -	$ -	$ 314	$ 1,349	$ 670
45	G42 High Annual-High Winter	$ 1,240	$ -	$ -	$ -	$ -	$ 1,092	$ 4,694	$ 2,332
46									
47	Residential	$ 29,424	$ -	$ -	$ -	$ -	$ 25,923	$ 111,402	$ 55,347
48	SALES HLF CLASSES	$ 15,099	$ -	$ -	$ -	$ -	$ 13,303	$ 57,168	$ 28,402
49	SALES LLF CLASSES	$ 19,379	$ -	$ -	$ -	$ -	$ 17,073	$ 73,370	$ 36,452

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	
2	**Total Therms**	
3	Res Heat	Schedule 10B, LN 52
4	Res General	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	Schedule 10B, LN 58
10	G42 High Annual-High Winter	Schedule 10B, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12	**% of Total**	
13	Res Heat	LN 3 / LN 11
14	Res General	LN 4 / LN 11
15	G50 Low Annual-Low Winter	LN 5 / LN 11
16	G40 Low Annual-High Winter	LN 6 / LN 11
17	G51 Med Annual-Low Winter	LN 7 / LN 11
18	G41 Med Annual-High Winter	LN 8 / LN 11
19	G52 High Annual-Low Winter	LN 9 / LN 11
20	G42 High Annual-High Winter	LN 10 / LN 11
21	Total Firm Sales	LN 11 / LN 11

22	**BASE COMMODITY COSTS Excld Hedging**	
23	TOTAL BASE COMMODITY Excld Hedging	Schedule 1B, LN 37
24	Res Heat	LN 23 * LN 13
25	Res General	LN 23 * LN 14
26	G50 Low Annual-Low Winter	LN 23 * LN 15
27	G40 Low Annual-High Winter	LN 23 * LN 16
28	G51 Med Annual-Low Winter	LN 23 * LN 17
29	G41 Med Annual-High Winter	LN 23 * LN 18
30	G52 High Annual-Low Winter	LN 23 * LN 19
31	G42 High Annual-High Winter	LN 23 * LN 20
32		
33	Residential	LN 24 + LN 25
34	SALES HLF CLASSES	LN 26 + LN 28 + LN 30
35	SALES LLF CLASSES	LN 27 + LN 29 + LN 31

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	
37	TOTAL BASE HEDGING COMMODITY	Schedule 1B, LN 38
38	Res Heat	LN 13 * LN 37
39	Res General	LN 14 * LN 37
40	G50 Low Annual-Low Winter	LN 15 * LN 37
41	G40 Low Annual-High Winter	LN 16 * LN 37
42	G51 Med Annual-Low Winter	LN 17 * LN 37
43	G41 Med Annual-High Winter	LN 18 * LN 37
44	G52 High Annual-Low Winter	LN 19 * LN 37
45	G42 High Annual-High Winter	LN 20 * LN 37
46		
47	Residential	LN 38 + LN 39
48	SALES HLF CLASSES	LN 40 + LN 42 + LN 44
49	SALES LLF CLASSES	LN 41 + LN 43 + LN 45

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

Remaining Commodity Costs

	REMAINING SENDOUT BY CLASS	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	OFF-PEAK
51	**Total Therms**								
52	Res Heat	125,906	22,881	-	4,150	60,189	302,539	11,152,337	515,664
53	Res General	4,623	840	-	152	2,210	11,109	131,037	18,934
54	G50 Low Annual-Low Winter	27,984	5,086	-	922	13,377	67,242	570,865	114,611
55	G40 Low Annual-High Winter	35,877	6,520	-	1,182	17,151	86,209	5,770,873	146,939
56	G51 Med Annual-Low Winter	37,420	6,800	-	1,233	17,888	89,915	763,279	153,256
57	G41 Med Annual-High Winter	44,591	8,104	-	1,470	21,317	107,148	4,621,158	182,629
58	G52 High Annual-Low Winter	804	572	-	4	221	390	21,046	1,991
59	G42 High Annual-High Winter	5,499	999	-	181	2,629	13,215	688,132	22,524
60	Total Firm Sales	282,705	51,802	-	9,295	134,982	677,765	23,718,727	1,156,549
61	**% of Total**								
62	Res Heat	44.54%	44.17%	44.64%	44.64%	44.59%	44.64%		
63	Res General	1.64%	1.62%	1.64%	1.64%	1.64%	1.64%		
64	G50 Low Annual-Low Winter	9.90%	9.82%	9.92%	9.92%	9.91%	9.92%		
65	G40 Low Annual-High Winter	12.69%	12.59%	12.72%	12.72%	12.71%	12.72%		
66	G51 Med Annual-Low Winter	13.24%	13.13%	13.27%	13.27%	13.25%	13.27%		
67	G41 Med Annual-High Winter	15.77%	15.64%	15.81%	15.81%	15.79%	15.81%		
68	G52 High Annual-Low Winter	0.28%	1.10%	0.04%	0.04%	0.16%	0.06%		
69	G42 High Annual-High Winter	1.95%	1.93%	1.95%	1.95%	1.95%	1.95%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	REMAINING COMMODITY COSTS EXCLD HEDGING	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	OFF-PEAK
72	REMAINING COMMODITY Excld Hedging	$ 52,577	$ 12,156	$ 2,252	$ 4,069	$ 29,911	$ 147,688	$ 11,585,194	$ 248,652
73	Res Heat	$ 23,416	$ 5,369	$ 1,005	$ 1,816	$ 13,337	$ 65,925	$ 5,456,068	$ 110,869
74	Res General	$ 860	$ 197	$ 37	$ 67	$ 490	$ 2,421	$ 60,082	$ 4,071
75	G50 Low Annual-Low Winter	$ 5,204	$ 1,193	$ 223	$ 404	$ 2,964	$ 14,652	$ 251,700	$ 24,642
76	G40 Low Annual-High Winter	$ 6,672	$ 1,530	$ 286	$ 518	$ 3,800	$ 18,785	$ 2,860,780	$ 31,592
77	G51 Med Annual-Low Winter	$ 6,959	$ 1,596	$ 299	$ 540	$ 3,964	$ 19,593	$ 336,533	$ 32,950
78	G41 Med Annual-High Winter	$ 8,293	$ 1,902	$ 356	$ 643	$ 4,724	$ 23,348	$ 2,270,521	$ 39,265
79	G52 High Annual-Low Winter	$ 150	$ 134	$ 1	$ 2	$ 49	$ 85	$ 9,949	$ 420
80	G42 High Annual-High Winter	$ 1,023	$ 235	$ 44	$ 79	$ 583	$ 2,880	$ 339,562	$ 4,843
81									
82	Residential	$ 24,276	$ 5,567	$ 1,042	$ 1,883	$ 13,827	$ 68,345	$ 5,516,149	$ 114,939
83	SALES HLF CLASSES	$ 12,313	$ 2,923	$ 523	$ 945	$ 6,977	$ 34,330	$ 598,183	$ 58,012
84	SALES LLF CLASSES	$ 15,988	$ 3,666	$ 686	$ 1,240	$ 9,107	$ 45,013	$ 5,470,862	$ 75,700

85	REMAINING COMMODITY HEDGING COSTS	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	OFF-PEAK
86	TOTAL REMAINING COMMODITY HEDGING	$ 16,342	$ -	$ -	$ -	$ -	$ 35,040	$ 177,198	$ 51,382
87	Res Heat	$ 7,278	$ -	$ -	$ -	$ -	$ 15,641	$ 82,222	$ 22,919
88	Res General	$ 267	$ -	$ -	$ -	$ -	$ 574	$ 1,473	$ 842
89	G50 Low Annual-Low Winter	$ 1,618	$ -	$ -	$ -	$ -	$ 3,476	$ 7,680	$ 5,094
90	G40 Low Annual-High Winter	$ 2,074	$ -	$ -	$ -	$ -	$ 4,457	$ 37,828	$ 6,531
91	G51 Med Annual-Low Winter	$ 2,163	$ -	$ -	$ -	$ -	$ 4,649	$ 10,270	$ 6,812
92	G41 Med Annual-High Winter	$ 2,578	$ -	$ -	$ -	$ -	$ 5,539	$ 32,848	$ 8,117
93	G52 High Annual-Low Winter	$ 46	$ -	$ -	$ -	$ -	$ 20	$ 170	$ 67
94	G42 High Annual-High Winter	$ 318	$ -	$ -	$ -	$ -	$ 683	$ 4,708	$ 1,001
95								$ -	$ -
96	Residential	$ 7,545	$ -	$ -	$ -	$ -	$ 16,215	$ 83,694	$ 23,761
97	SALES HLF CLASSES	$ 3,827	$ -	$ -	$ -	$ -	$ 8,145	$ 18,120	$ 11,972
98	SALES LLF CLASSES	$ 4,969	$ -	$ -	$ -	$ -	$ 10,680	$ 75,384	$ 15,649

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	LN 60 / LN 60, Jul/Aug calculated together

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	
72	REMAINING COMMODITY Excld Hedging	Schedule 1B, LN 39
73	Res Heat	LN 72 * LN 62
74	Res General	LN 72 * LN 63
75	G50 Low Annual-Low Winter	LN 72 * LN 64
76	G40 Low Annual-High Winter	LN 72 * LN 65
77	G51 Med Annual-Low Winter	LN 72 * LN 66
78	G41 Med Annual-High Winter	LN 72 * LN 67
79	G52 High Annual-Low Winter	LN 72 * LN 68
80	G42 High Annual-High Winter	LN 72 * LN 69
81		
82	Residential	LN 73 + LN 74
83	SALES HLF CLASSES	LN 75 + LN 77 + LN 79
84	SALES LLF CLASSES	LN 76 + LN 78 + LN 80

85	**REMAINING COMMODITY HEDGING COSTS**	
86	TOTAL REMAINING COMMODITY HEDGING	Schedule 1B, LN 40
87	Res Heat	LN 62 * LN 86
88	Res General	LN 63 * LN 86
89	G50 Low Annual-Low Winter	LN 64 * LN 86
90	G40 Low Annual-High Winter	LN 65 * LN 86
91	G51 Med Annual-Low Winter	LN 66 * LN 86
92	G41 Med Annual-High Winter	LN 67 * LN 86
93	G52 High Annual-Low Winter	LN 68 * LN 86
94	G42 High Annual-High Winter	LN 69 * LN 86
95		
96	Residential	LN 87 + LN 88
97	SALES HLF CLASSES	LN 89 + LN 91 + LN 93
98	SALES LLF CLASSES	LN 90 + LN 92 + LN 94

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
100	TOTAL COMMODITY Excld Hedging	$ 243,041	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 379,278	$ 16,573,096	$ 1,517,183
101	Res Heat	$ 108,009	$ 93,515	$ 95,601	$ 99,419	$ 108,946	$ 168,784	$ 7,671,410	$ 674,274
102	Res General	$ 3,966	$ 3,434	$ 3,510	$ 3,650	$ 4,000	$ 6,197	$ 141,424	$ 24,758
103	G50 Low Annual-Low Winter	$ 24,006	$ 20,784	$ 21,248	$ 22,097	$ 24,214	$ 37,514	$ 744,080	$ 149,864
104	G40 Low Annual-High Winter	$ 30,777	$ 26,647	$ 27,242	$ 28,330	$ 31,044	$ 48,095	$ 3,492,045	$ 192,136
105	G51 Med Annual-Low Winter	$ 32,101	$ 27,793	$ 28,413	$ 29,548	$ 32,379	$ 50,163	$ 994,936	$ 200,395
106	G41 Med Annual-High Winter	$ 38,253	$ 33,119	$ 33,858	$ 35,211	$ 38,584	$ 59,777	$ 3,055,111	$ 238,803
107	G52 High Annual-Low Winter	$ 1,211	$ 1,241	$ 1,198	$ 1,227	$ 1,249	$ 1,376	$ 37,765	$ 7,502
108	G42 High Annual-High Winter	$ 4,718	$ 4,085	$ 4,176	$ 4,343	$ 4,759	$ 7,372	$ 436,325	$ 29,451
109									
110	Residential	$ 111,975	$ 96,948	$ 99,112	$ 103,070	$ 112,946	$ 174,981	$ 7,812,834	$ 699,032
111	SALES HLF CLASSES	$ 57,318	$ 49,818	$ 50,859	$ 52,871	$ 57,842	$ 89,053	$ 1,776,781	$ 357,761
112	SALES LLF CLASSES	$ 73,748	$ 63,851	$ 65,276	$ 67,883	$ 74,387	$ 115,244	$ 6,983,482	$ 460,390

113	**TOTAL HEDGING COMMODITY COSTS**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
114	TOTAL HEDGING COMMODITY	$ 80,243	$ -	$ -	$ -	$ -	$ 91,339	$ 419,138	$ 171,582
115	Res Heat	$ 35,660	$ -	$ -	$ -	$ -	$ 40,646	$ 189,678	$ 76,305
116	Res General	$ 1,309	$ -	$ -	$ -	$ -	$ 1,492	$ 5,418	$ 2,802
117	G50 Low Annual-Low Winter	$ 7,926	$ -	$ -	$ -	$ -	$ 9,034	$ 31,564	$ 16,960
118	G40 Low Annual-High Winter	$ 10,161	$ -	$ -	$ -	$ -	$ 11,582	$ 68,448	$ 21,743
119	G51 Med Annual-Low Winter	$ 10,598	$ -	$ -	$ -	$ -	$ 12,080	$ 42,206	$ 22,678
120	G41 Med Annual-High Winter	$ 12,629	$ -	$ -	$ -	$ -	$ 14,395	$ 70,905	$ 27,024
121	G52 High Annual-Low Winter	$ 403	$ -	$ -	$ -	$ -	$ 334	$ 1,518	$ 737
122	G42 High Annual-High Winter	$ 1,558	$ -	$ -	$ -	$ -	$ 1,775	$ 9,401	$ 3,333
123									
124	Residential	$ 36,969	$ -	$ -	$ -	$ -	$ 42,138	$ 195,096	$ 79,107
125	SALES HLF CLASSES	$ 18,926	$ -	$ -	$ -	$ -	$ 21,448	$ 75,288	$ 40,374
126	SALES LLF CLASSES	$ 24,348	$ -	$ -	$ -	$ -	$ 27,753	$ 148,754	$ 52,101

127	TOTAL COMMODITY	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
128	Res Heat	$ 143,669	$ 93,515	$ 95,601	$ 99,419	$ 108,946	$ 209,430	$ 7,861,087	$ 750,580
129	Res General	$ 5,275	$ 3,434	$ 3,510	$ 3,650	$ 4,000	$ 7,690	$ 146,842	$ 27,560
130	G50 Low Annual-Low Winter	$ 31,932	$ 20,784	$ 21,248	$ 22,097	$ 24,214	$ 46,548	$ 775,643	$ 166,823
131	G40 Low Annual-High Winter	$ 40,939	$ 26,647	$ 27,242	$ 28,330	$ 31,044	$ 59,677	$ 3,560,493	$ 213,879
132	G51 Med Annual-Low Winter	$ 42,699	$ 27,793	$ 28,413	$ 29,548	$ 32,379	$ 62,243	$ 1,037,142	$ 223,073
133	G41 Med Annual-High Winter	$ 50,882	$ 33,119	$ 33,858	$ 35,211	$ 38,584	$ 74,172	$ 3,126,016	$ 265,827
134	G52 High Annual-Low Winter	$ 1,614	$ 1,241	$ 1,198	$ 1,227	$ 1,249	$ 1,710	$ 39,283	$ 8,239
135	G42 High Annual-High Winter	$ 6,275	$ 4,085	$ 4,176	$ 4,343	$ 4,759	$ 9,148	$ 445,726	$ 32,784
136	Total Firm Sales	$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 16,992,234	$ 1,688,765
137									
138	Residential	$ 148,944	$ 96,948	$ 99,112	$ 103,070	$ 112,946	$ 217,120	$ 8,007,930	$ 778,139
139	SALES HLF CLASSES	$ 76,244	$ 49,818	$ 50,859	$ 52,871	$ 57,842	$ 110,500	$ 1,852,069	$ 398,135
140	SALES LLF CLASSES	$ 98,096	$ 63,851	$ 65,276	$ 67,883	$ 74,387	$ 142,997	$ 7,132,235	$ 512,490
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								43.72%
144	SALES LLF CLASSES								56.28%

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

Total Commodity Costs

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

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

Northern Utilities, Inc.
Normal Weather - Sales Service Only
Commodity Volumes by Supply Source (Dth)
May 2012 through October 2012

Description	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Season
Pipeline Supplies							
Chicago	0	0	0	0	0	0	0
Lewiston Baseload	77,500	75,000	77,500	77,500	75,000	77,500	460,000
PNGTS	30,892	29,895	30,892	30,892	29,895	30,892	183,356
Niagara	0	0	0	0	0	0	0
Tennessee Production	77,314	33,538	19,487	20,408	42,300	148,522	341,568
Subtotal Pipeline	185,705	138,433	127,878	128,799	147,195	256,913	984,924
Underground Storage							
Tennessee Storage	0	0	0	0	0	0	0
Tenn Zone 4 Spot	75,233	72,806	75,233	75,233	72,806	75,233	446,542
Tennesse Storage Path	75,233	72,806	75,233	75,233	72,806	75,233	446,542
Washington 10 Storage	0	0	0	0	0	0	0
W10 AMA Spot	0	0	0	0	0	0	0
W10 Storage Path	0	0	0	0	0	0	0
Subtotal Storage	75,233	72,806	75,233	75,233	72,806	75,233	446,542
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Subtotal Peaking	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Total Delivered (Dth)	262,333	212,589	204,506	205,427	221,351	333,541	1,439,746

Schedule 11B

Provided in Winter 2011-12 Cost-of-Gas Filing

Northern Utilities, Inc.
Normal Weather - Sales Service Only
Capacity Utilization by Supply Source
May 2012 through October 2012

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Chicago	0	1,086,509	0%
Lewiston Baseload	460,000	460,000	100%
PNGTS	183,356	185,081	99%
Niagara	0	393,805	0%
Tennessee Production	341,568	2,213,715	15%
Subtotal Pipeline	984,924	4,339,110	23%
Underground Storage			
Tennessee Storage	0		
Tenn Zone 4 Spot	446,542		
Tennesse Storage Path	446,542	446,542	100%
Washington 10 Storage	0		
W10 AMA Spot			
W10 Storage Path	0	0	
Subtotal Storage	446,542	446,542	100%
Peaking Supplies			
Peaking Supply 1		0	
Peaking Supply 2		0	
Peaking Supply 3		0	
LNG	8,280	1,688,699	0%
Subtotal Peaking	8,280	1,688,699	0%
Total Delivered (Dth)	1,439,746	6,474,350	22%

Schedule 11D

Provided in Winter 2011-12 Cost-of-Gas Filing

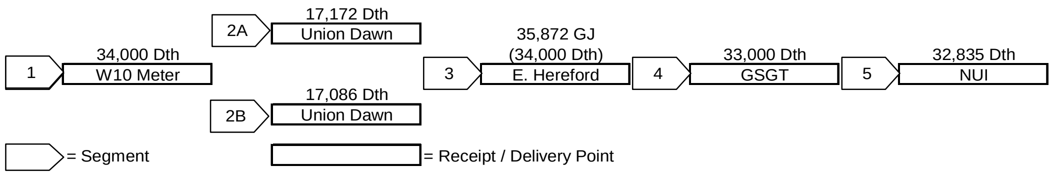
Schedule 12

Northern Capacity by Supply Source (Dth per Day)		
Supply Source	2011-2012 Winter	2012 Summer
Washington 10 Path	32,885	0
Tennessee Long-Haul	13,109	13,109
Chicago Path	6,434	6,434
Tennessee Niagara	3,282	2,332
Tennessee FS-MA & 5265	2,644	2,644
PNGTS Year-Round	1,096	1,096
Peaking Supply 1	9,965	0
Peaking Supply 2	9,965	0
Peaking Supply 3	11,958	0
Lewiston On-System LNG Production	10,000	10,000
Lewiston Baseload	5,500	0
Total Deliverable Resources	**106,838**	**35,615**

Released Capacity	
Supply Source	Capacity Release Volumes
Texas Eastern Production and Storage & Algonquin (Centerville, NJ)	286
Texas Eastern Zone M3	965
Total Released Capacity	**1,251**

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

Capacity Path Diagram



Capacity Path Detail

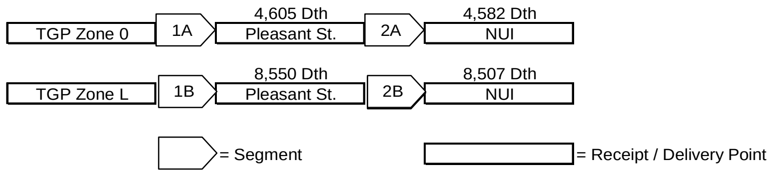
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	32,885	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,885	Dth				

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

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

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

Capacity Path Diagram



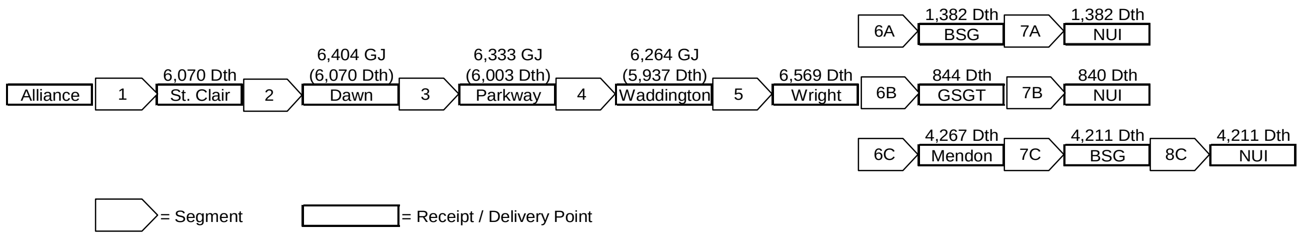
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

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

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Chicago (Interconnection of Alliance and Vector Pipelines)

Capacity Path Diagram

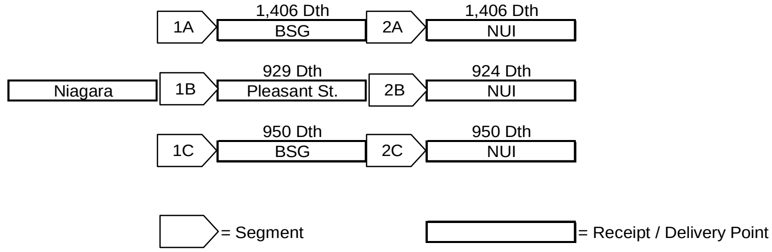


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	Union
3	Transportation	Union	M12205	M12	10/31/2017	6,333	GJ	Year-Round	Dawn	Parkway	TransCanada
4	Transportation	TransCanada	41235	FT	10/31/2017	6,264	GJ	Year-Round	Parkway	Waddington	Iroquois
5	Transportation	Iroquois	R181001	RTS-1	10/31/2017	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
6A	Transportation	Tennessee	95196	FT-A	10/31/2017	1,382	Dth	Year-Round	Wright	Bay State City Gate	
7A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
6B	Transportation	Tennessee	95196	FT-A	10/31/2017	844	Dth	Year-Round	Wright	Pleasant St.	Granite
7B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	841	Dth	Year-Round	Granite	Northern City Gates	
6C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
7C	Transportation	Algonquin	93200F	AFT-1	10/31/2012	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
8C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

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

Capacity Path Diagram

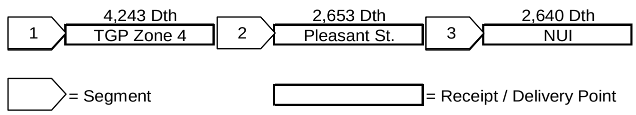


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2015	1,406	Dth	Year-Round	Niagara	Bay State City Gate	
2A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,406	Dth	Year-Round	Bay State City Gate	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2015	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	926	Dth	Year-Round	Granite	Northern City Gates	
1C	Transportation	Tennessee	46314	FT-A	3/31/2012	950	Dth	Year-Round	Niagara	Bay State City Gate	
2C	Exchange	Bay State Gas	NA	NA	Renewal Clause	950	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						3,282	Dth				

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

Capacity Path Diagram



Capacity Path Detail

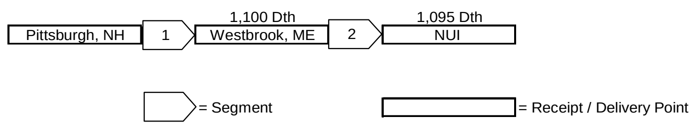
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2015	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2015	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

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

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

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

Capacity Path Diagram

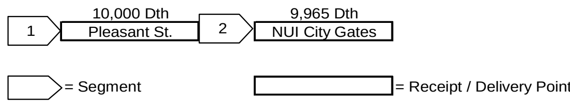


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	1,096	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,096	Dth				

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

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2012	10,000	Dth	Winter Only (Nov - Mar)	NA	Pleasant St.	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	9,965	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						9,965	Dth				

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

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

Capacity Path Diagram

1 → 10,000 Dth Newington or Westbrook → 2 → 9,965 Dth NUI City Gates

= Segment = Receipt / Delivery Point

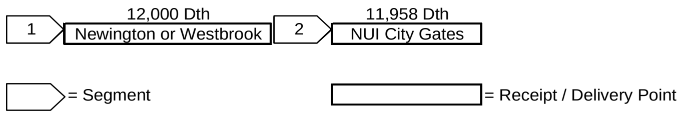
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2012	10,000	Dth	Winter Only (Nov-Mar)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	9,965	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						9,965	Dth				

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

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

Capacity Path Diagram



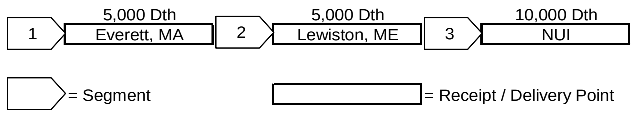
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	2/29/2012	12,000	Dth	Winter Only (Dec-Feb)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	11,958	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						11,958	Dth				

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

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

Capacity Path Diagram



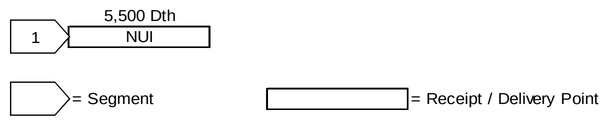
Capacity Path Detail

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

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

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

Capacity Path Diagram

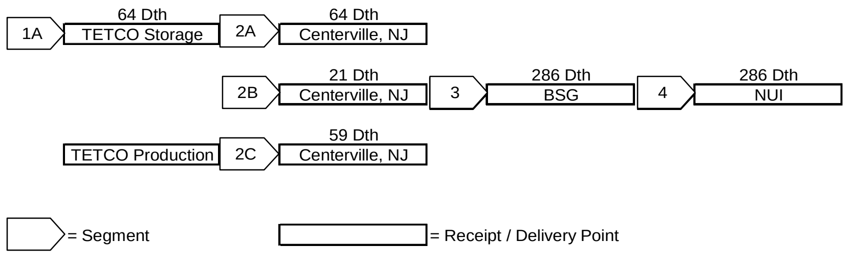


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Delivered Supply	Confidential	NA	NA	3/31/2012	5,500	Dth	NA	NA	Northern City Gate (Lewiston)	NA
Total Path Deliverable						5,500	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Texas Eastern Production and Storage & Algonquin (Centerville, NJ)

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Storage	Texas Eastern	400513	FSS-1	4/30/2012	64	Dth	Year-Round		Texas Eastern M3 Storage	
2A	Transportation	Texas Eastern	800436	CDS	10/31/2012	64	Dth	Year-Round	Texas Eastern M3 Storage	Centerville, NJ	Algonquin
2B[2]	Storage	Texas Eastern	400215	SS-1	4/30/2013	21	Dth	Year-Round	Texas Eastern M3 Storage	Centerville, NJ	Algonquin
2C	Transportation	Texas Eastern	800464	CDS	10/31/2012	59	Dth	Year-Round	Texas Eastern Production Area	Centerville, NJ	Algonquin
3[3,4]	Transportation	Algonquin	93201A1C	AFT-1	10/31/2013	286	Dth	Year-Round	Centerville, NJ	Bay State City Gate	
4	Exchange	Bay State Gas	NA	NA	Renewal Clause	286	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						286	Dth				

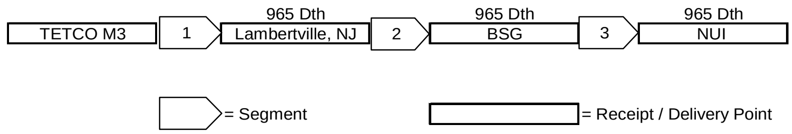
Note 1: Texas Eastern Contract No. 400513 has a maximum storage quantity of 3,840 Dth.

Note 2: Texas Eastern Contract No. 400215 has a maximum storage quantity of 1,470 Dth.

Note 3: Northern has entered into a permanent release of Algonquin Contract No. 93201A1C. As such, these supplies are not deliverable to Northern City Gates. Northern plans to continue to seek permanent release of the other Texas Eastern contracts in this capacity path.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Texas Eastern Zone M3

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Transportation	Texas Eastern	800384	FT-1	10/31/2017	965	Dth	Year-Round	Texas Eastern M3 Storage	Lambertville, NJ	Algonquin
2[1,2]	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2013	965	Dth	Year-Round	Lambertville, NJ	Bay State City Gate	
3	Exchange	Bay State Gas	NA	NA	Renewal Clause	965	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						965	Dth				

Note 1: Northern has entered into a release of both Texas Eastern Contract No. 800384 and Algonquin Contract No. 93201A1C. As such, these supplies are not deliverable to Northern City Gates.

Schedule 13

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

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

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

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

Schedule 14

Northern Utilities, Inc.
Storage Inventory and Activity Costs

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-11	201,401	-	-	201,401	$ 906,261	$ 4.50	NA	$ -	$ 4.50	$ -	$ 906,261	2.19%	$ 1,651	$ 906,261	$ -
Dec-11	201,401	-	12,349	189,052	$ 906,261	$ 4.50	NA	$ -	$ 4.50	$ 55,568	$ 850,692	2.19%	$ 1,601	$ 850,692	$ 55,568
Jan-12	189,052	-	64,554	124,498	$ 850,692	$ 4.50	NA	$ -	$ 4.50	$ 290,480	$ 560,213	2.19%	$ 1,285	$ 560,213	$ 290,480
Feb-12	124,498	-	60,389	64,108	$ 560,213	$ 4.50	NA	$ -	$ 4.50	$ 271,739	$ 288,474	2.19%	$ 773	$ 288,474	$ 271,739
Mar-12	64,108	-	64,108	-	$ 288,474	$ 4.50	NA	$ -	$ 4.50	$ 288,474	$ -	2.19%	$ 263	$ -	$ 288,474
Apr-12	-	-	-	-	$ -	NA	NA	$ -	$ 4.69	$ -	$ -	2.19%	$ -	$ -	$ -
May-12	-	53,599	-	53,599		NA	$ 3.07	$ 164,686	$ 3.07	$ -	$ 164,686	2.19%	$ 150	$ 164,686	$ -
Jun-12	53,599	51,870	-	105,469	$ 164,686	$ 3.07	$ 3.17	$ 164,259	$ 3.12	$ -	$ 328,944	2.19%	$ 450	$ 328,944	$ -
Jul-12	105,469	53,599	-	159,068	$ 328,944	$ 3.12	$ 3.24	$ 173,548	$ 3.16	$ -	$ 502,493	2.19%	$ 757	$ 502,493	$ -
Aug-12	159,068	42,333	-	201,401	$ 502,493	$ 3.16	$ 3.27	$ 138,577	$ 3.18	$ -	$ 641,069	2.19%	$ 1,042	$ 641,068	$ -
Sep-12	201,401	-	-	201,401	$ 641,069	$ 3.18	NA	$ -	$ 3.18	$ -	$ 641,069	2.19%	$ 1,168	$ 641,068	$ -
Oct-12	201,401	-	-	201,401	$ 641,069	$ 3.18	NA	$ -	$ 3.18	$ -	$ 641,069	2.19%	$ 1,168	$ 641,068	$ -

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-11	2,640,440	-	86,461	2,553,979	$11,559,846	$ 4.38	NA	$ -	$ 4.38	$ 378,526	$ 11,181,320	2.19%		$ 11,181,320	$ 378,526
Dec-11	2,553,979	-	460,219	2,093,760	$11,181,320	$ 4.38	NA	$ -	$ 4.38	$2,014,840	$ 9,166,479	2.19%		$ 9,166,479	$2,014,840
Jan-12	2,093,760	-	776,610	1,317,150	$ 9,166,479	$ 4.38	NA	$ -	$ 4.38	$3,399,998	$ 5,766,482	2.19%		$ 5,766,482	$3,399,998
Feb-12	1,317,150	-	711,271	605,879	$ 5,766,482	$ 4.38	NA	$ -	$ 4.38	$3,113,945	$ 2,652,537	2.19%		$ 2,652,537	$3,113,945
Mar-12	605,879	-	341,835	264,044	$ 2,652,537	$ 4.38	NA	$ -	$ 4.38	$1,496,552	$ 1,155,985	2.19%		$ 1,155,985	$1,496,552
Apr-12	264,044	391,709	-	655,753	$ 1,155,985	$ 4.38	$ 2.97	$1,164,331	$ 3.54	$ -	$ 2,320,315	2.19%		$ 2,320,315	$ -
May-12	655,753	404,766	-	1,060,520	$ 2,320,315	$ 3.54	$ 2.89	$1,168,885	$ 3.29	$ -	$ 3,489,200	2.19%		$ 3,489,200	$ -
Jun-12	1,060,520	391,709	-	1,452,229	$ 3,489,200	$ 3.29	$ 2.98	$1,166,666	$ 3.21	$ -	$ 4,655,865	2.19%		$ 4,655,865	$ -
Jul-12	1,452,229	404,766	-	1,856,995	$ 4,655,865	$ 3.21	$ 3.05	$1,233,431	$ 3.17	$ -	$ 5,889,296	2.19%		$ 5,889,296	$ -
Aug-12	1,856,995	404,766	-	2,261,761	$ 5,889,296	$ 3.17	$ 3.08	$1,247,452	$ 3.16	$ -	$ 7,136,748	2.19%		$ 7,136,748	$ -
Sep-12	2,261,761	378,679	-	2,640,440	$ 7,136,748	$ 3.16	$ 3.09	$1,170,909	$ 3.15	$ -	$ 8,307,657	2.19%		$ 8,307,657	$ -
Oct-12	2,640,440	-	-	2,640,440	$ 8,307,657	$ 3.15	NA	$ -	$ 3.15	$ -	$ 8,307,657	2.19%		$ 8,307,657	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-11	9,708	1,350	1,350	9,708	$ 63,960	$ 6.59	$ 4.94	$ 6,672	$ 6.39	$ 8,623	$ 62,009	2.19%	$ 115	$ 62,009	$ 8,623
Dec-11	9,708	1,395	1,395	9,708	$ 62,009	$ 6.39	$ 6.15	$ 8,575	$ 6.36	$ 8,869	$ 61,715	2.19%	$ 113	$ 61,715	$ 8,869
Jan-12	9,708	2,482	3,453	8,737	$ 61,715	$ 6.36	$ 7.26	$ 18,013	$ 6.54	$ 22,583	$ 57,145	2.19%	$ 108	$ 57,145	$ 22,583
Feb-12	8,737	1,305	1,305	8,737	$ 57,145	$ 6.54	$ 6.67	$ 8,707	$ 6.56	$ 8,558	$ 57,294	2.19%	$ 104	$ 57,294	$ 8,558
Mar-12	8,737	1,395	1,395	8,737	$ 57,294	$ 6.56	$ 4.34	$ 6,058	$ 6.25	$ 8,723	$ 54,630	2.19%	$ 102	$ 54,630	$ 8,723
Apr-12	8,737	4,091	3,120	9,707	$ 54,630	$ 6.25	$ 3.99	$ 16,314	$ 5.53	$ 17,255	$ 53,688	2.19%	$ 99	$ 53,688	$ 17,255
May-12	9,708	1,395	1,395	9,708	$ 53,688	$ 5.53	$ 4.10	$ 5,715	$ 5.35	$ 7,464	$ 51,940	2.19%	$ 96	$ 51,940	$ 7,464
Jun-12	9,708	1,350	1,350	9,708	$ 51,940	$ 5.35	$ 4.19	$ 5,652	$ 5.21	$ 7,031	$ 50,561	2.19%	$ 93	$ 50,561	$ 7,031
Jul-12	9,708	1,395	1,395	9,708	$ 50,561	$ 5.21	$ 4.25	$ 5,936	$ 5.09	$ 7,099	$ 49,398	2.19%	$ 91	$ 49,398	$ 7,099
Aug-12	9,708	1,395	1,395	9,708	$ 49,398	$ 5.09	$ 4.29	$ 5,983	$ 4.99	$ 6,958	$ 48,423	2.19%	$ 89	$ 48,423	$ 6,958
Sep-12	9,708	1,350	1,350	9,708	$ 48,423	$ 4.99	$ 4.30	$ 5,804	$ 4.90	$ 6,620	$ 47,606	2.19%	$ 87	$ 47,606	$ 6,620
Oct-12	9,708	1,395	1,395	9,708	$ 47,606	$ 4.90	$ 4.35	$ 6,071	$ 4.83	$ 6,744	$ 46,933	2.19%	$ 86	$ 46,933	$ 6,744

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER SEASON BALANCE
November 2010 - October 2011

	AMOUNT	
Summer Season Beg. Balance	$124,276	SCHEDULE 2
Less: Reported Collections	($4,448,096)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,181,875	SCHEDULE 4
Add: Interest	($9,847)	SCHEDULE 2
Summer Season Ending Balance	($151,792)	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER SEASON ACCOUNTS
November 2010 - October 2011
Acct 191.10

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
SUMMER SEASON													
Summer Season Account Beginning Balance	$ 124,276	$ (325,555)	$ (341,280)	$ (336,938)	$ (339,413)	$ (340,165)	$ (338,809)	$ (571,906)	$ (327,783)	$ (343,054)	$ (213,771)	$ (148,207)	$ 124,276
Plus: Cost of Firm Gas (Schedule 4)	$ (35,840)	$ (17,163)	$ -	$ -	$ -	$ 2,421	$ 953,180	$ 636,605	$ 515,005	$ 653,721	$ 590,583	$ 883,363	$ 4,181,875
Less: Reported Collections (Schedule 3)	$ (413,719)	$ 2,341	$ 5,259	$ (1,560)	$ 167	$ (147)	$ (1,185,045)	$ (391,265)	$ (529,369)	$ (523,685)	$ (524,529)	$ (886,543)	$ (4,448,096)
Summer Season Account Ending Balance	$ (325,283)	$ (340,378)	$ (336,020)	$ (338,498)	$ (339,246)	$ (337,891)	$ (570,674)	$ (326,566)	$ (342,147)	$ (213,018)	$ (147,717)	$ (151,386)	$ (141,945)
Month's Average Balance	$ (100,503)	$ (332,967)	$ (338,650)	$ (337,718)	$ (339,329)	$ (339,028)	$ (454,742)	$ (449,236)	$ (334,965)	$ (278,036)	$ (180,744)	$ (149,797)	
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	$ (272)	$ (902)	$ (917)	$ (915)	$ (919)	$ (918)	$ (1,232)	$ (1,217)	$ (907)	$ (753)	$ (490)	$ (406)	$ (9,847)
Summer Season Account Ending Balance w/int	$ (325,555)	$ (341,280)	$ (336,938)	$ (339,413)	$ (340,165)	$ (338,809)	$ (571,906)	$ (327,783)	$ (343,054)	$ (213,771)	$ (148,207)	$ (151,792)	$ (151,792)

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Accrued Revenue	$ (718,726)	$ -	$ -	$ -	$ -	$ -	$ 768,209	$ (474,534)	$ (52,089)	$ 49,568	$ (13,923)	$ 320,377	$ (121,116)
Billed Revenue	$ 1,132,445	$ (2,341)	$ (5,259)	$ 1,560	$ (167)	$ 147	$ 416,835	$ 865,798	$ 581,458	$ 474,117	$ 538,452	$ 566,166	$ 4,569,213
Calendarized Revenue	**$ 413,719**	**$ (2,341)**	**$ (5,259)**	**$ 1,560**	**$ (167)**	**$ 147**	**$ 1,185,045**	**$ 391,265**	**$ 529,369**	**$ 523,685**	**$ 524,529**	**$ 886,543**	**$ 4,448,096**

FORM III
Schedule 4
Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2010 - October 2011

Commodity Costs:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total Off Peak
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 582,422	$ -	$ -	$ -	$ -	**$ 582,422**
Distrigas	$ 180,377	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,330	**$ 196,708**
Emera Energy	$ 65,785	$ 3,974	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 69,758**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,448	$ -	$ -	**$ 330,448**
Portland	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51	$ 68	$ 66	**$ 184**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 267,049	$ 269,506	$ 608,931	$ 236,891	**$ 1,382,377**
Sempra	$ 4,956	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,956**
Sequent	$ 5,108	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,108**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 145,318	$ -	$ -	$ -	**$ 145,318**
Sprague Energy	$ 160,952	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 160,952**
Tennessee	$ 2,952	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,021	$ 2,657	$ 2,666	$ 2,701	$ 2,638	**$ 19,636**
Total Gas & Power	$ 309,204	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 309,204**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 338,212	$ 181,647	$ -	$ -	$ 284,920	**$ 804,780**
Subtotal	$ 729,333	$ 3,974	$ -	$ -	$ -	$ -	$ -	$ 926,656	$ 596,671	$ 602,670	$ 611,700	$ 540,845	**$ 4,011,849**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 960,537	$ 596,763	$ 604,312	$ 611,632	$ 529,963	$ 648,112	**$ 3,951,319**
Commodity Cost Reversals	$ (746,407)	$ -	$ -	$ -	$ -	$ -	$ -	$ (960,537)	$ (596,763)	$ (604,312)	$ (611,632)	$ (529,963)	**$ (4,049,614)**
Subtotal - Supply	$ (17,074)	$ 3,974	$ -	$ -	$ -	$ -	$ 960,537	$ 562,882	$ 604,220	$ 609,990	$ 530,031	$ 658,994	**$ 3,913,554**
Withdrawal Charges	$ (5,102)	$ -	$ -	$ -	$ -	$ -	$ (529)	$ 752	$ (297)	$ 775	$ (2,678)	$ (137)	**$ (7,216)**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,239	$ 18,793	$ 3,583	$ (17,344)	$ 6,329	$ 41,345	**$ 142,946**
Company Managed	$ (7,267)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (7,267)**
Non Traditional Sales	$ (69,697)	$ -	$ -	$ -	$ -	$ -	$ -	$ (340,132)	$ (164,840)	$ (283,329)	$ (162,598)	$ (170,241)	**$ (1,190,837)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,291	$ (8,977)	$ (8,710)	$ 988	$ 2,973	$ (10,532)	**$ (20,967)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,900	$ 4,436	$ 6,889	$ 5,731	$ 6,764	$ 4,524	**$ 34,244**
Transportation Charges	$ 14,248	$ (24,452)	$ -	$ -	$ -	$ 2,535	$ -	$ 1,394	$ (6,202)	$ -	$ 2,017	$ (5,696)	**$ (16,157)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,188	$ 1,833	$ 916	$ 1,090	$ 1,206	$ 66,231	**$ 95,463**
Allocation Adjustments	$ (32,432)	$ 3,315	$ -	$ -	$ -	$ (114)	$ 782	$ 11,427	$ (10,754)	$ 5,969	$ 2,917	$ (17,091)	**$ (35,980)**
Subtotal	$ (100,251)	$ (21,137)	$ -	$ -	$ -	$ 2,421	$ 123,871	$ (310,473)	$ (179,415)	$ (286,119)	$ (143,071)	$ (91,598)	**$ (1,005,771)**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (340,132)	$ (164,840)	$ (283,544)	$ (162,598)	$ (167,879)	$ (60,816)	**$ (1,179,809)**
Sales for Resale Reversals	$ 81,484	$ -	$ -	$ -	$ -	$ -	$ -	$ 340,132	$ 164,840	$ 283,544	$ 162,598	$ 167,879	**$ 1,200,477**
Total Commodity Costs	**$ (35,840)**	**$ (17,163)**	**$ -**	**$ -**	**$ -**	**$ 2,421**	**$ 744,276**	**$ 427,701**	**$ 306,101**	**$ 444,817**	**$ 381,679**	**$ 674,459**	**$ 2,928,451**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2010 - October 2011

Demand Costs	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total Off Peak
Forecasted Summer Demand Costs (DG 11-045)	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 1,227,460
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 25,964
Total Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 208,904	$ 208,904	$ 208,904	$ 208,904	$ 208,904	$ 208,904	$ 1,253,424
Total Gas Costs	$ (35,840)	$ (17,163)	$ -	$ -	$ -	$ 2,421	$ 953,180	$ 636,605	$ 515,005	$ 653,721	$ 590,583	$ 883,363	$ 4,181,875

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2010 - October 2011

New Hampshire	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Throughput IN													
BTU Factor	1.039	1.039	1.046	1.049	1.048	1.041	1.027	1.043	1.039	1.038	1.041	1.042	
GST Meter Throughput (MCF)	569,708	849,169	1,045,428	914,419	780,093	493,361	356,512	270,436	244,612	266,618	284,943	411,448	6,486,747
Salem Meter (MCF)	31,154	57,324	67,178	57,567	45,512	25,940	16,128	11,573	9,849	10,962	11,554	20,294	365,035
GST Meter Throughput (DTH)	591,927	882,287	1,093,518	959,226	817,537	513,589	366,138	282,065	254,152	276,749	296,626	428,729	6,762,541
Salem Meter (DTH)	32,369	59,560	70,268	60,388	47,697	27,004	16,563	12,071	10,233	11,379	12,028	21,146	380,705
LNG/Propane													-
Total Throughput	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701	294,135	264,385	288,128	308,653	449,875	7,143,246
Throughput OUT													
Residential Gas													
Charged	107,248	195,796	291,469	327,102	254,646	192,084	99,021	60,207	39,982	32,065	35,704	42,794	1,678,118
Uncharged Current	80,135	148,473	168,349	135,111	164,902	93,513	54,059	36,548	23,711	26,200	30,507	67,389	1,028,898
Uncharged Prior	(50,075)	(80,135)	(148,473)	(168,349)	(135,111)	(164,902)	(93,513)	(54,059)	(36,548)	(23,711)	(26,200)	(30,507)	(1,011,583)
Total Residential Gas	**137,308**	**264,134**	**311,345**	**293,864**	**284,436**	**120,695**	**59,567**	**42,695**	**27,145**	**34,555**	**40,010**	**79,677**	1,695,433
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	121,973	208,217	342,640	350,674	278,007	203,456	105,557	73,565	51,650	45,133	51,409	58,886	1,891,167
Uncharged Current	82,007	151,318	195,063	145,510	181,239	100,854	60,304	50,260	31,891	37,106	37,702	65,381	1,138,634
Uncharged Prior	(48,382)	(82,007)	(151,318)	(195,063)	(145,510)	(181,239)	(100,854)	(60,304)	(50,260)	(31,891)	(37,106)	(37,702)	(1,121,636)
Total C/I Gas	**155,597**	**277,528**	**386,386**	**301,121**	**313,736**	**123,071**	**65,006**	**63,521**	**33,281**	**50,348**	**52,005**	**86,565**	1,908,166
Transportation													
Charged	292,350	379,482	438,660	419,294	396,434	311,797	245,934	206,899	186,227	199,963	218,544	240,520	3,536,104
Uncharged Current	133,472	208,493	192,682	145,148	206,752	127,983	106,878	102,924	75,397	102,105	102,288	155,863	1,659,984
Uncharged Prior	(115,721)	(133,472)	(208,493)	(192,682)	(145,148)	(206,752)	(127,983)	(106,878)	(102,924)	(75,397)	(102,105)	(102,288)	(1,619,842)
Total Transportation	**310,101**	**454,503**	**422,850**	**371,759**	**458,038**	**233,029**	**224,829**	**202,945**	**158,700**	**226,671**	**218,726**	**294,095**	**3,576,246**
Company Use	**37**	**85**	**145**	**141**	**104**	**76**	**31**	**29**	**22**	**21**	**28**	**102**	**821**
Total Throughput OUT	**603,043**	**996,250**	**1,120,725**	**966,885**	**1,056,314**	**476,871**	**349,433**	**309,190**	**219,149**	**311,595**	**310,769**	**460,439**	**7,180,666**
Total Throughput IN	**624,296**	**941,846**	**1,163,786**	**1,019,613**	**865,234**	**540,592**	**382,701**	**294,135**	**264,385**	**288,128**	**308,653**	**449,875**	**7,143,246**
Difference IN/OUT	21,252	(54,404)	43,060	52,728	(191,080)	63,721	33,268	(15,055)	45,236	(23,467)	(2,116)	(10,563)	(37,420)
%													-0.52%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2010 - October 2011

SUMMER SEASON - Acct 182.21

		BEGINNING BALANCE	WORKING CAP ALLOWANCE (1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2010	$	(7,494)	(20)	0.0564%	(163)	(184)	(7,678)	(7,586)	3.25%	(21)	(7,698)
December	$	(7,698)	(10)	0.0564%	1	(9)	(7,707)	(7,702)	3.25%	(21)	(7,728)
January 2011	$	(7,728)	0	0.0564%	6	6	(7,722)	(7,725)	3.25%	(21)	(7,743)
February	$	(7,743)	0	0.0564%	(1)	(1)	(7,744)	(7,743)	3.25%	(21)	(7,765)
March	$	(7,765)	0	0.0564%	0	0	(7,765)	(7,765)	3.25%	(21)	(7,786)
April	$	(7,786)	1	0.0564%	0	1	(7,784)	(7,785)	3.25%	(21)	(7,805)
May	$	(7,805)	538	0.0564%	1,222	1,759	(6,046)	(6,926)	3.25%	(19)	(6,065)
June	$	(6,065)	359	0.0564%	420	779	(5,285)	(5,675)	3.25%	(15)	(5,301)
July	$	(5,301)	290	0.0564%	598	889	(4,412)	(4,856)	3.25%	(13)	(4,425)
August	$	(4,425)	369	0.0564%	540	908	(3,517)	(3,971)	3.25%	(11)	(3,528)
September	$	(3,528)	333	0.0564%	630	963	(2,565)	(3,046)	3.25%	(8)	(2,573)
October	$	(2,573)	498	0.0564%	1,101	1,599	(974)	(1,773)	3.25%	(5)	(978)

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

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SUMMER SEASON BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2010 - October 2011

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2010	3,159	(161)	0.45%	(1,297)	(1,458)	1,701	2,430	3.25%	7	1,708
December	1,708	(77)	0.45%	7	(70)	1,637	1,672	3.25%	5	1,642
January 2011	1,642	0	0.45%	23	23	1,665	1,654	3.25%	4	1,670
February	1,670	0	0.45%	(5)	(5)	1,664	1,667	3.25%	5	1,669
March	1,669	0	0.45%	1	1	1,669	1,669	3.25%	5	1,674
April	1,674	11	0.45%	(0)	11	1,685	1,679	3.25%	5	1,689
May	1,689	4,292	0.45%	(5,982)	(1,691)	(2)	844	3.25%	2	1
June	1	2,866	0.45%	(2,036)	831	831	416	3.25%	1	833
July	833	2,319	0.45%	(2,995)	(676)	156	494	3.25%	1	158
August	158	2,943	0.45%	(2,731)	213	370	264	3.25%	1	371
September	371	2,659	0.45%	(3,158)	(499)	(128)	122	3.25%	0	(127)
October	(127)	3,977	0.45%	(5,345)	(1,367)	(1,494)	(811)	3.25%	(2)	(1,497)

(1) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2011

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
Forecast Calendar Month Sales	164,519	104,668	82,572	94,844	113,688	179,773	740,064
Actual Sales	126,835	106,131	61,043	84,833	91,773	164,726	635,341
Difference	(37,684)	1,463	(21,529)	(10,011)	(21,915)	(15,047)	(104,723)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	128,741	106,131	61,043	84,833	91,773	215,607	688,128
Actual Sales	126,835	106,131	61,043	84,833	91,773	164,726	635,341
Weather Variance	1,906	-	-	-	-	50,881	52,787
Total Variance Excluding Weather (excl weather effect)	(35,778)	1,463	(21,529)	(10,011)	(21,915)	35,834	(51,936)
Variance-difference due to meter count							(5,942)
-difference in load pattern							(45,995)
SALES							(51,937)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2011

	NORMAL MMBtu			METERS		
	2011 Forecast	2011 Actual	Difference	2011 Forecast	2011 Actual	Difference
Res Heat	316,150	297,304	(18,846)	124,419	123,170	(1,249)
Res General	11,319	11,945	626	9,702	9,878	176
Total Res	327,469	309,249	(18,220)	134,121	133,048	(1,073)
G-40	87,368	95,090	7,722	25,152	24,971	(181)
G-50	72,599	70,067	(2,532)	5,460	5,421	(39)
G-41	131,026	120,820	(10,206)	2,210	2,194	(16)
G-51	96,646	79,198	(17,448)	907	900	(7)
G-42	10,791	10,444	(347)	70	69	(1)
G-52	14,164	3,258	(10,906)	30	30	(0)
Total C & I	412,594	378,877	(33,717)	33,829	33,585	(244)
Total Company	740,063	688,126	(51,937)	167,950	166,633	(1,317)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2011 Forecast	2011 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.54	2.41	(0.13)	(3,174)	(15,672)	(18,846)	-5.96%
Res General	1.17	1.21	0.04	205	421	626	5.53%
Total Res	3.71	3.62	(0.08)	(2,968)	(15,252)	(18,220)	-5.56%
G-40	3.47	3.81	0.33	(630)	8,352	7,722	8.84%
G-50	13.30	12.93	(0.37)	(523)	(2,009)	(2,532)	-3.49%
G-41	59.29	55.07	(4.22)	(944)	(9,262)	(10,206)	-7.79%
G-51	106.61	88.00	(18.61)	(697)	(16,751)	(17,448)	-18.05%
G-42	155.26	151.36	(3.90)	(78)	(269)	(347)	-3.22%
G-52	468.73	108.60	(360.13)	(102)	(10,804)	(10,906)	-77.00%
Total C & I	12.20	11.28	(0.92)	(2,974)	(30,743)	(33,717)	-8.17%
Total Company	4.41	4.13	(0.28)	(5,942)	(45,995)	(51,937)	-7.02%

Schedule 16

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 17

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 18

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 19

Provided in Winter 2011-12 Cost-of-Gas Filing

Schedule 20

		Off-Peak Season		Peak Season								
		May-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Peak Season	Off-Peak Season	Total Contracts
	Ceilings	*7.653*	*7.335*	*7.467*	*7.671*	*7.783*	*7.659*	*7.429*	*6.767*			
Scheduled Purchases	04/26/12	1	1	1	2	3	3	2	1	12	2	14
	05/29/12	1	1	2	2	3	2	2	1	12	2	14
	06/27/12	1	1	2	3	2	2	2	1	12	2	14
	07/27/12	1	1	1	2	3	3	2	1	12	2	14
	08/29/12	1	1	2	2	3	2	2	1	12	2	14
	09/26/12	1	1	2	3	2	2	2	2	13	2	15
	10/29/12	1	1	1	2	3	3	2	1	12	2	14
	11/28/12	1	1	2	2	3	2	2	1	12	2	14
	12/27/12	1	1	2	3	2	2	2	2	13	2	15
	01/29/13	1	1	1	2	3	2	3	1	12	2	14
	02/26/13	1	1	2	2	3	2	2	1	12	2	14
	03/26/13	0	2	1	3	2	3	2	2	13	2	15
Make-Up Purchases (white area) Scheduled Sales (gray area)	04/26/13	-11								0	-11	-11
	05/29/13									0	0	0
	06/26/13									0	0	0
	07/29/13									0	0	0
	08/28/13									0	0	0
	09/26/13		-13							0	-13	-13
	10/29/13			-19						-19	0	-19
	11/26/13				-28					-28	0	-28
	12/27/13					-32				-32	0	-32
	01/29/14						-28			-28	0	-28
	02/26/14							-25		-25	0	-25
	03/27/14								-15	-15	0	-15
	Scheduled	11	13	19	28	32	28	25	15	147	24	171
	check	0	0	0	0	0	0	0	0	0	0	0

*Note: Price Ceilings reflect 2012-13 levels and will be updated for 2013-14 with the Cost of Gas update in mid-April.

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts	City-Gate Volumes	Percent of Sendout	Futures Contracts	City-Gate Volumes	Percent of Sendout	Futures Contracts
	SUMMER PERIOD	SUMMER 2013			SUMMER 2014			SUMMER 2015		
1	Sendout Requirement (May, Oct)	594,186			601,049			614,685		
2	Financial Hedge Volume	240,000	40%	24	240,000	40%	24	250,000	41%	25
	WINTER PERIOD	WINTER 2013-14			WINTER 2014-15			WINTER 2015-16		
3	Sendout Requirement	5,586,772			5,695,344			5,812,207		
4	Washington 10 Storage	2,206,374	39%		2,206,374	39%		2,206,374	38%	
5	Tennessee Storage	230,740	4%		230,740	4%		230,740	4%	
6	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
7	Financial Hedge Volume	1,470,000	26%	147	1,550,000	27%	155	1,630,000	28%	163
8	Total Hedged Volume	3,907,114	70%		3,987,114	70%		4,067,114	70%	
	HEDGE PLAN YEAR	PLAN YEAR 2013-14			PLAN YEAR 2014-15			PLAN YEAR 2015-16		
9	Financial Hedge Volume	1,710,000	28%	171	1,790,000	28%	179	1,880,000	29%	188

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts
1				
2	SUMMER PERIOD		SUMMER 2012	
3				
4	Sendout Requirement (May, Oct)	595,878		
5	Currently Held Financial Contracts	260,000	44%	26
6	Planned Financial Contracts	0	0%	0
7	Total Hedged Volume	260,000	44%	26
8	Target Hedged Volume	240,000	40%	24
9	Projected Position Relative to Target Long/(Short)	20,000	3%	2
10				
11	WINTER PERIOD		WINTER 2012-13	
12				
13	Sendout Requirement	5,520,813		
14	Washington 10 Storage	2,206,374	40%	
15	Tennessee Storage	230,740	4%	
16	Fixed Price Physical Contracts	0	0%	
17	Currently Held Financial Contracts	0	0%	
18	Planned Financial Contracts	1,220,000	22%	122
19	Total Hedged Volume	3,657,114	66%	
20	Target Financial Hedge	3,860,000	70%	386
21	Projected Position Relative to Target Long/(Short)	-200,000	-4%	-20

Schedule 21

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

1 **Total Fixed Capacity Costs To Be Allocated**

Line		NUI Total
2		**NUI Total**
3	Pipeline Demand	$ 8,686,038
4	Storage Demand	$ 31,488,269
5	Peaking Demand	$ 1,812,610
6	Subtotal Demand	$ 41,986,917
7	Litigation Expense - PNGTS Invoices	$ 879,197
8	Capacity Release (Credit)	$ (313,490)
9	Asset Management (Credit)	$ (4,087,000)
10	Total Net Demand Costs	$ 38,465,624

11

12

13 **Proportional Responsibility (PR) Allocators**

14

15 **Allocation of Product and Pipeline Demand Costs (including Injections) to Months**

Line		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
16		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**
17	Design Year Pipeline Sendout	952,333	866,002	822,579	743,372	916,712	792,961	539,352	413,419	367,754	351,109	374,449	634,030	7,774,072
18	Rank	1	3	4	6	2	5	8	9	11	12	10	7	
19	% Max Month	100.00%	90.93%	86.38%	78.06%	96.26%	83.27%	56.63%	43.41%	38.62%	36.87%	39.32%	66.58%	
20	PR	3.74%	1.52%	0.78%	1.91%	2.66%	1.04%	1.65%	0.45%	0.16%	3.07%	0.07%	1.42%	18.48%
21	CumPR	18.48%	12.08%	10.56%	8.74%	14.74%	9.78%	5.41%	3.76%	3.23%	3.07%	3.30%	6.83%	100.00%
22	Product and Pipeline Demand Costs	$ 1,605,581	$ 1,049,431	$ 917,414	$ 759,421	$ 1,280,690	$ 849,878	$ 469,843	$ 326,267	$ 280,668	$ 266,866	$ 286,774	$ 593,206	$ 8,686,038

23

24 **Allocation of Storage Injection Fees to Months**

Line		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
25		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**
26	Storage Injection Volume	-	-	-	-	-	504,390	574,802	556,260	574,802	574,802	551,060	283,758	3,619,874
27	Design Year Pipeline Sendout	952,333	866,002	822,579	743,372	916,712	792,961	539,352	413,419	367,754	351,109	374,449	634,030	7,774,072
28	% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	38.9%	51.6%	57.4%	61.0%	62.1%	59.5%	30.9%	31.8%
29	Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 330,419	$ 242,396	$ 187,164	$ 171,160	$ 165,670	$ 170,749	$ 183,405	$ 1,450,964

30

31 **Allocation of Storage Demand Costs to Months**

Line		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
32		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**
33	Design Year Storage	-	654,361	1,042,725	956,652	685,269	203,848	-	-	-	-	-	-	3,542,855
34	Rank	6	4	1	2	3	5	6	6	6	6	6	6	
35	% Max Month	0.00%	62.75%	100.00%	91.75%	65.72%	19.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
36	PR	0.00%	10.80%	8.25%	13.01%	0.99%	3.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.97%
37	CumPR	0.00%	14.71%	36.97%	28.71%	15.70%	3.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
38	Storage Demand Costs	$ -	$ 4,632,318	$ 11,640,304	$ 9,041,051	$ 4,943,433	$ 1,231,163	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,488,269
39	Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 330,419	$ 242,396	$ 187,164	$ 171,160	$ 165,670	$ 170,749	$ 183,405	$ 1,450,964
40	TOTAL	$ -	$ 4,632,318	$ 11,640,304	$ 9,041,051	$ 4,943,433	$ 1,561,582	$ 242,396	$ 187,164	$ 171,160	$ 165,670	$ 170,749	$ 183,405	$ 32,939,234

41

42 **Allocation of Peaking Demand Costs to Months**

Line		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
43		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**
44		0.01	0.02	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.1	0.11	0.12	
44	Design Year Peaking Volumes	1,350	16,259	160,863	68,127	8,334	5,517	1,395	1,350	1,395	1,395	1,350	2,123	269,458
45		1,350	16,259	160,863	68,127	8,334	5,518	1,395	1,350	1,395	1,395	1,350	2,123	
45	Rank	12	3	1	2	4	5	9	11	8	7	10	6	
46	% Max Month	0.84%	10.11%	100.00%	42.35%	5.18%	3.43%	0.87%	0.84%	0.87%	0.87%	0.84%	1.32%	
47	PR	0.07%	1.64%	57.65%	16.12%	0.44%	0.42%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%	76.42%
48	CumPR	0.07%	2.65%	76.42%	18.77%	1.01%	0.57%	0.07%	0.07%	0.07%	0.07%	0.07%	0.15%	100.00%
49	Peaking Demand Costs	$ 1,268	$ 48,041	$ 1,385,218	$ 340,269	$ 18,276	$ 10,341	$ 1,324	$ 1,268	$ 1,324	$ 1,324	$ 1,268	$ 2,691	$ 1,812,610

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

1		
2		
3	Pipeline Demand	Schedule 5
4	Storage Demand	Schedule 5
5	Peaking Demand	Schedule 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	Schedule 5
9	Asset Management (Credit)	Schedule 5
10	Total Net Demand Costs	Sum LN 6 : LN 9
11		
12		
13	**Proportional Responsibility (PR) Allocators**	
14		
15	**Allocation of Product and Pipeline Demand Costs (including Injections) to Months**	
16		
17	Design Year Pipeline Sendout	Company Analysis
18	Rank	LN 17 Ranking
19	% Max Month	LN 17 / LN 17 MAX
20	PR	The difference between LN 19 for the month and LN 19 for next highest rank
21	CumPR	Cumulative Values, LN 20
22	Product and Pipeline Demand Costs	LN 21 * LN 3
23		
24	**Allocation of Storage Injection Fees to Months**	
25		
26	Storage Injection Volume	Company Analysis
27	Design Year Pipeline Sendout	LN 17
28	% of Deliveries Injected	LN 26 / Sum (LN 26 : LN 27)
29	Injection Fees	LN 28 * LN 22
30		
31	**Allocation of Storage Demand Costs to Months**	
32		
33	Design Year Storage	Company Analysis
34	Rank	LN 33 Ranking
35	% Max Month	LN 33 / LN 33 MAX
36	PR	The difference between LN 35 for the month and LN 35 for next highest rank
37	CumPR	Cumulative Values, LN 36
38	Storage Demand Costs	LN 37 * LN 4
39	Plus Injection Fees	LN 29
40	TOTAL	LN 38 + LN 39
41		
42	**Allocation of Peaking Demand Costs to Months**	
43		
44		
44	Design Year Peaking Volumes	Company Analysis
45		
45	Rank	Rank LN 44
46	% Max Month	LN 44 / LN 44 MAX
47	PR	The difference between LN 46 for the month and LN 46 for next highest rank
48	CumPR	Cumulative Values, LN 47
49	Peaking Demand Costs	LN 48 * LN 5

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

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
Pipeline & Product Demand	$ 1,605,581	$ 1,049,431	$ 917,414	$ 759,421	$ 1,280,690	$ 849,878	$ 469,843	$ 326,267	$ 280,668	$ 266,866	$ 286,774	$ 593,206	$ 8,686,038
Storage Incld Inj Fees	$ -	$ 4,632,318	$ 11,640,304	$ 9,041,051	$ 4,943,433	$ 1,561,582	$ 242,396	$ 187,164	$ 171,160	$ 165,670	$ 170,749	$ 183,405	$ 32,939,234
Peaking	$ 1,268	$ 48,041	$ 1,385,218	$ 340,269	$ 18,276	$ 10,341	$ 1,324	$ 1,268	$ 1,324	$ 1,324	$ 1,268	$ 2,691	$ 1,812,610
Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (330,419)	$ (242,396)	$ (187,164)	$ (171,160)	$ (165,670)	$ (170,749)	$ (183,405)	$ (1,450,964)
Less: Capacity Release	$ (62,698)	$ (62,698)	$ (62,698)	$ (62,698)	$ (62,698)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (313,490)
Less: Asset Mgmt	$ (681,167)	$ (681,167)	$ (681,167)	$ (681,167)	$ (681,167)	$ (681,167)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,087,000)
Total Demand	$ 862,984	$ 4,985,925	$ 13,199,071	$ 9,396,876	$ 5,498,534	$ 1,410,215	$ 471,167	$ 327,535	$ 281,992	$ 268,190	$ 288,042	$ 595,897	$ 37,586,427

Capacity Cost Allocator based on Design Year Firm Sendout

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
Therms													
Maine	519,106	831,371	1,055,929	919,519	843,747	535,094	284,050	220,889	200,842	195,522	204,694	353,883	6,164,646
New Hampshire	434,577	705,251	970,238	848,632	766,568	467,232	256,697	193,880	168,307	156,982	171,105	282,270	5,421,739
Total	953,683	1,536,622	2,026,167	1,768,151	1,610,315	1,002,326	540,747	414,769	369,149	352,504	375,799	636,153	11,586,385

Percentage of Total	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
Maine	54.43%	54.10%	52.11%	52.00%	52.40%	53.39%	52.53%	53.26%	54.41%	55.47%	54.47%	55.63%	52.62%
New Hampshire	45.57%	45.90%	47.89%	48.00%	47.60%	46.61%	47.47%	46.74%	45.59%	44.53%	45.53%	44.37%	47.38%
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%

Allocation of Demand Costs by Division

Maine	$469,737	$2,697,575	$6,878,644	$4,886,803	$2,881,033	$752,846	$247,500	$174,432	$153,423	$148,756	$156,893	$331,489	$19,779,133
New Hampshire	$393,247	$2,288,350	$6,320,427	$4,510,073	$2,617,500	$657,368	$223,667	$153,103	$128,569	$119,434	$131,148	$264,408	$17,807,295
Total	$ 862,984	$ 4,985,925	$ 13,199,071	$ 9,396,876	$ 5,498,534	$ 1,410,215	$ 471,167	$ 327,535	$ 281,992	$ 268,190	$ 288,042	$ 595,897	$ 37,586,427

Detailed Allocation of Demand Costs by Division

Maine	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	
Pipeline & Product Demand	$ 873,945	$ 567,782	$ 478,107	$ 394,933	$ 671,035	$ 453,709	$ 246,805	$ 173,756	$ 152,702	$ 148,022	$ 156,203	$ 329,992	$ 4,646,992	53.50%
Storage Incld Injection Fees	$ -	$ 2,506,260	$ 6,066,299	$ 4,701,758	$ 2,590,181	$ 833,654	$ 127,329	$ 99,676	$ 93,123	$ 91,891	$ 93,005	$ 102,026	$ 17,305,202	52.54%
Peaking	$ 690	$ 25,992	$ 721,901	$ 176,955	$ 9,576	$ 5,521	$ 695	$ 675	$ 720	$ 734	$ 690	$ 1,497	$ 945,647	52.17%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (176,395)	$ (127,329)	$ (99,676)	$ (93,123)	$ (91,891)	$ (93,005)	$ (102,026)	$ (783,445)	
Capacity Release (Credit)	$ (34,128)	$ (33,922)	$ (32,675)	$ (32,606)	$ (32,851)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (166,182)	53.01%
Asset Management (Credit)	$ (370,771)	$ (368,537)	$ (354,987)	$ (354,238)	$ (356,907)	$ (363,642)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,169,082)	53.07%
Total Allocated Demand	$ 469,737	$ 2,697,575	$ 6,878,644	$ 4,886,803	$ 2,881,033	$ 752,846	$ 247,500	$ 174,432	$ 153,423	$ 148,756	$ 156,893	$ 331,489	$ 19,779,133	52.62%

New Hampshire	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	
Pipeline & Product Demand	$ 731,636	$ 481,649	$ 439,307	$ 364,487	$ 609,654	$ 396,169	$ 223,038	$ 152,511	$ 127,965	$ 118,845	$ 130,571	$ 263,214	$ 4,039,046	46.50%
Storage Incld Injection Fees	$ -	$ 2,126,058	$ 5,574,005	$ 4,339,293	$ 2,353,252	$ 727,928	$ 115,068	$ 87,488	$ 78,038	$ 73,778	$ 77,744	$ 81,379	$ 15,634,031	47.46%
Peaking	$ 578	$ 22,049	$ 663,317	$ 163,314	$ 8,700	$ 4,820	$ 629	$ 593	$ 604	$ 590	$ 577	$ 1,194	$ 866,963	47.83%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (154,024)	$ (115,068)	$ (87,488)	$ (78,038)	$ (73,778)	$ (77,744)	$ (81,379)	$ (667,519)	
Capacity Release	$ (28,570)	$ (28,776)	$ (30,023)	$ (30,092)	$ (29,846)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (147,308)	46.99%
Asset Management - PNGTS (Credit)	$ (310,396)	$ (312,630)	$ (326,179)	$ (326,929)	$ (324,260)	$ (317,524)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,917,918)	46.93%
PNGTS Expense	$ 69,146	$ 69,146	$ 69,146	$ 69,146	$ 69,146	$ 69,146	$ -	$ -	$ -	$ -	$ -	$ -	$ 414,873	
Total Allocated Demand	$ 393,247	$ 2,288,350	$ 6,320,427	$ 4,510,073	$ 2,617,500	$ 657,368	$ 223,667	$ 153,103	$ 128,569	$ 119,434	$ 131,148	$ 264,408	$ 17,807,295	47.38%

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

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

Schedule 22

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	OFF-PEAK
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	260,938	211,239	203,111	204,032	220,001	332,146	4,387,843	1,431,466
3	Total Storage	0	0	0	0	0	0	2,523,077	0
4	Total Peaking	1,395	1,350	1,395	1,395	1,350	1,395	20,298	8,280
5	Subtotal	262,333	212,589	204,506	205,427	221,351	333,541	6,931,218	1,439,746
6	Less Interruptible - Maine	0	0	0	0	0	0	0	0
7	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
8	Total Firm Supply	262,333	212,589	204,506	205,427	221,351	333,541	6,931,218	1,439,746
9	Total Firm Pipeline Sendout	260,938	211,239	203,111	204,032	220,001	332,146	4,387,843	1,431,466
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 801,396	$ 666,854	$ 654,543	$ 664,562	$ 719,858	$ 1,108,708	$ 19,004,569	$ 4,615,921
12	NYMEX Price Used for Forecast	$4.015	$4.055	$4.098	$4.121	$4.121	$4.155		
13	NYMEX Price Used for Update	$2.712	$2.802	$2.870	$2.904	$2.914	$2.967		
14	Increase/(Decrease) NYMEX Price	-$1.303	-$1.253	-$1.228	-$1.217	-$1.207	-$1.188		
15	Increase/(Decrease) in Pipeline Costs	$ (340,002)	$ (264,682)	$ (249,420)	$ (248,307)	$ (265,541)	$ (394,589)		
16	Total Updated Pipeline Costs	$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	$ 19,960,193	$ 2,853,380
17									
18	Total Pipeline	$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	$ 19,960,193	$ 2,853,380
19	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,426,035	$ -
20	Total Peaking	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 121,645	$ 41,916
21	Subtotal	$ 468,859	$ 409,203	$ 412,223	$ 423,213	$ 460,937	$ 720,863	$ 31,507,872	$ 2,895,296
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	12	-	-	-	-	14	122	26
26	Average Purchase Price	$ 4.002	$ -	$ -	$ -	$ -	$ 4.207		
27	NYMEX Price Used for Forecast	$ 4.015	$ 4.055	$ 4.098	$ 4.121	$ 4.121	$ 4.155		
28	NYMEX Price Used for Update	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967		
29	Increase/(Decrease) NYMEX Price	$ (1.303)	$ (1.253)	$ (1.228)	$ (1.217)	$ (1.207)	$ (1.188)		
30	Futures Hedging (Gain)/Loss - Allocate	$ 154,800	$ -	$ -	$ -	$ -	$ 173,600	$ 798,580	$ 328,400
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 4.015	$ 4.055	$ 4.098	$ 4.121	$ 4.121	$ 4.155		
35	NYMEX Price Used for Update	$ 2.712	$ 2.802	$ 2.870	$ 2.904	$ 2.914	$ 2.967		
36	Increase/(Decrease) NYMEX Price	$ (1.303)	$ (1.253)	$ (1.228)	$ (1.217)	$ (1.207)	$ (1.188)		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	$ 19,960,193	$ 2,853,380
41	Average Supply Cost ($/MMBtu)	$ 1.768	$ 1.904	$ 1.995	$ 2.040	$ 2.065	$ 2.150		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	$ 19,960,193	$ 2,853,380
46	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,426,035	$ -
47	Total Peaking	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 121,645	$ 41,916
48	Firm Sales Variable Costs Excld Hedge	$ 468,859	$ 409,203	$ 412,223	$ 423,213	$ 460,937	$ 720,863	$ 31,507,872	$ 2,895,296
49	Plus Hedging (Gain)/Loss	$ 154,800	$ -	$ -	$ -	$ -	$ 173,600	$ 798,580	$ 328,400
50	Total Firm Sales Variable Costs	$ 623,659	$ 409,203	$ 412,223	$ 423,213	$ 460,937	$ 894,463	$ 32,306,452	$ 3,223,696

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	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Company Analysis
7	Less Interruptible - New Hampshire	Company Analysis
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Schedule 6A, page 1
12	NYMEX Price Used for Forecast	Attachment to Schedule 6B, page 1
13	NYMEX Price Used for Update	Attachment to Schedule 6B, page 1
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Schedule 6A, page 1
20	Total Peaking	Schedule 6A, page 1
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Schedule 7
26	Average Purchase Price	Schedule 7
27	NYMEX Price Used for Forecast	Line 14
28	NYMEX Price Used for Update	Schedule 7
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Schedule 7
33	Average Purchase Price	Schedule 7
34	NYMEX Price Used for Forecast	Line 14
35	NYMEX Price Used for Update	Schedule 7
36	Increase/(Decrease) NYMEX Price	LN 35 - LN 34
37	Futures Hedging (Gain)/Loss (NH ONLY)	(LN 33 - LN 34 - LN 36) * LN 32*10,000
38		
39	Interruptible Cost Estimate	
40	Variable Pipeline Costs Excld Hedges	LN 16
41	Average Supply Cost ($/MMBtu)	LN 40 / LN 2
42	Interruptible Cost - Maine	LN 41 * LN 6
43	Interruptible Cost - New Hampshire	LN 41 * LN 7
44		
45	Firm Sales Pipeline Commodity Excld Hedge	LN 40 - LN 42 - LN 43
46	Total Storage	LN 19
47	Total Peaking	LN 20
48	Firm Sales Variable Costs Excld Hedge	Sum LN 45 : LN 47
49	Plus Hedging (Gain)/Loss	LN 30
50	Total Firm Sales Variable Costs	LN 48 + LN 49

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	OFF-PEAK
Maine	126,349	103,170	97,722	96,784	103,614	158,051	3,288,563	685,690
New Hampshire	135,986	109,421	106,786	108,645	117,739	175,492	3,642,681	754,069
Total	262,335	212,591	204,508	205,429	221,353	333,543	6,931,244	1,439,759
Percentage of Total								
Maine	48.16%	48.53%	47.78%	47.11%	46.81%	47.39%	47.45%	47.63%
New Hampshire	51.84%	51.47%	52.22%	52.89%	53.19%	52.61%	52.55%	52.37%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL	OFF-PEAK
Maine								
Firm Sales Pipeline Commodity Excld Hedge	$ 222,222	$ 195,173	$ 193,584	$ 196,111	$ 212,663	$ 338,389	$ 9,478,241	$ 1,358,142
Hedging (Gains) Losses	$ 74,557	$ -	$ -	$ -	$ -	$ 82,261	$ 379,442	$ 156,818
Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,404,736	$ -
Peaking	$ 3,595	$ 3,412	$ 3,392	$ 3,278	$ 3,099	$ 3,196	$ 57,848	$ 19,972
Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 300,374	$ 198,585	$ 196,976	$ 199,389	$ 215,762	$ 423,846	$ 15,320,267	$ 1,534,932
Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,444	$ -
Total Maine Variable Costs	$ 300,374	$ 198,585	$ 196,976	$ 199,389	$ 215,762	$ 423,846	$ 15,325,710	$ 1,534,932
New Hampshire								
Firm Sales Pipeline Commodity Excld Hedge	$ 239,172	$ 206,999	$ 211,539	$ 220,144	$ 241,654	$ 375,730	$ 10,481,952	$ 1,495,238
Hedging (Gains) Losses	$ 80,243	$ -	$ -	$ -	$ -	$ 91,339	$ 419,138	$ 171,582
Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,021,299	$ -
Peaking	$ 3,869	$ 3,619	$ 3,707	$ 3,680	$ 3,521	$ 3,548	$ 63,797	$ 21,944
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 16,986,186	$ 1,688,765
New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,048	$ -
Total New Hampshire Variable Costs	$ 323,284	$ 210,617	$ 215,246	$ 223,824	$ 245,175	$ 470,617	$ 16,992,234	$ 1,688,765
Northern Utilities								
Firm Sales Pipeline Commodity Excld Hedge	$ 461,395	$ 402,172	$ 405,124	$ 416,255	$ 454,317	$ 714,119	$ 19,960,193	$ 2,853,380
Hedging (Gains) Losses	$ 154,800	$ -	$ -	$ -	$ -	$ 173,600	$ 798,580	$ 328,400
Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,426,035	$ -
Peaking	$ 7,464	$ 7,031	$ 7,099	$ 6,958	$ 6,620	$ 6,744	$ 121,645	$ 41,916
Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 623,659	$ 409,203	$ 412,223	$ 423,213	$ 460,937	$ 894,463	$ 32,306,452	$ 3,223,696
Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,492	$ -
Total Northern Variable Costs	$ 623,659	$ 409,203	$ 412,223	$ 423,213	$ 460,937	$ 894,463	$ 32,317,944	$ 3,223,696

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51	**Commodity Allocation Factors**	
52	Firm Sales Sendout for Normal Winter, MMBtu	
53		
54	Maine	Company Analysis
55	New Hampshire	NH Schedule 10B, LN 33 / 10
56	Total	LN 54 + LN 55
57		
58	**Percentage of Total**	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60
62		
63	**Commodity Allocation by Jurisdiction**	
64	**Maine**	
65	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 59
66	Hedging (Gains) Losses	LN 30 * LN 59
67	Storage	LN 46 * LN 59
68	Peaking	LN 47 * LN 59
69	Maine Interruptible	LN 42
70	Total Maine Commodity Costs	Sum LN 65 : LN 69
71	Maine Inventory Finance Costs	LN 112
72	Total Maine Variable Costs	LN 70 + LN 71
73	**New Hampshire**	
74	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60
76	Storage	LN 46 * LN 60
77	Peaking	LN 47 * LN 60
78	New Hampshire Interruptible	LN 43
79	Total New Hampshire Commodity Costs	Sum LN 74 : LN 78
80	New Hampshire Inventory Finance Costs	LN 117
81	Total New Hampshire Variable Costs	LN 79 + LN 80
82	**Northern Utilities**	
83	Firm Sales Pipeline Commodity Excld Hedge	LN 65 + LN 74
84	Hedging (Gains) Losses	LN 66 + LN 75
85	Storage	LN 67 + LN 76
86	Peaking	LN 68 + LN 77
87	Northern Interruptible	LN 69 + LN 78
88	Total Northern Commodity Costs	LN 70 + LN 79
89	Northern Inventory Finance Costs	LN 71 + LN 80
90	Total Northern Variable Costs	LN 88 + LN 89
91		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

Col A	Col H	Col I	Col J	Col K	Col L	Col M	Col N	Col P
Inventory Finance Charge	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**TOTAL**	**OFF-PEAK**
Storage	$ 150	$ 450	$ 757	$ 1,042	$ 1,168	$ 1,168	$ 10,308	$ 4,735
Peaking	$ 96	$ 93	$ 91	$ 89	$ 87	$ 86	$ 1,184	$ 543
Total	$ 246	$ 543	$ 848	$ 1,131	$ 1,255	$ 1,254	$ 11,492	$ 5,278
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 119	$ 264	$ 405	$ 533	$ 588	$ 594	$ 5,444	$ 2,502
New Hampshire	$ 128	$ 280	$ 443	$ 598	$ 668	$ 660	$ 6,048	$ 2,776
Total	$ 246	$ 543	$ 848	$ 1,131	$ 1,255	$ 1,254	$ 11,492	$ 5,278
Inventory Finance Charge Allocation by Month								
Maine								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,031,904	0
Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,444	$ -
New Hampshire								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,256,218	0
Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,048	$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

92 **Northern Utilities**
93 **Simplified Market Based Allocator (MBA) Calculations**
94 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**
95
96
97

LN		
98	**Inventory Finance Charge**	
99	Storage	"Schedule 14 - Carrying Costs"
100	Peaking	"Schedule 14 - Carrying Costs"
101	Total	Sum LN 99 : LN 100
102		
103	**Inventory Finance Charge Allocation by Jurisdiction**	
104	Maine	LN 101 * LN 59
105	New Hampshire	LN 101 * LN 60
106	Total	Sum LN 104 : LN 105
107		
108	**Inventory Finance Charge Allocation by Month**	
109	**Maine**	
110	Firm Sales Remaining Sendout	Company Analysis
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111
113		
114	**New Hampshire**	
115	Firm Sales Remaining Sendout	NH Schedule 10B, LN 80 / 10
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

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

		Winter	Summer	Total	
1	Demand	$ 13,187,814	$ 858,736	$ 14,046,550	Schedule 1A, LN 80
2	Commodity	$ 15,303,469	$ 1,688,765	$ 16,992,234	Schedule 1B, LN 43
3	Total	$ 28,491,283	$ 2,547,501	$ 31,038,783	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,614,458	7,466,573	36,081,030	Schedule 10B, LN 12 * 10
6	Forecasted Residential Sales (Therms)	13,532,174	3,440,019	16,972,192	Schedule 10B, LN 3 * 10
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.4609	$0.1150		LN 1 / LN 5
9	Average Commodity Rate	$0.5348	$0.2262		LN 2 / LN 5
10	Average Rate	$0.9957	$0.3412		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 6,061,151	$ 395,027	$ 6,456,178	Schedule 10C, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,236,700	$ 395,602	$ 6,632,302	LN 8 * LN 6
15	**Demand Reallocation:**	$ (175,549)	$ (575)	$ (176,124)	LN 13 - LN 14
16	**HLF Allocation**	$ (21,599)	$ (158)	$ (21,757)	LN 15 / LN 20
17	**LLF Allocation**	$ (153,949)	$ (417)	$ (154,366)	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	12.30%	27.46%		Schedule 10A, LN 173
21	LLF	87.70%	72.54%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 7,229,790	$ 778,139	$ 8,007,930	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 7,237,223	$ 778,132	$ 8,015,355	LN 18 * LN 16
25	**Commodity Reallocation:**	$ (7,432)	$ 7	$ (7,425)	LN 23 - LN 24
26	**HLF Allocation**	$ (1,338)	$ 3	$ (1,335)	LN 25 / LN 30
27	**LLF Allocation**	$ (6,094)	$ 4	$ (6,090)	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	18.01%	43.72%		Schedule 10C, LN 143
31	LLF	81.99%	56.28%		Schedule 10C, LN 144

Schedule 24

Provided in Winter 2011-12 Cost-of-Gas Filing