Summary

Unitil
Northern Utilities, Inc.

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

Summary Schedule

New Hampshire Division
Period Covered: May 1, 2011 - October 31, 2011

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas:**		
3	Demand Costs:	$ 497,292	
4	Supply Costs:	$ 3,441,521	
5			
6	**Storage & Peaking Gas:**		
7	Demand, Capacity:	$ 701,178	
8	Commodity Costs:	$ 25,185	
9			
10	**Hedging (Gain)/Loss**	$ 72,585	
11			
12	**Interruptible Included Above**	$ -	
13			
14	**Capacity Release**	$ -	
15			
16	**Adjustment for Actual Costs**	$ -	
17			
18	**Total Anticipated Direct Cost of Gas**		$ 4,737,762
19			
20	**ANTICIPATED INDIRECT COST OF GAS**		
21	**Adjustments:**		
22	Prior Period Under/(Over) Collection	$ 124,276	
23	NHPUC Consultant Costs	$ 28,990	
24	Interest	$ 2,150	
25	Refunds	$ -	
26	Interruptible Margins	$ -	
27	Total Adjustments		$ 155,415
28			
29	**Working Capital:**		
30	Total Anticipated Direct Cost of Gas	$ 4,737,762	
31	Working Capital Percentage (6.333[lag days]/365* prime rate*)	0.056%	
32	Working Capital Allowance	$ 2,670	
33	Plus: Working Capital Reconciliation	$ (7,494)	
34			
35	Total Working Capital Allowance		$ (4,824)
36			
37	**Bad Debt:**		
38	Total Anticipated Direct Cost of Gas	$ 4,737,762	
39	Plus: Prior Period Under/(Over) Collection	$ 124,276	
40	Plus: Total Working Capital	$ (4,824)	
41	Subtotal	$ 4,857,215	
42			
43	Bad Debt Percentage	0.450%	
44	Bad Debt Allowance	$ 21,857	
45	Plus: Bad Debt Reconciliation (Acct 182.22)	$ 3,159	
46	Total Bad Debt Allowance		$ 25,016
47			
48	**Local Production and Storage Capacity**		$ -
49			
50	**Miscellaneous Overhead-20.89% of $124,297**		$ 25,964
51			
52	**Total Anticipated Indirect Cost of Gas**		$ 201,572
53			
54	**Total Cost of Gas**		$ 4,939,335
55			

(*) Prime Rate is 3.25%

NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: May 1, 2011 - October 31, 2011

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 4,737,762		
Projected Prorated Sales (05/01/11 - 10/31/11)		7,400,642		
Direct Cost of Gas Rate			$ 0.6402	per therm
Demand Cost of Gas Rate		$ 1,198,470	$ 0.1619	per therm
Commodity Cost of Gas Rate		$ 3,539,292	$ 0.4782	per therm
Total Direct Cost of Gas Rate		$ 4,737,762	$ 0.6401	per therm
Total Anticipated Indirect Cost of Gas		$ 201,572		
Projected Prorated Sales (05/01/11 - 10/31/11)		7,400,642		
Indirect Cost of Gas			$ 0.0272	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/11			**$ 0.6673**	**per therm**
RESIDENTIAL COST OF GAS RATE - 05/01/11		**COGwr**	**$ 0.6673**	**per therm**
		Maximum (COG+25%)	**$ 0.8341**	
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/11		**COGwl**	**$ 0.5975**	**per therm**
		Maximum (COG+25%)	**$ 0.7469**	
C&I HLF Demand Costs Allocated per SMBA	$ 163,969			
PLUS: Residential Demand Reallocation to C&I HLF	$ 9,244			
C&I HLF Total Adjusted Demand Costs	$ 173,212			
C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	1,834,095			
Demand Cost of Gas Rate	**$ 0.0944**			
C&I HLF Commodity Costs Allocated per SMBA	$ 873,408			
PLUS: Residential Commodity Reallocation to C&I HLF	$ (553)			
C&I HLF Total Adjusted Commodity Costs	$ 872,856			
C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	1,834,095			
Commodity Cost of Gas Rate	**$ 0.4759**			
Indirect Cost of Gas	**$ 0.0272**			
Total C&I HLF Cost of Gas Rate	**$ 0.5975**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/11		**COGwh**	**$ 0.7234**	**per therm**
		Maximum (COG+25%)	**$ 0.9043**	
C&I LLF Demand Costs Allocated per SMBA	$ 468,664			
PLUS: Residential Demand Reallocation to C&I LLF	$ 26,421			
C&I LLF Total Adjusted Demand Costs	$ 495,086			
C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	2,291,857			
Demand Cost of Gas Rate	**$ 0.2160**			
C&I LLF Commodity Costs Allocated per SMBA	$ 1,101,176			
PLUS: Residential Commodity Reallocation to C&I LLF	$ (697)			
C&I LLF Total Adjusted Commodity Costs	$ 1,100,479			
C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	2,291,857			
Commodity Cost of Gas Rate	**$ 0.4802**			
Indirect Cost of Gas	**$ 0.0272**			
Total C&I LLF Cost of Gas Rate	**$ 0.7234**			

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2011 - October 31, 2011

	Column A	Column D
1	**ANTICIPATED DIRECT COST OF GAS**	
2	**Purchased Gas:**	
3	Demand Costs:	Schedule 1A, LN 71
4	Supply Costs:	Schedule 1B, LN 15
5		
6	**Storage & Peaking Gas:**	
7	Demand, Capacity:	Schedule 1A, LN 73
8	Commodity Costs:	Schedule 1B, LN 16 + Schedule 1B, LN 17
9		
10	**Hedging (Gain)/Loss**	Schedule 1B, LN 15
11		
12	**Interruptible Included Above**	- (Schedule 1B, LN 22)
13		
14	**Capacity Release**	- (Schedule 1A, LN 76)
15		
16	**Adjustment for Actual Costs**	
17		
18	**Total Anticipated Direct Cost of Gas**	Sum (LN 3 : LN 16)
19		
20	**ANTICIPATED INDIRECT COST OF GAS**	
21	**Adjustments:**	
22	Prior Period Under/(Over) Collection	Schedule 3, LN 108: October
23	NHPUC Consultant Costs	
24	Interest	Schedule 3, LN 115: Total
25	Refunds	Company Analysis
26	Interruptible Margins	- (Schedule 1A, LN 77)
27	Total Adjustments	Sum (LN 22 : LN 26)
28		
29	**Working Capital:**	
30	Total Anticipated Direct Cost of Gas	LN 18
31	Working Capital Percentage (6.333[lag days]/365* prime rate*)	3rd Rev. Pg 21 IV COG Clause 6.1
32	Working Capital Allowance	LN 30 * LN 31
33	Plus: Working Capital Reconciliation	Schedule 3, LN 85: October 2010 Summer Reconciliation
34		
35	Total Working Capital Allowance	Sum (LN 32 : LN 33)
36		
37	**Bad Debt:**	
38	Total Anticipated Direct Cost of Gas	LN 18
39	Plus: Prior Period Under/(Over) Collection	Schedule 3, LN 108: October
40	Plus: Total Working Capital	LN 35
41	Subtotal	Sum (LN 38 : LN 40)
42		
43	Bad Debt Percentage	3rd Rev. Pg 21 IV COG Clause 6.1
44	Bad Debt Allowance	LN 43 * LN 41
45	Plus: Bad Debt Reconciliation (Acct 182.22)	Schedule 3, LN 96: October
46	Total Bad Debt Allowance	LN 44 + LN 45
47		
48	**Local Production and Storage Capacity**	Schedule 1A, LN 84
49		
50	**Miscellaneous Overhead-20.89% of $124,297**	Schedule 1A, LN 83
51		
52	**Total Anticipated Indirect Cost of Gas**	Sum (LN 27 : LN 50)
53		
54	**Total Cost of Gas**	LN 52 + LN 18
55		

(*) Prime Rate is 3.25%

NORTHERN UTILITIES, INC.

LN	Column A	Column D
56		
57	CALCULATION OF FIRM SALES COST OF GAS RATE	
58	Period Covered: May 1, 2011 - October 31, 2011	
59		
60	**Column A**	**Column D**
61		
62	Total Anticipated Direct Cost of Gas	LN 18
63	Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
64	**Direct Cost of Gas Rate**	LN 62 / LN 63
65		
66	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 14)
67	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8 , LN 10 , LN 12)
68	**Total Direct Cost of Gas Rate**	SUM (LN 66 : LN 67)
69		
70	Total Anticipated Indirect Cost of Gas	LN 52
71	Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
72	**Indirect Cost of Gas**	LN 70 / LN 71
73		
74		
75	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/11**	LN 68 + LN 72
76		
77	**RESIDENTIAL COST OF GAS RATE - 05/01/11**	Company Analysis
78		LN 77 * 1.25
79		
80		
81	**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/11**	Company Analysis
82		LN 81 * 1.25
83		
84	C&I HLF Demand Costs Allocated per SMBA	Schedule 10A, LN 169
85	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 23, LN 16
86	C&I HLF Total Adjusted Demand Costs	Sum (LN 84 : LN 85)
87	C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
88	**Demand Cost of Gas Rate**	LN 86 / LN 87
89		
90	C&I HLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 139
91	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 23, LN 26
92	C&I HLF Total Adjusted Commodity Costs	Sum (LN 90 : LN 91)
93	C&I HLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
94	**Commodity Cost of Gas Rate**	LN 92 / LN 93
95		
96	**Indirect Cost of Gas**	LN 72
97		
98	**Total C&I HLF Cost of Gas Rate**	Sum (LN 88, LN 94, LN 96)
99		
100		
101	**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/11**	Company Analysis
102		LN 101 * 1.25
103		
104	C&I LLF Demand Costs Allocated per SMBA	Schedule 10A, LN 170
105	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 23, LN 17
106	C&I LLF Total Adjusted Demand Costs	Sum (LN 104 : LN 105)
107	C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
108	**Demand Cost of Gas Rate**	LN 106 / LN 107
109		
110	C&I LLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 140
111	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 23, LN 27
112	C&I LLF Total Adjusted Commodity Costs	Sum (LN 110 : LN 111)
113	C&I LLF Projected Prorated Sales (05/01/11 - 10/31/11)	Company Analysis
114	**Commodity Cost of Gas Rate**	LN 112 / LN 113
115		
116	**Indirect Cost of Gas**	LN 72
117		
118	**Total C&I LLF Cost of Gas Rate**	Sum (LN 108, LN 114, LN 116)

Schedule 1A

Unitil
Northern Utilities, Inc.

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	$ 3,231,219
3	Storage	$ 14,905,160
4	Peaking	$ 2,847,287
5	Total Gross Demand Cost	$ 20,983,666
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,979,810
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 20,983,666
9	Capacity Assignment as % of Total Gross Demand Cost	14.20%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 458,853
14	Storage	$ 2,116,625
15	Peaking	$ 404,332
16	Total Capacity Assignment Credit	$ 2,979,810
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,772,366
21	Storage	$ 12,788,535
22	Peaking	$ 2,442,955
23	Total Net Demand Cost (Less Capacity Assignment)	$ 18,003,856
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,489
28	Less 14.20% NH Transp. Capacity Assignment	(1,632)
29	Net Pipeline MDQ	9,858
30		
31	Net Pipeline MDQ	9,858
32	Less: Firm Sales Base Use	2,895
33	Remaining Pipeline MDQ	6,962
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$281.24
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,772,366
40	Less: Base Pipeline Use	$ 814,306
41	Remaining Pipeline Use	$ 1,958,060

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	
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 DEI**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 14.20% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

All Months	Nov	Dec	Jan	Feb	Mar	Apr
Remaining Load for All Months	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209
Rank	6	4	1	2	3	5
% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
PR	3.91%	6.85%	15.73%	2.32%	3.20%	0.51%
CumPR	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%

Peak Months Only	Nov	Dec	Jan	Feb	Mar	Apr
Remaining Load for Peak Months Only	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209
Rank	6	4	1	2	3	5
% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
PR	6.67%	6.85%	15.73%	2.32%	3.20%	0.51%
CumPR	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

DEMAND COST PR ALLOCATORS

	Nov	Dec	Jan	Feb	Mar	Apr
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
Pipeline - Remaining	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%
Storage & Peaking	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%
Capacity Release	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%
Interr. Margins & Off Sys Sales	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	Dec	Jan	Feb	Mar	Apr
Pipeline - Base	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 67,859
Pipeline - Remaining	$ 115,650	$ 259,896	$ 676,080	$ 368,034	$ 322,579	$ 125,683
Total Pipeline	$ 183,508	$ 327,755	$ 743,939	$ 435,893	$ 390,438	$ 193,542
Storage & Peaking	$ 899,623	$ 2,021,696	$ 5,259,137	$ 2,862,887	$ 2,509,297	$ 977,671
Less Credits to Demand Cost						
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 117,579	$ 247,371	$ 621,852	$ 344,673	$ 303,773	$ 126,607
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
Total Direct Demand Costs	$ 965,553	$ 2,102,080	$ 5,381,224	$ 2,954,106	$ 2,595,962	$ 1,044,606

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

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

NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT
(Based on NH Firm Sales Sendout for Remaining Temperatur

All Months	May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
Remaining Load for All Months	764,485	190,519	28,120	90,665	282,509	920,625	25,432,233	23,155,310	2,276,922
Rank	8	10	12	11	9	7			
% Max Month	13.75%	3.43%	0.51%	1.63%	5.08%	16.56%			
PR	1.08%	0.18%	0.04%	0.10%	0.18%	0.40%	34.53%		
CumPR	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%

Peak Months Only	Total	Winter	Summer
Remaining Load for Peak Months Only	23,155,310		
Rank			
% Max Month			
PR	35.30%		
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	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
Storage & Peaking	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	95.40%	4.60%
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	Winter	Summer
Pipeline - Base	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 814,306	$ 407,153	$ 407,153	50.00%	50.00%
Pipeline - Remaining	$ 31,168	$ 6,346	$ 825	$ 2,828	$ 9,946	$ 39,025	$ 1,958,060	$ 1,867,921	$ 90,139	95.40%	4.60%
Total Pipeline	$ 99,027	$ 74,205	$ 68,684	$ 70,687	$ 77,805	$ 106,884	$ 2,772,366	$ 2,275,074	$ 497,292	82.06%	17.94%
Storage & Peaking	$ 242,453	$ 49,362	$ 6,421	$ 22,001	$ 77,369	$ 303,573	$ 15,231,489	$ 14,530,311	$ 701,178	95.40%	4.60%
Less Credits to Demand Cost											
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$1,761,855	$ 1,761,855	$ -	100.00%	0.00%
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Direct Demand Costs	$ 341,480	$ 123,567	$ 75,105	$ 92,688	$ 155,174	$ 410,457	$ 16,242,000	$ 15,043,530	$ 1,198,470	92.62%	7.38%

	Total	Winter	Summer	Winter	Summer
Indirect Demand Costs/(Credits)					
Miscellaneous Overhead	$ 124,297	$ 98,333	$ 25,964	79.11%	20.89%
Local Production & Storage	$ 686,673	$ 686,673	$ -	100.00%	0.00%
Subtotal	$ 810,970	$ 785,006	$ 25,964	96.80%	3.20%

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

LN	Description	Source / Calculation
42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT**	
43	(Based on NH Firm Sales Sendout for Remaining Temperatur	
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

Schedule 1B

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

Line		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
	Supply Volumes - Therms							
1	New Hampshire Sales Pipeline	1,654,474	1,051,622	826,747	952,582	1,143,989	1,810,979	7,440,393
2	New Hampshire Sales Storage	0	0	0	0	0	0	0
3	New Hampshire Sales Peaking	7,586	7,518	8,283	7,538	7,141	7,221	45,287
4	Total New Hampshire Firm Sales Sendout	1,662,060	1,059,140	835,030	960,120	1,151,130	1,818,200	7,485,680
5								
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0
7								
8	Total Firm Sendout	1,662,060	1,059,140	835,030	960,120	1,151,130	1,818,200	7,485,680
9	Total Firm Sales	1,645,185	1,046,679	825,723	948,437	1,136,884	1,797,734	7,400,642
10	Difference (LAUF & Company Use)	16,875	12,461	9,307	11,683	14,246	20,466	85,038
11	Percent Difference	1.02%	1.18%	1.11%	1.22%	1.24%	1.13%	1.14%
12								
13	**Variable Costs**							
14	New Hampshire Sales Pipeline Commodity	$ 743,740	$ 476,107	$ 380,786	$ 444,065	$ 535,555	$ 861,268	$ 3,441,521
15	New Hampshire Hedging (Gains) Losses	$ 45,984	$ -	$ -	$ -	$ -	$ 26,602	$ 72,585
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	New Hampshire Total Peaking	$ 3,872	$ 3,993	$ 4,561	$ 4,282	$ 4,164	$ 4,314	$ 25,185
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Total New Hampshire Sales Variable Costs	$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 3,539,292
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 747,612	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 865,581	$ 3,466,707
21								$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 3,539,292
24								
25	**Supply Cost/Therm**							
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.4495	$ 0.4527	$ 0.4606	$ 0.4662	$ 0.4681	$ 0.4756	$ 0.4625
27	New Hampshire Hedging (Gains) Losses	$ 0.0278	$ -	$ -	$ -	$ -	$ 0.0147	$ 0.0098
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.5104	$ 0.5311	$ 0.5506	$ 0.5681	$ 0.5831	$ 0.5973	$ 0.5561
30	New Hampshire Inventory Finance Costs per Dth Stor and F	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.4775	$ 0.4533	$ 0.4615	$ 0.4670	$ 0.4689	$ 0.4907	$ 0.4728
32								
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34								
35	**Commodity Costs**							
36	Base Commodity, therms	897,575	868,621	806,910	869,455	868,621	897,575	5,208,758
37	Base Commodity Cost Excld Hedging	$ 403,489	$ 393,256	$ 371,649	$ 405,314	$ 406,642	$ 426,870	$ 2,407,221
38	Base Hedging Commodity Cost	$ 24,947	$ -	$ -	$ -	$ -	$ 13,185	$ 38,131
39	Remaining Commodity Excld Hedging	$ 344,123	$ 86,844	$ 13,697	$ 43,034	$ 133,077	$ 438,711	$ 1,059,486
40	Remaining Hedging Commodity	$ 21,037	$ -	$ -	$ -	$ -	$ 13,417	$ 34,454
41	Total Commodity Excld Hedging	$ 747,612	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 865,581	$ 3,466,707
42	Total Hedging	$ 45,984	$ -	$ -	$ -	$ -	$ 26,602	$ 72,585
43	Total Commodity (Incl Hedging)	$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 3,539,292

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 3

Unitil
Northern Utilities, Inc.

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

Line	Sales Revenues		Winter						Summer						
		Oct-10	(Forecast) Nov-10	(Forecast) Dec-10	(Forecast) Jan-11	(Forecast) Feb-11	(Forecast) Mar-11	(Forecast) Apr-11	(Forecast) May-11	(Forecast) Jun-11	(Forecast) Jul-11	(Forecast) Aug-11	(Forecast) Sep-11	(Forecast) Oct-11	Total
1	Volumes														
2	Residential Heat & Non Heat								786,450	453,723	435,582	384,597	467,364	746,974	3,274,690
3	Sales HLF Classes								322,617	283,547	244,765	312,352	308,414	362,399	1,834,095
4	Sales LLF Classes								536,118	309,409	145,375	251,488	361,106	688,360	2,291,857
5	Total								1,645,185	1,046,679	825,723	948,437	1,136,884	1,797,734	7,400,642
6	Rates														
7	Residential Heat & Non Heat CGA								$0.6545	$0.6545	$0.6545	$0.6545	$0.6545	$0.6545	
8	Sales HLF Classes CGA								$0.6075	$0.6075	$0.6075	$0.6075	$0.6075	$0.6075	
9	Sales LLF Classes CGA								$0.6905	$0.6905	$0.6905	$0.6905	$0.6905	$0.6905	
10	Revenues														
11	Residential Heat & Non Heat								$ (708,959)	$ (445,259)	$ (259,549)	$ (249,311)	$ (252,993)	$ (333,495)	$ (2,249,565)
12	Sales HLF Classes								$ (86,410)	$ (220,075)	$ (197,759)	$ (206,350)	$ (191,072)	$ (200,117)	$ (1,101,783)
13	Sales LLF Classes								$ (284,389)	$ (350,942)	$ (178,495)	$ (164,142)	$ (195,933)	$ (308,480)	$ (1,482,380)
14	Total Sales								$ (1,079,758)	$ (1,016,275)	$ (635,803)	$ (619,802)	$ (639,998)	$ (842,092)	$ (4,833,728)
15															

Line	Gas Costs and Credits		Winter						Summer						
16															
17			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18		Oct-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
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 82,882	$ 82,882	$ 82,882	$ 82,882	$ 82,882	$ 82,882	$ 497,292
21	Storage								$ 97,242	$ 97,242	$ 97,242	$ 97,242	$ 97,242	$ 97,242	$ 583,451
22	Peaking								$ 19,621	$ 19,621	$ 19,621	$ 19,621	$ 19,621	$ 19,621	$ 117,728
24	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 199,745	$ 199,745	$ 199,745	$ 199,745	$ 199,745	$ 199,745	$ 1,198,470
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								304,244	188,838	139,235	176,289	216,266	349,849	1,374,721
27	Pipeline Costs Modeled in Sendout™								$ 1,549,919	$ 961,254	$ 715,227	$ 911,185	$ 1,119,926	$ 1,837,342	$ 7,094,853
28	NYMEX Price Used for Forecast								$ 4.7070	$ 4.7390	$ 4.7910	$ 4.8160	$ 4.8210	$ 4.8690	
29	NYMEX Price Used for Update								$ 4.1080	$ 4.1760	$ 4.2600	$ 4.3090	$ 4.3240	$ 4.3730	
30	Increase/(Decrease) NYMEX Price								$ (1)	$ (1)	$ (1)	$ (1)	$ (0)	$ (0)	
31	Increase/(Decrease) in Pipeline Costs								$ (182,242)	$ (106,316)	$ (73,934)	$ (89,379)	$ (107,484)	$ (173,525)	
32	Updated Pipeline Costs								$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 4.50	$ 4.53	$ 4.61	$ 4.66	$ 4.68	$ 4.76	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	
37	New Hampshire Allocated Percentage								54.38%	55.69%	59.38%	54.04%	52.90%	51.76%	
38	NH Updated Pipeline Costs								$ 743,740	$ 476,107	$ 380,786	$ 444,065	$ 535,555	$ 861,268	$ 3,441,521
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								14	0	0	0	0	9	
42	Average Purchase Price								$ 4.7120	$ -	$ -	$ -	$ -	$ 4.9440	
43	NYMEX Price Used for Forecast								$ 4.7070	$ 4.7390	$ 4.7910	$ 4.8160	$ 4.8210	$ 4.8690	
44	NYMEX Price Used for Update								$ 4.1080	$ 4.1760	$ 4.2600	$ 4.3090	$ 4.3240	$ 4.3730	
45	Increase/(Decrease) NYMEX Price								(0.5990)	(0.5630)	(0.5310)	(0.5070)	(0.4970)	(0.4960)	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ 84,560	$ -	$ -	$ -	$ -	$ 51,390	$ 135,950
47	New Hampshire Allocated Percentage								54.38%	55.69%	59.38%	54.04%	52.90%	51.76%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 45,984	$ -	$ -	$ -	$ -	$ 26,602	$ 72,585
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								$ 4.7070	$ 4.7390	$ 4.7910	$ 4.8160	$ 4.8210	$ 4.8690	
53	NYMEX Price Used for Update								$ 4.1080	$ 4.1760	$ 4.2600	$ 4.3090	$ 4.3240	$ 4.3730	
54	Increase/(Decrease) NYMEX Price								(0.5990)	(0.5630)	(0.5310)	(0.5070)	(0.4970)	(0.4960)	
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								$ 743,740	$ 476,107	$ 380,786	$ 444,065	$ 535,555	$ 861,268	$ 3,441,521
60	Hedging (Gain)/Loss Estimate								$ 45,984	$ -	$ -	$ -	$ -	$ 26,602	$ 72,585
61	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Peaking								$ 3,872	$ 3,993	$ 4,561	$ 4,282	$ 4,164	$ 4,314	$ 25,185
63	Total Commodity Costs								$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 3,539,292

Northern Utilities

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

#		Oct-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
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**		$ -	$ -	$ -	$ -	$ -	$ -	$ 993,341	$ 679,845	$ 585,092	$ 648,093	$ 739,464	$ 1,091,928	$ 4,737,762
75			Winter						Summer						
76			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Oct-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
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 993,341	$ 679,845	$ 585,092	$ 648,093	$ 739,464	$ 1,091,928	$ 4,737,762
80	Working Capital Percentage		0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	
81	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -	$ -	$ 560	$ 383	$ 330	$ 365	$ 417	$ 615	$ 2,670
82	Beginning Period Working Capital Balance		$ (7,494)	$ (7,508)	$ (7,522)	$ (7,536)	$ (7,550)	$ (7,565)	$ (7,579)	$ (7,033)	$ (6,662)	$ (6,345)	$ (5,991)	$ (5,585)	
83	End of Period Working Capital Allowance		$ (7,494)	$ (7,508)	$ (7,522)	$ (7,536)	$ (7,550)	$ (7,565)	$ (7,019)	$ (6,650)	$ (6,333)	$ (5,980)	$ (5,574)	$ (4,970)	
84	Interest		$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (13)	$ (12)	$ (12)	$ (11)	$ (10)	$ (156)
85	End of period with Interest	$ (7,494)	$ (7,508)	$ (7,522)	$ (7,536)	$ (7,550)	$ (7,565)	$ (7,579)	$ (7,033)	$ (6,662)	$ (6,345)	$ (5,991)	$ (5,585)	$ (4,980)	
86	Bad Debt														
87	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 993,341	$ 679,845	$ 585,092	$ 648,093	$ 739,464	$ 1,091,928	$ 4,737,762
88	Prior Period Over/Under Collection	$ 124,276	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124,276
89	Working Capital Allowance		$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ (65)	$ (241)	$ (295)	$ (259)	$ (208)	$ (9)	$ (4,824)
90	Subtotal	$ 124,276	$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ (625)	$ 993,276	$ 679,604	$ 584,797	$ 647,833	$ 739,256	$ 1,091,919	$ 4,857,215
91	Bad Debt Percentage	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
92	Bad Debt Allowance	$ 559	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ 4,470	$ 3,058	$ 2,632	$ 2,915	$ 3,327	$ 4,914	$ 21,857
93	Beginning Period Bad Debt Balance		$ 3,159	$ 3,162	$ 3,165	$ 3,168	$ 3,172	$ 3,175	$ 3,178	$ 7,658	$ 10,733	$ 13,387	$ 16,331	$ 19,691	
94	End of Period Bad Debt Balance		$ 3,156	$ 3,159	$ 3,162	$ 3,166	$ 3,169	$ 3,172	$ 7,648	$ 10,716	$ 13,365	$ 16,303	$ 19,657	$ 24,605	
95	Interest		$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 10	$ 17	$ 23	$ 28	$ 34	$ 42	$ 189
96	End of Period Bad Debt Balance with Interest	$ 3,159	$ 3,162	$ 3,165	$ 3,168	$ 3,172	$ 3,175	$ 3,178	$ 7,658	$ 10,733	$ 13,387	$ 16,331	$ 19,691	$ 24,646	
97	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	NHPUC Consultant Costs		$ 15,874	$ 7,611	$ 5,505										$ 28,990
99	Miscellaneous Overhead								$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 25,964
100	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
101	Beginning Balance Over/Under Collection		$ 124,276	$ 140,398	$ 148,280	$ 154,069	$ 154,358	$ 154,648	$ 154,939	$ 69,498	$ (33,255)	$ (8,260)	$ 28,996	$ 61,241	$ 1,149,188
102	Net Costs - Revenues		$ 15,874	$ 7,611	$ 5,505	$ -	$ -	$ -	$ (85,652)	$ (102,787)	$ 25,034	$ 37,237	$ 32,160	$ 8,856	$ (56,162)
103	Ending Balance before Interest		$ 140,150	$ 148,009	$ 153,785	$ 154,069	$ 154,358	$ 154,648	$ 69,287	$ (33,290)	$ (8,221)	$ 28,977	$ 61,157	$ 70,097	$ 1,093,026
104	Average Balance		$ 132,213	$ 144,204	$ 151,033	$ 154,069	$ 154,358	$ 154,648	$ 112,113	$ 18,104	$ (20,738)	$ 10,358	$ 45,076	$ 65,669	$ 1,121,107
105	Interest Rate		2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	
106	Interest Expense		$ 248	$ 271	$ 284	$ 290	$ 290	$ 291	$ 211	$ 34	$ (39)	$ 19	$ 85	$ 123	$ 2,107
108	Ending Balance Incl Interest Expense	$ 124,276	$ 140,398	$ 148,280	$ 154,069	$ 154,358	$ 154,648	$ 154,939	$ 69,498	$ (33,255)	$ (8,260)	$ 28,996	$ 61,241	$ 70,221	
109	**Total Over/Under Collection Ending Balance**	$ 119,941	$ 136,052	$ 143,923	$ 149,701	$ 149,979	$ 150,258	$ 150,538	$ 70,105	$ (28,040)	$ 291	$ 40,871	$ 76,522	$ 89,821	
110															
111	**Total Indirect Cost of Gas**	$ 120,500	$ 16,111	$ 7,871	$ 5,778	$ 278	$ 279	$ 280	$ 9,546	$ 8,970	$ 7,624	$ 7,670	$ 7,818	$ 8,770	$ 201,495
112															
113	**Total Cost of Gas**	$ 120,500	$ 16,111	$ 7,871	$ 5,778	$ 278	$ 279	$ 280	$ 999,324	$ 918,131	$ 664,134	$ 660,382	$ 675,649	$ 855,391	$ 4,924,108
114															
115	**Total Interest**	$ -	$ 240	$ 263	$ 276	$ 281	$ 282	$ 282	$ 207	$ 39	$ (26)	$ 39	$ 110	$ 156	$ 2,150

ıarges to NU-NH
mar in GSGT Rate Case

Line	Invoice No.	Date	Paid Date	Amount	
1	11365	9/28/2010	11/1/2010	$6,575.00	
2	11372	10/27/2010	11/1/2010	$11,902.16	
3	11385	11/23/2010	12/13/2010	$8,859.25	
4	11391	1/4/2011	1/6/2011	$6,407.90	
5				$33,744.31	
6	**To Capacity Assignment:**				
7	Recovery Rate ($ per Dth)			$ 1.17	
8	NUI-NH Pipeline & Storage MDQ Assigned (Dth)			4,069	
9	NHPUC Consultant Costs Allocated to Capacity Assignment			$4,754.68	14.09%
10	NHPUC Consultant Costs Allocated to Retail Customers			$28,989.63	85.91%
11	**To Retail Customers:**				
12			Month	Amount	
13			November	$15,873.67	
14			December	$7,610.95	
15			January	$5,505.01	
16	NHPUC Consultant Costs Allocated to Retail Customers			$28,989.63	85.91%

Schedule 5A

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2010 through October 31, 2011

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ	Dth / GJ	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Currency	Months Per Year	Support for Demand Rate	Note	Monthly Demand	Annual Demand
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	286	Dth	Centerville, NJ	Taunton, MA	$ 5.9771	USD	12	FXW-5A, Page 1		$ 1,709	$ 20,513
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	965	Dth	Lambertville, NJ	Taunton, MA	$ 5.9771	USD	12	FXW-5A, Page 1		$ 5,768	$ 69,215
Algonquin	93002F	AFT-1 (AFT-2)	No	4,211	Dth	Mendon, MA	Brockton, MA	$ 6.1138	USD	12	FXW-5A, Page 2		$ 25,745	$ 308,943
Granite	10-010-FT-NN	FT-NN	No	100,000	Dth	NA	NA	$ 1.6666	USD	2	FXW-5A, Page 3	1	$ 166,660	$ 333,320
Granite	10-010-FT-NN	FT-NN	No	100,000	Dth	NA	NA	$ 2.8000	USD	10	FXW-5A, Page 4	1	$ 280,000	$ 2,800,000
Iroquois	R181001	RTS-1	No	6,569	Dth	Zone 1	Zone 1	$ 6.5971	USD	12	FXW-5A, Page 5		$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Dth	Pittsburgh	GSGT	$ 27.4017	USD	1	FXW-5A, Page 6	2	$ 30,142	$ 30,142
PNGTS	1997-003	FT	No	1,100	Dth	Pittsburgh	GSGT	$ 40.2456	USD	11	FXW-5A, Page 7	2	$ 44,270	$ 486,972
PNGTS	1997-004	FT	Yes	33,000	Dth	Pittsburgh	GSGT	$ 52.0632	USD	1	FXW-5A, Page 6	3	$ 1,718,086	$ 1,718,086
PNGTS	1997-004	FT	Yes	33,000	Dth	Pittsburgh	GSGT	$ 76.4666	USD	4	FXW-5A, Page 7	3	$ 2,523,398	$ 10,093,591
Tennessee	5083	FT-A	No	4,605	Dth	Zone 0	Zone 6	$ 16.5900	USD	7	FXW-5A, Page 8		$ 76,397	$ 534,779
Tennessee	5083	FT-A	No	8,550	Dth	Zone L	Zone 6	$ 15.1500	USD	7	FXW-5A, Page 8	4	$ 129,533	$ 906,728
Tennessee	5265	FT-A	No	2,653	Dth	Zone 4	Zone 6	$ 5.8900	USD	7	FXW-5A, Page 8		$ 15,626	$ 109,383
Tennessee	5292	FT-A	No	1,406	Dth	Zone 5	Zone 6	$ 4.9300	USD	7	FXW-5A, Page 8		$ 6,932	$ 48,521
Tennessee	39735	FT-A	No	929	Dth	Zone 5	Zone 6	$ 4.9300	USD	7	FXW-5A, Page 8		$ 4,580	$ 32,060
Tennessee	41099	FT-A	No	4,267	Dth	Zone 5	Zone 6	$ 4.9300	USD	7	FXW-5A, Page 8		$ 21,036	$ 147,254
Tennessee	46314	FT-A	No	950	Dth	Zone 5	Zone 6	$ 4.9300	USD	7	FXW-5A, Page 8		$ 4,684	$ 32,785
Tennessee	31861	NET-284	No	1,382	Dth	3	3	$ 5.0700	USD	7	FXW-5A, Page 9	5	$ 7,007	$ 49,047
Tennessee	31861	NET-284	No	844	Dth	3	4	$ 10.6100	USD	7	FXW-5A, Page 9	5	$ 8,955	$ 62,684
Tennessee	5083	FT-A	No	4,605	Dth	Zone 0	Zone 6	$ 34.2310	USD	5	FXW-5A, Page 8		$ 157,634	$ 788,169
Tennessee	5083	FT-A	No	8,550	Dth	Zone L	Zone 6	$ 30.4605	USD	5	FXW-5A, Page 8	4	$ 260,437	$ 1,302,186
Tennessee	5265	FT-A	No	2,653	Dth	Zone 4	Zone 6	$ 12.4456	USD	5	FXW-5A, Page 8		$ 33,018	$ 165,091
Tennessee	5292	FT-A	No	1,406	Dth	Zone 5	Zone 6	$ 11.0128	USD	5	FXW-5A, Page 8		$ 15,484	$ 77,420
Tennessee	39735	FT-A	No	929	Dth	Zone 5	Zone 6	$ 11.0128	USD	5	FXW-5A, Page 8		$ 10,231	$ 51,154
Tennessee	41099	FT-A	No	4,267	Dth	Zone 5	Zone 6	$ 11.0128	USD	5	FXW-5A, Page 8		$ 46,992	$ 234,958
Tennessee	46314	FT-A	No	950	Dth	Zone 5	Zone 6	$ 11.0128	USD	5	FXW-5A, Page 8		$ 10,462	$ 52,311
Tennessee	31861	NET-284	No	1,382	Dth	3	3	$ 11.0128	USD	5	FXW-5A, Page 9	5	$ 15,220	$ 76,098
Tennessee	31861	NET-284	No	844	Dth	3	4	$ 11.0128	USD	5	FXW-5A, Page 9	5	$ 9,295	$ 46,474
Texas Eastern	800384	FT-1	No	965	Dth	M3	M3	$ 5.8080	USD	12	FXW-5A, Page 10 & 20	6	$ 5,605	$ 67,257
Texas Eastern	800436	CDS	No	64	Dth	M3	M3	$ 5.3710	USD	12	FXW-5A, Page 10		$ 344	$ 4,125
Texas Eastern	800464	CDS	No	33	Dth	ELA	M1	$ 2.3750	USD	12	FXW-5A, Page 10	7	$ 78	$ 941
Texas Eastern	800464	CDS	No	9	Dth	ETX	M1	$ 2.1890	USD	12	FXW-5A, Page 10	7	$ 20	$ 236
Texas Eastern	800464	CDS	No	16	Dth	STX	M1	$ 6.8120	USD	12	FXW-5A, Page 10	7	$ 109	$ 1,308
Texas Eastern	800464	CDS	No	18	Dth	WLA	M1	$ 2.8280	USD	12	FXW-5A, Page 10	7	$ 51	$ 611
Texas Eastern	800464	CDS	No	59	Dth	M1	M3	$ 11.2800	USD	12	FXW-5A, Page 10	7	$ 666	$ 7,986
Union	M12205	M12	No	6,333	GJ	Dawn	Parkway	$ 2.3666	CAD	12			$ 15,440	$ 185,284
TransCanada	29594	FT	No	6,264	GJ	Parkway	Iroquois	$ 8.2306	CAD	4	FXW-5A, Page 11 & 12	8	$ 53,114	$ 212,455
TransCanada	33322	FT	No	35,872	GJ	Dawn	E. Hereford	$ 18.7330	CAD	4	FXW-5A, Page 11 & 12	9	$ 692,285	$ 2,769,140
TransCanada	29594	FT	No	6,264	GJ	Parkway	Iroquois	$ 11.2056	CAD	8	FXW-5A, Page 11 & 12	8	$ 72,312	$ 578,495
TransCanada	33322	FT	No	35,872	GJ	Dawn	E. Hereford	$ 27.2444	CAD	8	FXW-5A, Page 11 & 12	9	$ 1,006,825	$ 8,054,598
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Dth	Alliance	Dawn	$ 7.6042	USD	12	FXW-5A, Page 13		$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	Dth	W-10	Dawn	$ 4.5625	USD	5	FXW-5A, Page 14		$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Dth	Alliance	St. Clair	$ 7.7745	USD	12	FXW-5A, Page 15 & 16	10	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,404	GJ	St. Clair	Dawn	$ 0.4623	CAD	12	FXW-5A, Page 17		$ 3,050	$ 36,600

Total Annual Demand Costs $ 35,539,975

Exchange Rate (CAD/USD) = 1.0302

FXW-5A, Page 18

Note 1: Granite filed new rates under FERC docket RP10-896. New Granite rates projected to take effect on 1/1/2011.
Note 2: PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.
Note 3: Seasonal Recourse Rate. PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.
Note 4: The demand rate applied for Zone L to Zone 6 transportation capacity Zone 1 to Zone 6 demand rate.
Note 5: The rate is the Segment 3 demand rate of $5.07 per Dth plus the Segment 4 demand rate of $5.54 per Dth.
Note 6: For Contract ID 800384, Northern pays both the FT-1 Reservation Charge of $5.148 (Page 10 of FXW-5A) and the FT-1/FTS Other Transportation Services charge of $0.66 (Page 20 of FXW-5A).
Note 7: Rate is expressed in the tariff sheet as as a Delivery Zone of AAB ("Access Area Boundary"). The AAB is the border between the Access Areas (ETX, ELA, WLA, and STX) and the M1 Zone.
Note 8: Rate is the Delivery Pressure Toll for deliveries into Iroquois of $CAD 0.78572 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to Iroquois of $CAD 10.82669 (Page 12 of FXW-5A).
Note 9: Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.96558 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to E. Hereford of $CAD 16.76744 (Page 12 of FXW-5A).
Note 10: Maximum tariff rate of $7.7745 (Page 15 of FXW-5A) exceeds negotiated rate of $8.0908 (Page 16 of FXW-5A). Therefore, Maximum tariff rate applies.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2010 through October 31, 2011

Pipeline	Contract ID	MDQ	Dth / GJ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Monthly Demand	Monthly Pipeline Allocated Cost	Monthly Storage Allocated Cost	Monthly Peaking Allocated Cost	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93201A1C	286	Dth	201	85		70%	30%	0%	$ 1,709	$ 1,201	$ 508	$ -	$ 20,513	$ 14,417	$ 6,097	$ -
Algonquin	93201A1C	965	Dth	965			100%	0%	0%	$ 5,768	$ 5,768	$ -	$ -	$ 69,215	$ 69,215	$ -	$ -
Algonquin	93002F	4,211	Dth	4,211			100%	0%	0%	$ 25,745	$ 25,745	$ -	$ -	$ 308,943	$ 308,943	$ -	$ -
Granite	10-010-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 166,660	$ 39,825	$ 59,123	$ 67,712	$ 333,320	$ 79,650	$ 118,245	$ 135,425
Granite	10-010-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 280,000	$ 66,909	$ 99,330	$ 113,761	$ 2,800,000	$ 669,088	$ 993,300	$ 1,137,612
Iroquois	R181001	6,569	Dth	6,569			100%	0%	0%	$ 43,336	$ 43,336	$ -	$ -	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 30,142	$ 30,142	$ -	$ -	$ 30,142	$ 30,142	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 44,270	$ 44,270	$ -	$ -	$ 486,972	$ 486,972	$ -	$ -
PNGTS	1997-004	33,000	Dth		33,000		0%	100%	0%	$ 1,718,086	$ -	$ 1,718,086	$ -	$ 1,718,086	$ -	$ 1,718,086	$ -
PNGTS	1997-004	33,000	Dth		33,000		0%	100%	0%	$ 2,523,398	$ -	$ 2,523,398	$ -	$ 10,093,591	$ -	$ 10,093,591	$ -
Tennessee	5083	4,605	Dth	4,605			100%	0%	0%	$ 76,397	$ 76,397	$ -	$ -	$ 534,779	$ 534,779	$ -	$ -
Tennessee	5083	8,550	Dth	8,550			100%	0%	0%	$ 129,533	$ 129,533	$ -	$ -	$ 906,728	$ 906,728	$ -	$ -
Tennessee	5265	2,653	Dth		2,653		0%	100%	0%	$ 15,626	$ -	$ 15,626	$ -	$ 109,383	$ -	$ 109,383	$ -
Tennessee	5292	1,406	Dth	1,406	-		100%	0%	0%	$ 6,932	$ 6,932	$ -	$ -	$ 48,521	$ 48,521	$ -	$ -
Tennessee	39735	929	Dth	929	-		100%	0%	0%	$ 4,580	$ 4,580	$ -	$ -	$ 32,060	$ 32,060	$ -	$ -
Tennessee	41099	4,267	Dth	4,267	-		100%	0%	0%	$ 21,036	$ 21,036	$ -	$ -	$ 147,254	$ 147,254	$ -	$ -
Tennessee	46314	950	Dth	950	-		100%	0%	0%	$ 4,684	$ 4,684	$ -	$ -	$ 32,785	$ 32,785	$ -	$ -
Tennessee	31861	1,382	Dth	1,382			100%	0%	0%	$ 7,007	$ 7,007	$ -	$ -	$ 49,047	$ 49,047	$ -	$ -
Tennessee	31861	844	Dth	844			100%	0%	0%	$ 8,955	$ 8,955	$ -	$ -	$ 62,684	$ 62,684	$ -	$ -
Tennessee	5083	4,605	Dth	4,605			100%	0%	0%	$ 157,634	$ 157,634	$ -	$ -	$ 788,169	$ 788,169	$ -	$ -
Tennessee	5083	8,550	Dth	8,550			100%	0%	0%	$ 260,437	$ 260,437	$ -	$ -	$ 1,302,186	$ 1,302,186	$ -	$ -
Tennessee	5265	2,653	Dth		2,653		0%	100%	0%	$ 33,018	$ -	$ 33,018	$ -	$ 165,091	$ -	$ 165,091	$ -
Tennessee	5292	1,406	Dth	1,406	-		100%	0%	0%	$ 15,484	$ 15,484	$ -	$ -	$ 77,420	$ 77,420	$ -	$ -
Tennessee	39735	929	Dth	929	-		100%	0%	0%	$ 10,231	$ 10,231	$ -	$ -	$ 51,154	$ 51,154	$ -	$ -
Tennessee	41099	4,267	Dth	4,267	-		100%	0%	0%	$ 46,992	$ 46,992	$ -	$ -	$ 234,958	$ 234,958	$ -	$ -
Tennessee	46314	950	Dth	950	-		100%	0%	0%	$ 10,462	$ 10,462	$ -	$ -	$ 52,311	$ 52,311	$ -	$ -
Tennessee	31861	1,382	Dth	1,382			100%	0%	0%	$ 15,220	$ 15,220	$ -	$ -	$ 76,098	$ 76,098	$ -	$ -
Tennessee	31861	844	Dth	844			100%	0%	0%	$ 9,295	$ 9,295	$ -	$ -	$ 46,474	$ 46,474	$ -	$ -
Texas Eastern	800384	965	Dth	965	-		100%	0%	0%	$ 5,605	$ 5,605	$ -	$ -	$ 67,257	$ 67,257	$ -	$ -
Texas Eastern	800436	64	Dth	64	-		100%	0%	0%	$ 344	$ 344	$ -	$ -	$ 4,125	$ 4,125	$ -	$ -
Texas Eastern	800464	33	Dth	33			100%	0%	0%	$ 78	$ 78	$ -	$ -	$ 941	$ 941	$ -	$ -
Texas Eastern	800464	9	Dth	9			100%	0%	0%	$ 20	$ 20	$ -	$ -	$ 236	$ 236	$ -	$ -
Texas Eastern	800464	16	Dth	16			100%	0%	0%	$ 109	$ 109	$ -	$ -	$ 1,308	$ 1,308	$ -	$ -
Texas Eastern	800464	18	Dth	18			100%	0%	0%	$ 51	$ 51	$ -	$ -	$ 611	$ 611	$ -	$ -
Texas Eastern	800464	59	Dth	59			100%	0%	0%	$ 666	$ 666	$ -	$ -	$ 7,986	$ 7,986	$ -	$ -
Union		6,333	GJ				100%	0%	0%	$ 15,440	$ 15,440	$ -	$ -	$ 185,284	$ 185,284	$ -	$ -
TransCanada	29594	6,264	GJ	6,264	-		100%	0%	0%	$ 53,114	$ 53,114	$ -	$ -	$ 212,455	$ 212,455	$ -	$ -
TransCanada	33322	35,872	GJ		35,872		0%	100%	0%	$ 692,285	$ -	$ 692,285	$ -	$ 2,769,140	$ -	$ 2,769,140	$ -
TransCanada	29594	6,264	GJ	6,264	-		100%	0%	0%	$ 72,312	$ 72,312	$ -	$ -	$ 578,495	$ 578,495	$ -	$ -
TransCanada	33322	35,872	GJ		35,872		0%	100%	0%	$ 1,006,825	$ -	$ 1,006,825	$ -	$ 8,054,598	$ -	$ 8,054,598	$ -
Vector	CRL-NUI-0725	17,172	Dth		17,172		0%	100%	0%	$ 130,579	$ -	$ 130,579	$ -	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086	Dth		17,086		0%	100%	0%	$ 77,955	$ -	$ 77,955	$ -	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	Dth	6,070	-		100%	0%	0%	$ 47,191	$ 47,191	$ -	$ -	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,404	GJ	6,404	-		100%	0%	0%	$ 3,050	$ 3,050	$ -	$ -	$ 36,600	$ 36,600	$ -	$ -
Annual Total Demand Costs										$ 7,778,258	$ 1,240,052	$ 6,356,732	$ 181,473	$ 35,539,975	$ 8,282,681	$ 25,984,258	$ 1,273,037

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2010 through October 31, 2011

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0185	$ 1.1500	7	FXW-5A, Page 19	$ 9,677	$ 33,584	$ 34,156	$ 67,740
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0262	$ 1.8900	5	FXW-5A, Page 19	$ 14,814	$ 33,973	$ 40,096	$ 74,069
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.6020	12	FXW-5A, Page 20	$ 133	$ 189	$ 1,412	$ 1,601
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	FXW-5A, Page 20	$ 99	$ 497	$ 687	$ 1,184
W-10	01052	Storage	Yes	3,400,000		34,000			12	FXW-5A, Page 21	$ 240,833	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges $ 3,034,595

MSQ = Maximum Space Quantity 13.1103545 8.01319821 42.6629413
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
Peaking Contract Demand Cost Estimates
November 1, 2010 through October 31, 2011

Resource	Contract Quantity	Maximum Daily Quantity	Contract Quantity Demand Rate	MDQ Demand Rate	Months Per Year	Support for Demand Rates	Annual CQ Demand Cost	Annual MDQ Demand Cost	Monthly Fixed Charges	Annual Fixed Charges
Peaking Supply 1	755,000	5,000	$ -	$ 44.09	12	FXW-5A, Page 22	$ -	$ 2,645,238	$ 220,437	$ 2,645,238
Peaking Supply 2	1,435,000	57,400	$ 1.3500	$ -	5	FXW-5A, Page 23	$ 1,937,250	$ -	$ 387,450	$ 1,937,250
Total Peaking Supply Contract Demand Costs										$ 4,582,488

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2010 through October 31, 2011

Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	$ (442,000)
Wash 10 via Vector, TCPL, PNGTS	$ (1,100,000)
PNGTS Contract 1997-003	$ (30,000)
Tennessee Niagara	$ (100,000)
Tennessee Long-Haul	$ (835,000)
Total Asset Management	$ (2,507,000)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (66,701)
AGT Contract 93201A1C	$ (98,779)
Tennessee 5265	$ (259,050)
Total Capacity Release	$ (424,530)

Total Asset Management and Capacity Release Revenue	$ (2,931,530)

Schedule 5B

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2010 through October 2011		
Item	**Revenue**	**Reference**
NH Division Pipeline Contract Capacity Assignment	$ (2,363,684)	Page 2
NH Division Storage Contract Capacity Assignment	$ (218,188)	Page 3
NH Division Peaking Demand	$ (501,740)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 71,945	Page 5
NH Division Net PNGTS Litigation Costs & Projected 2008 Rate Case Refund Assigned to Retail Suppliers	$ 31,856	Page 6
NH Division Capacity Assignment Demand Revenue	$ (2,979,810)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2010 through October 31, 2011

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	93201A1C	$ 14,417	$ 6,097	$ -	N	NA	NA	-	-	$ -
Algonquin	93201A1C	$ 69,215	$ -	$ -	N	NA	NA	-	-	$ -
Algonquin	93002F	$ 308,943	$ -	$ -	Y	4,211	-	(267)	-	$ (19,589)
Granite	10-010-FT-NN	$ 79,650	$ 118,245	$ 135,425	Y	23,896	35,475	(1,516)	(2,553)	$ (21,982)
Granite	10-010-FT-NN	$ 669,088	$ 993,300	$ 1,137,612	Y	23,896	35,475	(1,516)	(2,553)	$ (184,660)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	(417)	-	$ (33,012)
PNGTS	1997-003	$ 30,142	$ -	$ -	Y	1,100	-	(70)	-	$ (1,918)
PNGTS	1997-003	$ 486,972	$ -	$ -	Y	1,100	-	(70)	-	$ (30,989)
PNGTS	1997-004	$ -	$ 1,718,086	$ -	Y	-	33,000	-	(2,375)	$ (123,650)
PNGTS	1997-004	$ -	$ 10,093,591	$ -	Y	-	33,000	-	(2,375)	$ (726,433)
Tennessee	5083	$ 534,779	$ -	$ -	Y	4,605	-	(292)	-	$ (33,910)
Tennessee	5083	$ 906,728	$ -	$ -	Y	8,550	-	(542)	-	$ (57,479)
Tennessee	5265	$ -	$ 109,383	$ -	Y	-	2,653	-	(191)	$ (7,875)
Tennessee	5292	$ 48,521	$ -	$ -	Y	1,406	-	(89)	-	$ (3,071)
Tennessee	39735	$ 32,060	$ -	$ -	Y	929	-	(59)	-	$ (2,036)
Tennessee	41099	$ 147,254	$ -	$ -	Y	4,267	-	(271)	-	$ (9,352)
Tennessee	46314	$ 32,785	$ -	$ -	Y	950	-	(60)	-	$ (2,071)
Tennessee	31861	$ 49,047	$ -	$ -	Y	1,382	-	(88)	-	$ (3,123)
Tennessee	31861	$ 62,684	$ -	$ -	Y	844	-	(54)	-	$ (4,011)
Tennessee	5083	$ 788,169	$ -	$ -	Y	4,605	-	(292)	-	$ (49,977)
Tennessee	5083	$ 1,302,186	$ -	$ -	Y	8,550	-	(542)	-	$ (82,548)
Tennessee	5265	$ -	$ 165,091	$ -	Y	-	2,653	-	(191)	$ (11,886)
Tennessee	5292	$ 77,420	$ -	$ -	Y	1,406	-	(89)	-	$ (4,901)
Tennessee	39735	$ 51,154	$ -	$ -	Y	929	-	(59)	-	$ (3,249)
Tennessee	41099	$ 234,958	$ -	$ -	Y	4,267	-	(271)	-	$ (14,922)
Tennessee	46314	$ 52,311	$ -	$ -	Y	950	-	(60)	-	$ (3,304)
Tennessee	31861	$ 76,098	$ -	$ -	Y	1,382	-	(88)	-	$ (4,846)
Tennessee	31861	$ 46,474	$ -	$ -	Y	844	-	(54)	-	$ (2,973)
Texas Eastern	800384	$ 67,257	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800436	$ 4,125	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 941	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 236	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 1,308	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 611	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 7,986	$ -	$ -	N	NA	NA	-	-	$ -
Union	0	$ 185,284	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	29594	$ 212,455	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	33322	$ -	$ 2,769,140	$ -	Y	-	35,872	-	(2,582)	$ (199,318)
TransCanada	29594	$ 578,495	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	33322	$ -	$ 8,054,598	$ -	Y	-	35,872	-	(2,582)	$ (579,755)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	(1,236)	$ (112,785)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	(1,230)	$ (28,059)
Vector	FT-1-NUI-0122	$ 566,295	$ -	$ -	N	NA	NA	-	-	$ -
Vector	FT-1-NUI-C0122	$ 36,600	$ -	$ -	N	NA	NA	-	-	$ -

Total NH Capacity Assignment Credits $ (2,363,684)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 1, 2010 through October 31, 2011

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned NH	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 67,740	Y	N	7.20%	(18,663)	(305)	$ (4,875)
Tennessee	5195	$ 74,069	Y	N	7.20%	(18,663)	(305)	$ (5,330)
W-10	01052	$ 2,890,000	Y	Y	7.20%	(244,685)	(2,447)	$ (207,982)

Total NH Division Storage Capacity Assignment $ (218,188)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 2010 through April 2011

Month	Retail Supplier 1	Retail Supplier 2	Retail Supplier 3	Retail Supplier 4	Retail Supplier 5	Retail Supplier 6	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-10	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Dec-10	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Jan-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Feb-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Mar-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Apr-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)

Total Division Peaking Demand Revenue $ (501,740)

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2009 through October 2010

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	$ (442,000)	No	Pipeline	6.34%	$ -
Wash 10 via Vector, TCPL, PNGTS	$ (1,100,000)	Yes	Pipeline	6.34%	$ 69,786
PNGTS Contract 1997-003	$ (30,000)	Yes	Storage	7.20%	$ 2,159
Tennessee Niagara	$ (100,000)	No	Pipeline	6.34%	$ -
Tennessee Long-Haul	$ (835,000)	No	Pipeline	6.34%	$ -
Total Asset Management	$ (2,507,000)				$ 71,945

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	6.34%	$ -
AGT Contract 93201A1C	$ (98,779)	No	Pipeline	6.34%	$ -
Tennessee 5265	$ (259,050)	No	Pipeline	7.20%	$ -
Total Capacity Release	$ (424,530)				$ -

Total Asset Management and Capacity Release Revenue	$ (2,931,530)				$ 71,945

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs & Projected 2008 Rate Case Refund - Assigned to Retail Suppliers
November 2010 through October 2011

PNGTS Litigation Costs	$	183,943
PNGTS Projected 2008 Rate Case Refund	$	(628,298)
Net PNGTS Litigation Items	$	(444,355)

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ (14,334)	Pipeline	6.34%	$ 909
PNGTS Contract 1997-004	33,000	97%	$ (430,021)	Storage	7.20%	$ 30,947
PNGTS Total	34,100	100%	$ (444,355)			$ 31,856

Schedule 8

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Summer 2011 vs. Summer 2010

			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								
	CGA 1	$1.0987	$119.76						$119.76								
	CGA 2	$1.0736		$161.04					$161.04								
	CGA 3	$1.1199			$209.42				$209.42								
	CGA 4	$1.1615				$218.36			$218.36								
	CGA 5	$1.1615					$192.81		$192.81								
	CGA 6	$1.1615						$153.32	$153.32								
	LDAC	$0.0454	$4.95	$6.81	$8.49	$8.54	$7.54	$5.99	$42.31								
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	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.6673								$60.06						$60.06	
	CGA 2	$0.6673									$36.70					$36.70	
	CGA 3	$0.6673										$20.02				$20.02	
	CGA 4	$0.6673											$20.02			$20.02	
	CGA 5	$0.6673												$28.03		$28.03	
	CGA 6	$0.6673													$47.38	$47.38	
	LDAC	$ 0.0456								$4.10	$2.51	$1.37	$1.37	$1.92	$3.24	$14.50	
		TOTAL	$172.36	$227.76	$288.88	$298.17	$265.04	$213.84	$1,466.05	$106.13	$70.71	$43.19	$43.19	$56.67	$86.90	$406.81	$1,872.86

			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 2009 - 2010																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$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								
	CGA 1	$1.0980	$119.68						$119.68								
	CGA 2	$1.0980		$164.70					$164.70								
	CGA 3	$1.0218			$191.08				$191.08								
	CGA 4	$1.0758				$202.25			$202.25								
	CGA 5	$1.0758					$178.58		$178.58								
	CGA 6	$0.6693						$88.35	$88.35								
	LDAC	$ 0.0297	$3.24	$4.46	$5.55	$5.58	$4.93	$3.92	$27.68								
Summer 2010																	
Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.6545								$58.91						$58.91	
	CGA 2	$0.5969									$32.83					$32.83	
	CGA 3	$0.7280										$21.84				$21.84	
	CGA 4	$0.7280											$21.84			$21.84	
	CGA 5	$0.7280												$30.58		$30.58	
	CGA 6	$0.7280													$51.69	$51.69	
	LDAC	$ 0.0297								$2.67	$1.63	$0.89	$0.89	$1.25	$2.11	$9.44	
		TOTAL	$170.57	$229.07	$267.60	$279.11	$248.21	$146.80	$1,341.35	$103.55	$65.97	$44.54	$44.54	$58.55	$90.09	$407.23	$1,748.58
		Change	$1.79	($1.31)	$21.28	$19.06	$16.83	$67.04	$124.70	$2.58	$4.75	($1.34)	($1.34)	($1.88)	($3.18)	**($0.42)**	$124.28
		% Chg	1.05%	-0.57%	7.95%	6.83%	6.78%	45.67%	9.30%	2.49%	7.20%	-3.02%	-3.02%	-3.21%	-3.53%	**-0.10%**	7.11%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2011 vs. Summer 2010

		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								
CGA 1	$1.1231	$216.76						$216.76								
CGA 2	$1.0980		$295.36					$295.36								
CGA 3	$1.1443			$341.00				$341.00								
CGA 4	$1.1859				$310.71			$310.71								
CGA 5	$1.1859					$277.50		$277.50								
CGA 6	$1.1859						$202.79	$202.79								
LDAC	$0.0259	$5.00	$6.97	$7.72	$6.79	$6.06	$4.43	$36.96								
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	$22.15	$23.08	$23.08	$136.62	
Over 75 units @	$0.2007								$8.43	$1.20	$0.00	$0.00	$2.81	$13.45	$25.89	
CGA 1	$0.7234								$84.64						$84.64	
CGA 2	$0.7234									$58.60					$58.60	
CGA 3	$0.7234										$52.08				$52.08	
CGA 4	$0.7234											$52.08			$52.08	
CGA 5	$0.7234												$64.38		$64.38	
CGA 6	$0.7234													$102.72	$102.72	
LDAC	$ 0.0166								$1.94	$1.34	$1.20	$1.20	$1.48	$2.36	$9.51	
TOTAL		$287.22	$383.04	$435.25	$396.80	$357.25	$268.26	$2,127.83	$136.79	$102.92	$94.13	$94.13	$110.45	$160.30	$698.73	$2,826.55

		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 2009 - 2010																
Customer Charge units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First 75 units @	$0.3077	$23.08	$23.08	$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								
CGA 1	$1.1058	$213.42						$213.42								
CGA 2	$1.1058		$297.46					$297.46								
CGA 3	$1.0296			$306.82				$306.82								
CGA 4	$1.0836				$283.90			$283.90								
CGA 5	$1.0836					$253.56		$253.56								
CGA 6	$0.6771						$115.78	$115.78								
LDAC	$ 0.0166	$3.20	$4.47	$4.95	$4.35	$3.88	$2.84	$23.69								
Summer 2010																
Customer Charge units @	$ 18.70								$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20	
First 75 units @	$0.3077								$23.08	$23.08	$22.15	$22.15	$23.08	$23.08	$136.62	
Over 75 units @	$0.2007								$8.43	$1.20	$0.00	$0.00	$2.81	$13.45	$25.89	
CGA 1	$0.6905								$80.79						$80.79	
CGA 2	$0.6329									$51.26					$51.26	
CGA 3	$0.7640										$55.01				$55.01	
CGA 4	$0.7640											$55.01			$55.01	
CGA 5	$0.7640												$68.00		$68.00	
CGA 6	$0.7640													$108.49	$108.49	
LDAC	$ 0.0211								$2.47	$1.71	$1.52	$1.52	$1.88	$3.00	$12.09	
TOTAL		$282.08	$382.64	$398.30	$367.56	$331.14	$179.67	$1,941.39	$133.46	$95.96	$97.38	$97.38	$114.46	$166.71	$705.35	$2,646.74
Change		$5.13	$0.40	$36.95	$29.24	$26.11	$88.60	$186.44	$3.32	$6.97	($3.25)	($3.25)	($4.01)	($6.40)	**($6.62)**	$179.81
% Chg		1.82%	0.11%	9.28%	7.95%	7.89%	49.31%	9.60%	2.49%	7.26%	-3.33%	-3.33%	-3.51%	-3.84%	**-0.94%**	6.79%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2011 vs. Summer 2010

			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								
	CGA 1	$1.1231	$1,744.17						$1,744.17								
	CGA 2	$1.0980		$2,830.64					$2,830.64								
	CGA 3	$1.1443			$3,736.14				$3,736.14								
	CGA 4	$1.1859				$4,865.75			$4,865.75								
	CGA 5	$1.1859					$4,034.43		$4,034.43								
	CGA 6	$1.1859						$2,932.73	$2,932.73								
	LDAC	$0.0259	$40.22	$66.77	$84.56	$106.27	$88.11	$64.05	$449.99								
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	$23.94	$40.91	$78.57	$410.15	
	CGA 1	$0.7234								$910.04						$910.04	
	CGA 2	$0.7234									$507.10					$507.10	
	CGA 3	$0.7234										$299.49				$299.49	
	CGA 4	$0.7234											$154.08			$154.08	
	CGA 5	$0.7234												$263.32		$263.32	
	CGA 6	$0.7234													$505.66	$505.66	
	LDAC	$ 0.0166								$20.88	$11.64	$6.87	$3.54	$6.04	$11.60	$60.57	
		TOTAL	$2,146.29	$3,458.36	$4,515.07	$5,829.12	$4,843.51	$3,537.34	$24,329.69	$1,132.62	$657.83	$413.19	$241.86	$370.57	$656.13	$3,472.21	$27,801.89

			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 2009 - 2010																	
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								
	CGA 1	$1.1058	$1,717.31						$1,717.31								
	CGA 2	$1.1058		$2,850.75					$2,850.75								
	CGA 3	$1.0296			$3,361.64				$3,361.64								
	CGA 4	$1.0836				$4,446.01			$4,446.01								
	CGA 5	$1.0836					$3,686.41		$3,686.41								
	CGA 6	$0.6771						$1,674.47	$1,674.47								
	LDAC	$ 0.0166	$25.78	$42.79	$54.20	$68.11	$56.47	$41.05	$288.41								
Summer 2010																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
All	units @	$0.1124								$141.40	$78.79	$46.53	$23.94	$40.91	$78.57	$410.15	
	CGA 1	$0.6905								$868.65						$868.65	
	CGA 2	$0.6329									$443.66					$443.66	
	CGA 3	$0.7640										$316.30				$316.30	
	CGA 4	$0.7640											$162.73			$162.73	
	CGA 5	$0.7640												$278.10		$278.10	
	CGA 6	$0.7640													$534.04	$534.04	
	LDAC	$ 0.0211								$26.54	$14.79	$8.74	$4.49	$7.68	$14.75	$76.99	
		TOTAL	$2,104.98	$3,454.49	$4,110.21	$5,371.22	$4,463.85	$2,256.08	$21,760.83	$1,096.89	$597.55	$431.87	$251.47	$386.99	$687.65	$3,452.41	$25,213.24
		Change	$41.31	$3.87	$404.86	$457.89	$379.66	$1,281.26	$2,568.86	$35.73	$60.29	($18.67)	($9.61)	($16.42)	($31.52)	$19.79	$2,588.65
		% Chg	1.96%	0.11%	9.85%	8.52%	8.51%	56.79%	11.80%	3.26%	10.09%	-4.32%	-3.82%	-4.24%	-4.58%	0.57%	10.27%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2011 vs. Summer 2010

			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								
	CGA 1	$0.9702	$1,670.68						$1,670.68								
	CGA 2	$0.9451		$1,971.48					$1,971.48								
	CGA 3	$0.9914			$2,309.96				$2,309.96								
	CGA 4	$1.0330				$2,409.99			$2,409.99								
	CGA 5	$1.0330					$2,366.60		$2,366.60								
	CGA 6	$1.0330						$1,933.78	$1,933.78								
	LDAC	$0.0259	$44.60	$54.03	$60.35	$60.42	$59.34	$48.48	$327.22								
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	$111.20	$111.20	$111.20	$667.20	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27	$14.82	$16.38	$25.27	$144.69	
	CGA 1	$0.5975								$902.23						$902.23	
	CGA 2	$0.5975									$820.97					$820.97	
	CGA 3	$0.5975										$745.08				$745.08	
	CGA 4	$0.5975											$711.03			$711.03	
	CGA 5	$0.5975												$722.98		$722.98	
	CGA 6	$0.5975													$791.09	$791.09	
	LDAC	$ 0.0166								$25.07	$22.81	$20.70	$19.75	$20.09	$21.98	$130.39	
	TOTAL		$2,079.55	$2,443.17	$2,823.77	$2,924.31	$2,873.68	$2,368.53	$15,513.02	$1,138.57	$1,044.45	$956.55	$917.10	$930.94	$1,009.84	$5,997.45	$21,510.47

			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 2009 - 2010																	
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								
	CGA 1	$1.0630	$1,830.49						$1,830.49								
	CGA 2	$1.0630		$2,217.42					$2,217.42								
	CGA 3	$0.9868			$2,299.24				$2,299.24								
	CGA 4	$1.0408				$2,428.19			$2,428.19								
	CGA 5	$1.0408					$2,384.47		$2,384.47								
	CGA 6	$0.6343						$1,187.41	$1,187.41								
	LDAC	$ 0.0211	$36.33	$44.01	$49.16	$49.23	$48.34	$39.50	$266.58								
Summer 2010																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
First	1,000 units @	$0.1112								$111.20	$111.20	$111.20	$111.20	$111.20	$111.20	$667.20	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27	$14.82	$16.38	$25.27	$144.69	
	CGA 1	$0.6075								$917.33						$917.33	
	CGA 2	$0.5499									$755.56					$755.56	
	CGA 3	$0.6810										$849.21				$849.21	
	CGA 4	$0.6810											$810.39			$810.39	
	CGA 5	$0.6810												$824.01		$824.01	
	CGA 6	$0.6810													$901.64	$901.64	
	LDAC	$ 0.0211								$31.86	$28.99	$26.31	$25.11	$25.53	$27.94	$165.74	
	TOTAL		$2,231.09	$2,679.10	$2,801.87	$2,931.31	$2,880.55	$1,613.18	$15,137.10	$1,160.47	$985.23	$1,066.28	$1,021.82	$1,037.42	$1,126.35	$6,397.57	$21,534.67
	Change		($151.54)	($235.93)	$21.90	($7.00)	($6.87)	$755.35	$375.92	($21.90)	$59.22	($109.74)	($104.72)	($106.48)	($116.51)	**($400.12)**	($24.20)
	% Chg		-6.79%	-8.81%	0.78%	-0.24%	-0.24%	46.82%	2.48%	-1.89%	6.01%	-10.29%	-10.25%	-10.26%	-10.34%	**-6.25%**	-0.11%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2011 vs. Actual Summer 2010

Residential Heating	Summer 2010	Summer 2011
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4102	$0.4102
Over 50 therms	$0.2990	$0.2990
LDAC	$0.0297	$0.0456
CGA	$0.6845	$0.6673

	Usage (Therms)	Summer 2010 Bill Amount	Summer 2011 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$15.12	$15.12	($0.01)	0.0%	$0.00	0.0%	($0.09)	-0.6%	$0.08	0.5%
	10	$20.74	$20.73	($0.01)	-0.1%	$0.00	0.0%	($0.17)	-0.8%	$0.16	0.8%
	20	$31.99	$31.96	($0.03)	-0.1%	$0.00	0.0%	($0.34)	-1.1%	$0.32	1.0%
	25	$37.61	$37.58	($0.03)	-0.1%	$0.00	0.0%	($0.43)	-1.1%	$0.40	1.1%
	30	$43.23	$43.19	($0.04)	-0.1%	$0.00	0.0%	($0.52)	-1.2%	$0.48	1.1%
	45	$60.10	$60.04	($0.06)	-0.1%	$0.00	0.0%	($0.77)	-1.3%	$0.72	1.2%
Average Monthly	50	$65.72	$65.66	($0.06)	-0.1%	$0.00	0.0%	($0.86)	-1.3%	$0.80	1.2%
	75	$91.05	$90.95	($0.10)	-0.1%	$0.00	0.0%	($1.29)	-1.4%	$1.19	1.3%
	125	$141.71	$141.55	($0.16)	-0.1%	$0.00	0.0%	($2.15)	-1.5%	$1.99	1.4%
	150	$167.04	$166.85	($0.19)	-0.1%	$0.00	0.0%	($2.58)	-1.5%	$2.39	1.4%
	200	$217.70	$217.44	($0.26)	-0.1%	$0.00	0.0%	($3.44)	-1.6%	$3.18	1.5%

Schedule 9

Unitil
Northern Utilities, Inc.

Northern Utilities New Hampshire Division
Period Covered: May 1, 2011 - October 31, 2011
Variance Analysis

Line		2010 Summer (6 months actual)			Forecast Summer 2011 (6 months proposed)			Variance		
1	Therm Sales	6,609,210			7,400,642			791,432		
2 3 4		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
5										
6	Demand Charges		$1,058,022	$ 0.1601		$1,198,470	$ 0.1619		$ 140,448	$ 0.0019
7										
8	Purchased Gas		3,333,201	0.5043		3,441,521	0.4650		$ 108,320	$(0.0393)
9										
10	Storage & Peaking Gas		34,324	0.0052		25,185	0.0034		$ (9,139)	$(0.0018)
11										
12	Hedging (Gain)/Loss		527,641	0.0798		72,585	0.0098		(455,056)	(0.0700)
13										
14										
15	Total Volumes and Cost	$ -	$4,953,188	$ 0.7494	$ -	$4,737,762	$ 0.6402	$ -	$ (215,426)	$(0.1093)
16										
17	Prior Period Balance		$91,535	$ 0.0138		$ 124,276	$ 0.0168		$ 32,741	$ 0.0029
18	NHPUC Consultant Costs					$ 28,990	$ 0.0039		$ 28,990	$ 0.0039
19	Interest		$ (6,272)	$(0.0009)		2,150	$ 0.0003		8,422	$ 0.0012
20	Refunds from Suppliers		-	$ -		-	$ -		-	$ -
21										
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
24	Capacity Release									
25	Working Capital Allowance		(7,494)	$(0.0011)		(4,824)	$(0.0007)		2,670	$ 0.0005
26	Bad Debt Allowance		3,159	$ 0.0005		25,016	$ 0.0034		21,857	$ 0.0029
27	Fuel Inventory Financing									
28	Local Production and Storage					-	$ -		-	$ -
29	Misc Overhead		28,452	$ 0.0043		25,964	$ 0.0035		(2,488)	$(0.0008)
30										
31	Total Anticipated Indirect Cost of Gas		$109,380	$ 0.0165		201,572	$ 0.0272		92,192	$ 0.0107
32	Total Adjusted Cost	-	5,062,568	$ 0.7660		4,939,334	$ 0.6674		(123,234)	$(0.0986)

Schedule 10A

Unitil
Northern Utilities, Inc.

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

Base Capacity Costs

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
1	**BASE SENDOUT BY CLASS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**	
2	**Total Therms**								
3	Res Heat	398,955	386,086	398,955	371,089	386,086	398,955	2,340,127	Schedule 10B, LN 52
4	Res General	15,958	15,443	13,670	15,958	15,443	15,958	92,431	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	113,572	109,908	95,493	113,572	109,908	113,572	656,026	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	66,910	64,751	45,740	66,910	64,751	66,910	375,972	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	146,213	141,497	129,896	146,213	141,497	146,213	851,530	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	122,197	118,256	89,387	122,197	118,256	122,197	692,490	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	22,076	21,364	22,076	22,018	21,364	22,076	130,975	Schedule 10B, LN 58
10	G42 High Annual-High Winter	11,693	11,315	11,693	11,498	11,315	11,693	69,207	Schedule 10B, LN 59
11	Total Firm Sales	897,575	868,621	806,910	869,455	868,621	897,575	5,208,758	Sum LN 3 : LN 10
12									
13	**% of Total**								
14	Res Heat	44.45%	44.45%	49.44%	42.68%	44.45%	44.45%		LN 3 / LN 11
15	Res General	1.78%	1.78%	1.69%	1.84%	1.78%	1.78%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	12.65%	12.65%	11.83%	13.06%	12.65%	12.65%		LN 5 / LN 11
17	G40 Low Annual-High Winter	7.45%	7.45%	5.67%	7.70%	7.45%	7.45%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	16.29%	16.29%	16.10%	16.82%	16.29%	16.29%		LN 7 / LN 11
19	G41 Med Annual-High Winter	13.61%	13.61%	11.08%	14.05%	13.61%	13.61%		LN 8 / LN 11
20	G52 High Annual-Low Winter	2.46%	2.46%	2.74%	2.53%	2.46%	2.46%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.30%	1.30%	1.45%	1.32%	1.30%	1.30%		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-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 67,859	$ 407,153	Schedule 1A, LN 69
26	Res Heat	$ 30,162	$ 30,162	$ 33,551	$ 28,963	$ 30,162	$ 30,162	$ 183,162	LN 25 * LN 14
27	Res General	$ 1,206	$ 1,206	$ 1,150	$ 1,245	$ 1,206	$ 1,206	$ 7,221	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 8,586	$ 8,586	$ 8,031	$ 8,864	$ 8,586	$ 8,586	$ 51,240	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 5,059	$ 5,059	$ 3,847	$ 5,222	$ 5,059	$ 5,059	$ 29,303	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 11,054	$ 11,054	$ 10,924	$ 11,412	$ 11,054	$ 11,054	$ 66,552	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 9,238	$ 9,238	$ 7,517	$ 9,537	$ 9,238	$ 9,238	$ 54,008	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 1,669	$ 1,669	$ 1,857	$ 1,718	$ 1,669	$ 1,669	$ 10,251	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 884	$ 884	$ 983	$ 897	$ 884	$ 884	$ 5,417	LN 25 * LN 21
34									
35	Residential	$ 31,368	$ 31,368	$ 34,701	$ 30,208	$ 31,368	$ 31,368	$ 190,383	LN 26 + LN 27
36	SALES HLF CLASSES	$ 21,309	$ 21,309	$ 20,811	$ 21,994	$ 21,309	$ 21,309	$ 128,043	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 15,181	$ 15,181	$ 12,347	$ 15,657	$ 15,181	$ 15,181	$ 88,728	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	16,366	1,404	14,962	46.95%	Company Analysis
41	Res General	214	56	158	0.50%	Company Analysis
42	G50 Low Annual-Low Winter	880	346	534	1.67%	Company Analysis
43	G40 Low Annual-High Winter	7,688	263	7,425	23.30%	Company Analysis
44	G51 Med Annual-Low Winter	1,388	492	896	2.81%	Company Analysis
45	G41 Med Annual-High Winter	7,566	443	7,123	22.35%	Company Analysis
46	G52 High Annual-Low Winter	42	24	17	0.05%	Company Analysis
47	G42 High Annual-High Winter	846	94	753	2.36%	Company Analysis
48	TOTAL	34,989	3,122	31,868	100.00%	Sum LN 40 : LN 47
49						

50 **REMAINING PIPELINE DEMAND**

Ln		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 31,168	$ 6,346	$ 825	$ 2,828	$ 9,946	$ 39,025	$ 90,139	Schedule 1A, LN 70
53									
54	Res Heat	$ 14,634	$ 2,979	$ 388	$ 1,328	$ 4,670	$ 18,323	$ 42,321	LN 40 Col D * LN 52
55	Res General	$ 155	$ 31	$ 4	$ 14	$ 49	$ 194	$ 447	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 522	$ 106	$ 14	$ 47	$ 167	$ 654	$ 1,509	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 7,262	$ 1,479	$ 192	$ 659	$ 2,317	$ 9,093	$ 21,002	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 876	$ 178	$ 23	$ 79	$ 280	$ 1,097	$ 2,533	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 6,967	$ 1,418	$ 184	$ 632	$ 2,223	$ 8,723	$ 20,148	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 17	$ 3	$ 0	$ 2	$ 5	$ 21	$ 49	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 736	$ 150	$ 19	$ 67	$ 235	$ 922	$ 2,128	LN 47 Col D * LN 52
62	TOTAL	$ 31,168	$ 6,346	$ 825	$ 2,828	$ 9,946	$ 39,025	$ 90,139	Sum LN 54 : LN 61
63									
64	Residential	$ 14,788	$ 3,011	$ 392	$ 1,342	$ 4,719	$ 18,516	$ 42,768	LN 54 + LN 55
65	SALES HLF CLASSES	$ 1,415	$ 288	$ 37	$ 128	$ 452	$ 1,772	$ 4,092	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 14,965	$ 3,047	$ 396	$ 1,358	$ 4,775	$ 18,737	$ 43,279	LN 57 + LN 59 + LN 61
67									

68 **PEAKING AND STORAGE DEMAND**

Ln		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 242,453	$ 49,362	$ 6,421	$ 22,001	$ 77,369	$ 303,573	$ 701,178	Schedule 1A, LN 73
71									
72	Res Heat	$ 113,833	$ 23,176	$ 3,015	$ 10,330	$ 36,325	$ 142,529	$ 329,207	LN 40 Col D * LN 70
73	Res General	$ 1,203	$ 245	$ 32	$ 109	$ 384	$ 1,507	$ 3,480	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 4,060	$ 827	$ 108	$ 368	$ 1,296	$ 5,084	$ 11,742	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 56,492	$ 11,501	$ 1,496	$ 5,126	$ 18,027	$ 70,733	$ 163,375	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 6,814	$ 1,387	$ 180	$ 618	$ 2,175	$ 8,532	$ 19,707	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 54,192	$ 11,033	$ 1,435	$ 4,918	$ 17,293	$ 67,854	$ 156,726	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 133	$ 27	$ 4	$ 12	$ 42	$ 166	$ 384	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 5,725	$ 1,166	$ 152	$ 520	$ 1,827	$ 7,168	$ 16,557	LN 47 Col D * LN 70
80	TOTAL	$ 242,453	$ 49,362	$ 6,421	$ 22,001	$ 77,369	$ 303,573	$ 701,178	Sum LN 72 : LN 79
81									
82	Residential	$ 115,036	$ 23,421	$ 3,047	$ 10,439	$ 36,709	$ 144,036	$ 332,687	LN 72 + LN 73
83	SALES HLF CLASSES	$ 11,007	$ 2,241	$ 292	$ 999	$ 3,513	$ 13,782	$ 31,833	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 116,409	$ 23,700	$ 3,083	$ 10,563	$ 37,147	$ 145,755	$ 336,658	LN 75 + LN 77 + LN 79
85									

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

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
87									
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 76
89									
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 90 : LN 97
99									
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	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-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
123									
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-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
141									
142	Res Heat	$ 128,466	$ 26,155	$ 3,402	$ 11,657	$ 40,995	$ 160,852	$ 371,528	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 1,358	$ 276	$ 36	$ 123	$ 433	$ 1,700	$ 3,927	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 4,582	$ 933	$ 121	$ 416	$ 1,462	$ 5,737	$ 13,252	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 63,754	$ 12,980	$ 1,688	$ 5,785	$ 20,345	$ 79,826	$ 184,378	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 7,690	$ 1,566	$ 204	$ 698	$ 2,454	$ 9,629	$ 22,240	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 61,159	$ 12,452	$ 1,620	$ 5,550	$ 19,516	$ 76,577	$ 176,873	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 150	$ 31	$ 4	$ 14	$ 48	$ 188	$ 433	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 6,461	$ 1,315	$ 171	$ 586	$ 2,062	$ 8,090	$ 18,686	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 273,621	$ 55,708	$ 7,246	$ 24,829	$ 87,315	$ 342,598	$ 791,317	Sum LN 142 : LN 149
151									
152	Residential	$ 129,824	$ 26,432	$ 3,438	$ 11,781	$ 41,428	$ 162,552	$ 375,455	LN 142 + LN 143
153	SALES HLF CLASSES	$ 12,422	$ 2,529	$ 329	$ 1,127	$ 3,964	$ 15,554	$ 35,926	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 131,374	$ 26,747	$ 3,479	$ 11,921	$ 41,923	$ 164,492	$ 379,936	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER	
157									
158	Res Heat	$ 158,628	$ 56,317	$ 36,953	$ 40,620	$ 71,157	$ 191,014	$ 554,689	LN 142 + LN 26
159	Res General	$ 2,564	$ 1,483	$ 1,186	$ 1,369	$ 1,640	$ 2,907	$ 11,148	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 13,168	$ 9,519	$ 8,152	$ 9,280	$ 10,049	$ 14,324	$ 64,492	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 68,812	$ 18,039	$ 5,535	$ 11,007	$ 25,403	$ 84,884	$ 213,680	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 18,744	$ 12,620	$ 11,128	$ 12,109	$ 13,508	$ 20,683	$ 88,792	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 70,397	$ 21,690	$ 9,137	$ 15,087	$ 28,755	$ 85,815	$ 230,881	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,819	$ 1,700	$ 1,861	$ 1,732	$ 1,717	$ 1,857	$ 10,685	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 7,345	$ 2,199	$ 1,154	$ 1,484	$ 2,946	$ 8,974	$ 24,102	LN 149 + LN 33
166	TOTAL	$ 341,480	$ 123,567	$ 75,105	$ 92,688	$ 155,174	$ 410,457	$ 1,198,470	Sum LN 158 : LN 165
167									
168	Residential	$ 161,193	$ 57,800	$ 38,139	$ 41,989	$ 72,797	$ 193,920	$ 565,838	LN 158 + LN 159
169	SALES HLF CLASSES	$ 33,732	$ 23,839	$ 21,140	$ 23,121	$ 25,274	$ 36,863	$ 163,969	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 146,555	$ 41,928	$ 15,826	$ 27,578	$ 57,104	$ 179,673	$ 468,664	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							26%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							74%	LN 170 / (LN 169 + LN 170)

Schedule 10C

Unitil
Northern Utilities, Inc.

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

Base Commodity Costs

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
1	BASE SENDOUT BY CLASS	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
2	Total Therms							
3	Res Heat	398,955	386,086	398,955	371,089	386,086	398,955	2,340,127
4	Res General	15,958	15,443	13,670	15,958	15,443	15,958	92,431
5	G50 Low Annual-Low Winter	113,572	109,908	95,493	113,572	109,908	113,572	656,026
6	G40 Low Annual-High Winter	66,910	64,751	45,740	66,910	64,751	66,910	375,972
7	G51 Med Annual-Low Winter	146,213	141,497	129,896	146,213	141,497	146,213	851,530
8	G41 Med Annual-High Winter	122,197	118,256	89,387	122,197	118,256	122,197	692,490
9	G52 High Annual-Low Winter	22,076	21,364	22,076	22,018	21,364	22,076	130,975
10	G42 High Annual-High Winter	11,693	11,315	11,693	11,498	11,315	11,693	69,207
11	Total Firm Sales	897,575	868,621	806,910	869,455	868,621	897,575	5,208,758
12	% of Total							
13	Res Heat	44.45%	44.45%	49.44%	42.68%	44.45%	44.45%	
14	Res General	1.78%	1.78%	1.69%	1.84%	1.78%	1.78%	
15	G50 Low Annual-Low Winter	12.65%	12.65%	11.83%	13.06%	12.65%	12.65%	
16	G40 Low Annual-High Winter	7.45%	7.45%	5.67%	7.70%	7.45%	7.45%	
17	G51 Med Annual-Low Winter	16.29%	16.29%	16.10%	16.82%	16.29%	16.29%	
18	G41 Med Annual-High Winter	13.61%	13.61%	11.08%	14.05%	13.61%	13.61%	
19	G52 High Annual-Low Winter	2.46%	2.46%	2.74%	2.53%	2.46%	2.46%	
20	G42 High Annual-High Winter	1.30%	1.30%	1.45%	1.32%	1.30%	1.30%	
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
22	BASE COMMODITY COSTS Excld Hedging	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
23	TOTAL BASE COMMODITY Excld Hedging	$ 403,489	$ 393,256	$ 371,649	$ 405,314	$ 406,642	$ 426,870	$ 2,407,221
24	Res Heat	$ 179,344	$ 174,795	$ 183,752	$ 172,991	$ 180,745	$ 189,736	$ 1,081,362
25	Res General	$ 7,174	$ 6,992	$ 6,296	$ 7,439	$ 7,230	$ 7,589	$ 42,720
26	G50 Low Annual-Low Winter	$ 51,054	$ 49,760	$ 43,983	$ 52,944	$ 51,453	$ 54,013	$ 303,206
27	G40 Low Annual-High Winter	$ 30,078	$ 29,315	$ 21,067	$ 31,191	$ 30,313	$ 31,821	$ 173,786
28	G51 Med Annual-Low Winter	$ 65,728	$ 64,061	$ 59,828	$ 68,160	$ 66,241	$ 69,536	$ 393,554
29	G41 Med Annual-High Winter	$ 54,932	$ 53,539	$ 41,170	$ 56,965	$ 55,361	$ 58,115	$ 320,081
30	G52 High Annual-Low Winter	$ 9,924	$ 9,672	$ 10,168	$ 10,264	$ 10,002	$ 10,499	$ 60,529
31	G42 High Annual-High Winter	$ 5,256	$ 5,123	$ 5,385	$ 5,360	$ 5,297	$ 5,561	$ 31,983
32								
33	Residential	$ 186,517	$ 181,787	$ 190,048	$ 180,430	$ 187,975	$ 197,325	$ 1,124,082
34	SALES HLF CLASSES	$ 126,706	$ 123,493	$ 113,979	$ 131,368	$ 127,696	$ 134,048	$ 757,290
35	SALES LLF CLASSES	$ 90,266	$ 87,977	$ 67,622	$ 93,516	$ 90,971	$ 95,497	$ 525,849

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
36	NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
37	TOTAL BASE HEDGING COMMODITY	$ 24,947	$ -	$ -	$ -	$ -	$ 13,185	$ 38,131
38	Res Heat	$ 11,088	$ -	$ -	$ -	$ -	$ 5,860	$ 16,949
39	Res General	$ 444	$ -	$ -	$ -	$ -	$ 234	$ 678
40	G50 Low Annual-Low Winter	$ 3,157	$ -	$ -	$ -	$ -	$ 1,668	$ 4,825
41	G40 Low Annual-High Winter	$ 1,860	$ -	$ -	$ -	$ -	$ 983	$ 2,843
42	G51 Med Annual-Low Winter	$ 4,064	$ -	$ -	$ -	$ -	$ 2,148	$ 6,212
43	G41 Med Annual-High Winter	$ 3,396	$ -	$ -	$ -	$ -	$ 1,795	$ 5,191
44	G52 High Annual-Low Winter	$ 614	$ -	$ -	$ -	$ -	$ 324	$ 938
45	G42 High Annual-High Winter	$ 325	$ -	$ -	$ -	$ -	$ 172	$ 497
46								
47	Residential	$ 11,532	$ -	$ -	$ -	$ -	$ 6,095	$ 17,627
48	SALES HLF CLASSES	$ 7,834	$ -	$ -	$ -	$ -	$ 4,140	$ 11,974
49	SALES LLF CLASSES	$ 5,581	$ -	$ -	$ -	$ -	$ 2,950	$ 8,531

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

Base Commodity Costs

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

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

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

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

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
51	**Total Therms**							
52	Res Heat	371,839	53,306	27,867	-	69,759	334,768	857,538
53	Res General	7,764	4,289	-	2,288	1,932	5,796	22,070
54	G50 Low Annual-Low Winter	18,942	5,810	-	18,079	16,651	18,917	78,398
55	G40 Low Annual-High Winter	202,390	57,889	-	21,170	54,725	171,456	507,630
56	G51 Med Annual-Low Winter	22,035	6,544	-	16,317	20,927	60,320	126,143
57	G41 Med Annual-High Winter	135,485	59,294	-	32,811	105,052	300,238	632,880
58	G52 High Annual-Low Winter	3,089	1,800	58	-	1,931	5,427	12,304
59	G42 High Annual-High Winter	2,942	1,587	195	-	11,532	23,703	39,958
60	Total Firm Sales	764,485	190,519	28,120	90,665	282,509	920,625	2,276,922
61	**% of Total**							
62	Res Heat	48.64%	27.98%	23.46%	23.46%	24.69%	36.36%	
63	Res General	1.02%	2.25%	1.93%	1.93%	0.68%	0.63%	
64	G50 Low Annual-Low Winter	2.48%	3.05%	15.22%	15.22%	5.89%	2.05%	
65	G40 Low Annual-High Winter	26.47%	30.38%	17.82%	17.82%	19.37%	18.62%	
66	G51 Med Annual-Low Winter	2.88%	3.43%	13.74%	13.74%	7.41%	6.55%	
67	G41 Med Annual-High Winter	17.72%	31.12%	27.62%	27.62%	37.19%	32.61%	
68	G52 High Annual-Low Winter	0.40%	0.94%	0.05%	0.05%	0.68%	0.59%	
69	G42 High Annual-High Winter	0.38%	0.83%	0.16%	0.16%	4.08%	2.57%	
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
72	REMAINING COMMODITY Excld Hedging	$ 344,123	$ 86,844	$ 13,697	$ 43,034	$ 133,077	$ 438,711	$ 1,059,486
73	Res Heat	$ 167,378	$ 24,298	$ 3,213	$ 10,096	$ 32,860	$ 159,529	$ 397,375
74	Res General	$ 3,495	$ 1,955	$ 264	$ 829	$ 910	$ 2,762	$ 10,215
75	G50 Low Annual-Low Winter	$ 8,526	$ 2,648	$ 2,085	$ 6,550	$ 7,844	$ 9,014	$ 36,667
76	G40 Low Annual-High Winter	$ 91,103	$ 26,388	$ 2,441	$ 7,669	$ 25,778	$ 81,705	$ 235,085
77	G51 Med Annual-Low Winter	$ 9,919	$ 2,983	$ 1,882	$ 5,911	$ 9,858	$ 28,745	$ 59,297
78	G41 Med Annual-High Winter	$ 60,987	$ 27,028	$ 3,783	$ 11,887	$ 49,485	$ 143,075	$ 296,245
79	G52 High Annual-Low Winter	$ 1,390	$ 820	$ 7	$ 21	$ 909	$ 2,586	$ 5,734
80	G42 High Annual-High Winter	$ 1,324	$ 723	$ 22	$ 71	$ 5,432	$ 11,295	$ 18,868
81								
82	Residential	$ 170,873	$ 26,254	$ 3,477	$ 10,924	$ 33,770	$ 162,291	$ 407,590
83	SALES HLF CLASSES	$ 19,835	$ 6,452	$ 3,973	$ 12,482	$ 18,611	$ 40,345	$ 101,698
84	SALES LLF CLASSES	$ 153,414	$ 54,139	$ 6,247	$ 19,627	$ 80,695	$ 236,075	$ 550,197

85	**REMAINING COMMODITY HEDGING COSTS**	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	SUMMER
86	TOTAL REMAINING COMMODITY HEDGING	$ 21,037	$ -	$ -	$ -	$ -	$ 13,417	$ 34,454
87	Res Heat	$ 10,232	$ -	$ -	$ -	$ -	$ 4,879	$ 15,111
88	Res General	$ 214	$ -	$ -	$ -	$ -	$ 84	$ 298
89	G50 Low Annual-Low Winter	$ 521	$ -	$ -	$ -	$ -	$ 276	$ 797
90	G40 Low Annual-High Winter	$ 5,569	$ -	$ -	$ -	$ -	$ 2,499	$ 8,068
91	G51 Med Annual-Low Winter	$ 606	$ -	$ -	$ -	$ -	$ 879	$ 1,485
92	G41 Med Annual-High Winter	$ 3,728	$ -	$ -	$ -	$ -	$ 4,376	$ 8,104
93	G52 High Annual-Low Winter	$ 85	$ -	$ -	$ -	$ -	$ 79	$ 164
94	G42 High Annual-High Winter	$ 81	$ -	$ -	$ -	$ -	$ 345	$ 426
95								$ -
96	Residential	$ 10,446	$ -	$ -	$ -	$ -	$ 4,963	$ 15,409
97	SALES HLF CLASSES	$ 1,213	$ -	$ -	$ -	$ -	$ 1,234	$ 2,446
98	SALES LLF CLASSES	$ 9,378	$ -	$ -	$ -	$ -	$ 7,220	$ 16,598

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

Remaining Commodity Costs

LN	Description	Source
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, Inc.
New Hampshire Division
Schedule 10C
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Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
100	TOTAL COMMODITY Excld Hedging	$ 747,612	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 865,581	$ 3,466,707
101	Res Heat	$ 346,722	$ 199,093	$ 186,966	$ 183,086	$ 213,605	$ 349,265	$ 1,478,737
102	Res General	$ 10,669	$ 8,947	$ 6,560	$ 8,268	$ 8,140	$ 10,351	$ 52,935
103	G50 Low Annual-Low Winter	$ 59,581	$ 52,408	$ 46,067	$ 59,493	$ 59,297	$ 63,027	$ 339,874
104	G40 Low Annual-High Winter	$ 121,181	$ 55,703	$ 23,508	$ 38,861	$ 56,092	$ 113,526	$ 408,871
105	G51 Med Annual-Low Winter	$ 75,646	$ 67,044	$ 61,710	$ 74,072	$ 76,099	$ 98,281	$ 452,851
106	G41 Med Annual-High Winter	$ 115,919	$ 80,567	$ 44,953	$ 68,852	$ 104,846	$ 201,189	$ 616,325
107	G52 High Annual-Low Winter	$ 11,314	$ 10,493	$ 10,175	$ 10,285	$ 10,911	$ 13,085	$ 66,263
108	G42 High Annual-High Winter	$ 6,581	$ 5,846	$ 5,408	$ 5,431	$ 10,729	$ 16,856	$ 50,851
109								
110	Residential	$ 357,391	$ 208,040	$ 193,526	$ 191,354	$ 221,745	$ 359,616	$ 1,531,672
111	SALES HLF CLASSES	$ 146,541	$ 129,944	$ 117,952	$ 143,850	$ 146,307	$ 174,393	$ 858,988
112	SALES LLF CLASSES	$ 243,680	$ 142,116	$ 73,869	$ 113,143	$ 171,667	$ 331,572	$ 1,076,047

113	**TOTAL HEDGING COMMODITY COSTS**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
114	TOTAL HEDGING COMMODITY	$ 45,984	$ -	$ -	$ -	$ -	$ 26,602	$ 72,585
115	Res Heat	$ 21,321	$ -	$ -	$ -	$ -	$ 10,739	$ 32,060
116	Res General	$ 657	$ -	$ -	$ -	$ -	$ 319	$ 976
117	G50 Low Annual-Low Winter	$ 3,678	$ -	$ -	$ -	$ -	$ 1,944	$ 5,622
118	G40 Low Annual-High Winter	$ 7,429	$ -	$ -	$ -	$ -	$ 3,482	$ 10,911
119	G51 Med Annual-Low Winter	$ 4,670	$ -	$ -	$ -	$ -	$ 3,027	$ 7,697
120	G41 Med Annual-High Winter	$ 7,125	$ -	$ -	$ -	$ -	$ 6,171	$ 13,295
121	G52 High Annual-Low Winter	$ 699	$ -	$ -	$ -	$ -	$ 403	$ 1,102
122	G42 High Annual-High Winter	$ 406	$ -	$ -	$ -	$ -	$ 517	$ 923
123								
124	Residential	$ 21,978	$ -	$ -	$ -	$ -	$ 11,058	$ 33,036
125	SALES HLF CLASSES	$ 9,046	$ -	$ -	$ -	$ -	$ 5,374	$ 14,421
126	SALES LLF CLASSES	$ 14,959	$ -	$ -	$ -	$ -	$ 10,169	$ 25,129

127	TOTAL COMMODITY	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**SUMMER**
128	Res Heat	$ 368,042	$ 199,093	$ 186,966	$ 183,086	$ 213,605	$ 360,004	$ 1,510,797
129	Res General	$ 11,326	$ 8,947	$ 6,560	$ 8,268	$ 8,140	$ 10,670	$ 53,911
130	G50 Low Annual-Low Winter	$ 63,258	$ 52,408	$ 46,067	$ 59,493	$ 59,297	$ 64,971	$ 345,495
131	G40 Low Annual-High Winter	$ 128,610	$ 55,703	$ 23,508	$ 38,861	$ 56,092	$ 117,008	$ 419,782
132	G51 Med Annual-Low Winter	$ 80,316	$ 67,044	$ 61,710	$ 74,072	$ 76,099	$ 101,308	$ 460,548
133	G41 Med Annual-High Winter	$ 123,043	$ 80,567	$ 44,953	$ 68,852	$ 104,846	$ 207,360	$ 629,621
134	G52 High Annual-Low Winter	$ 12,013	$ 10,493	$ 10,175	$ 10,285	$ 10,911	$ 13,488	$ 67,365
135	G42 High Annual-High Winter	$ 6,987	$ 5,846	$ 5,408	$ 5,431	$ 10,729	$ 17,373	$ 51,774
136	Total Firm Sales	$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 3,539,292
137								
138	Residential	$ 379,368	$ 208,040	$ 193,526	$ 191,354	$ 221,745	$ 370,675	$ 1,564,708
139	SALES HLF CLASSES	$ 155,588	$ 129,944	$ 117,952	$ 143,850	$ 146,307	$ 179,768	$ 873,408
140	SALES LLF CLASSES	$ 258,640	$ 142,116	$ 73,869	$ 113,143	$ 171,667	$ 341,741	$ 1,101,176
141								
142	% ALLOCATION BETWEEN SALES HLF AND LLF							
143	SALES HLF CLASSES							44.23%
144	SALES LLF CLASSES							55.77%

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

Total Commodity Costs

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

Schedule 20

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Northern Utilities, Inc.
Hedging Plan for 2012-13

Schedule 20
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Revised 4/14/2011

		Off-Peak Season		Peak Season								
		May-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	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	04/27/11	1	2	1	1	3	2	2	1	10	3	13
	05/26/11	1	1	1	2	2	2	2	1	10	2	12
	06/28/11	1	1	1	2	2	2	2	1	10	2	12
	07/27/11	1	1	2	1	3	1	2	1	10	2	12
	08/29/11	1	2	1	2	2	2	2	1	10	3	13
	09/28/11	1	1	1	2	2	2	2	2	11	2	13
	10/27/11	2	1	1	2	3	2	1	1	10	3	13
	11/28/11	1	1	1	2	2	2	2	1	10	2	12
	12/28/11	1	2	1	2	2	2	2	1	10	3	13
	01/27/12	1	1	1	1	3	2	2	1	10	2	12
	02/27/12	1	1	1	2	2	2	2	1	10	2	12
	03/28/12	1	1	1	2	2	2	2	2	11	2	13
Make-Up Purchases (white area) Scheduled Sales (gray area)	04/26/12	-13								0	-13	-13
	05/29/12									0	0	0
	06/27/12									0	0	0
	07/27/12									0	0	0
	08/29/12									0	0	0
	09/26/12		-15							0	-15	-15
	10/29/12			-13						-13	0	-13
	11/28/12				-21					-21	0	-21
	12/27/12					-28				-28	0	-28
	01/29/13						-23			-23	0	-23
	02/26/13							-23		-23	0	-23
	03/26/13								-14	-14	0	-14
	Scheduled	13	15	13	21	28	23	23	14	122	28	150
	check	0	0	0	0	0	0	0	0	0	0	0

Northern Utilities, Inc.
3-Year Outlook for Annual Hedging Plans

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 2012			SUMMER 2013			SUMMER 2014		
1	Sendout Requirement (May, Oct)	705,984			750,964			797,089		
2	Financial Hedge Volume	280,000	40%	28	300,000	40%	30	320,000	40%	32
	WINTER PERIOD	WINTER 2012-13			WINTER 2013-14			WINTER 2014-15		
3	Sendout Requirement	5,725,986			5,928,893			6,135,281		
4	Washington 10 Storage	2,543,619	44%		2,543,619	43%		2,543,619	41%	
5	Tennessee Storage	240,755	4%		240,755	4%		240,755	4%	
6	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
7	Financial Hedge Volume	1,220,000	21%	122	1,370,000	23%	137	1,510,000	25%	151
8	Total Hedged Volume	4,004,374	70%		4,154,374	70%		4,294,374	70%	
	HEDGE PLAN YEAR	PLAN YEAR 2012-13			PLAN YEAR 2013-14			PLAN YEAR 2014-15		
9	Financial Hedge Volume	1,500,000	23%	150	1,670,000	25%	167	1,830,000	26%	183

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts
1				
2	SUMMER PERIOD		SUMMER 2011	
3				
4	Sendout Requirement (May, Oct)	656,883		
5	Currently Held Financial Contracts	210,000	32%	21
6	Planned Financial Contracts	90,000	14%	9
7	Total Hedged Volume	300,000	46%	30
8	Target Hedged Volume	260,000	40%	26
9	Projected Position Relative to Target Long/(Short)	40,000	6%	4
10				
11	WINTER PERIOD		WINTER 2011-12	
12				
13	Sendout Requirement	5,563,669		
14	Washington 10 Storage	2,543,619	46%	
15	Tennessee Storage	240,755	4%	
16	Fixed Price Physical Contracts	0	0%	
17	Currently Held Financial Contracts	640,000	12%	64
18	Planned Financial Contracts	320,000	6%	32
19	Total Hedged Volume	3,744,374	67%	
20	Target Financial Hedge	3,890,000	70%	
21	Projected Position Relative to Target Long/(Short)	-150,000	-3%	-15

Schedule 21

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Northern Utilities, Inc.

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

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 8,281,964
Storage Demand	$ 29,019,569
Peaking Demand	$ 5,855,525
Subtotal Demand	$ 43,157,058
Litigation Expense - PNGTS Invoices from 9/1/2009 - 8/13/2010	$ 376,840
Capacity Release (Credit)	$ (424,530)
Asset Management (Credit)	$ (2,507,000)
Total Net Demand Costs	$ 40,602,368

Proportional Responsibility (PR) Allocators

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

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
Rank	4	2	1	6	3	5	8	9	12	11	10	7	
% Max Month	96.85%	100.00%	100.00%	90.32%	98.51%	94.19%	86.61%	60.01%	51.03%	54.37%	58.89%	89.57%	
PR	0.66%	0.75%	0.00%	0.13%	0.55%	0.77%	3.32%	0.12%	4.25%	0.30%	0.45%	0.42%	11.74%
CumPR	10.44%	11.74%	11.74%	9.01%	11.00%	9.78%	8.46%	5.13%	4.25%	4.56%	5.01%	8.88%	100.00%
Product and Pipeline Demand Costs	$ 865,013	$ 972,513	$ 972,513	$ 745,865	$ 910,773	$ 809,993	$ 700,403	$ 425,056	$ 352,225	$ 377,367	$ 414,797	$ 735,447	$ 8,281,964

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	5,234	554,104	556,770	575,329	574,118	556,770	551,826	3,374,152
Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	47.0%	56.2%	61.0%	59.4%	56.7%	46.0%	32.3%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 6,187	$ 329,067	$ 239,044	$ 214,714	$ 224,118	$ 235,186	$ 338,625	$ 1,586,940

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	135,581	686,913	1,016,879	728,568	633,976	190,867	24,831	-	-	-	-	17,189	3,434,803
Rank	6	3	1	2	4	5	7	9	9	9	9	8	
% Max Month	13.33%	67.55%	100.00%	71.65%	62.35%	18.77%	2.44%	0.00%	0.00%	0.00%	0.00%	1.69%	
PR	1.82%	1.74%	28.35%	2.05%	10.89%	1.09%	0.11%	0.00%	0.00%	0.00%	0.00%	0.21%	46.25%
CumPR	2.13%	15.85%	46.25%	17.90%	14.12%	3.22%	0.32%	0.00%	0.00%	0.00%	0.00%	0.21%	100.00%
Storage Demand Costs	$ 619,236	$ 4,599,698	$ 13,421,863	$ 5,194,075	$ 4,096,129	$ 934,782	$ 92,472	$ -	$ -	$ -	$ -	$ 61,316	$ 29,019,569
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 6,187	$ 329,067	$ 239,044	$ 214,714	$ 224,118	$ 235,186	$ 338,625	$ 1,586,940
TOTAL	$ 619,236	$ 4,599,698	$ 13,421,863	$ 5,194,075	$ 4,096,129	$ 940,968	$ 421,539	$ 239,044	$ 214,714	$ 224,118	$ 235,186	$ 399,941	$ 30,606,509

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	134,340	128,242	199,339	162,905	111,881	139,911	16,142	1,350	1,395	1,395	1,350	3,873	902,124
Rank	4	5	1	2	6	3	7	12	10	9	11	8	
% Max Month	67.39%	64.33%	100.00%	81.72%	56.13%	70.19%	8.10%	0.68%	0.70%	0.70%	0.68%	1.94%	
PR	0.76%	1.64%	18.28%	5.77%	8.00%	0.93%	0.88%	0.06%	0.00%	0.00%	0.00%	0.16%	36.48%
CumPR	11.50%	10.74%	36.48%	18.20%	9.10%	12.44%	1.09%	0.06%	0.06%	0.06%	0.06%	0.21%	100.00%
Peaking Demand Costs	$ 673,642	$ 628,861	$ 2,136,136	$ 1,065,914	$ 532,742	$ 728,193	$ 64,019	$ 3,305	$ 3,437	$ 3,437	$ 3,305	$ 12,536	$ 5,855,525

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

LN		
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**

LN		
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**

LN		
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**

LN		
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**

LN		
43		
44	Design Year Peaking Volumes	Company Analysis
45	Rank	Rank LN 44
46	% Max Month	LN 44 / LN 44 MAX
47	PR	The difference between LN 46 for the month and LN 46 for next highest rank
48	CumPR	Cumulative Values, LN 47
49	Peaking Demand Costs	LN 48 * LN 5

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

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
50	Pipeline & Product Demand	$ 865,013	$ 972,513	$ 972,513	$ 745,865	$ 910,773	$ 809,993	$ 700,403	$ 425,056	$ 352,225	$ 377,367	$ 414,797	$ 735,447	$ 8,281,964
51	Storage Incld Inj Fees	$ 619,236	$ 4,599,698	$ 13,421,863	$ 5,194,075	$ 4,096,129	$ 940,968	$ 421,539	$ 239,044	$ 214,714	$ 224,118	$ 235,186	$ 399,941	$ 30,606,509
52	Peaking	$ 673,642	$ 628,861	$ 2,136,136	$ 1,065,914	$ 532,742	$ 728,193	$ 64,019	$ 3,305	$ 3,437	$ 3,437	$ 3,305	$ 12,536	$ 5,855,525
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (6,187)	$ (329,067)	$ (239,044)	$ (214,714)	$ (224,118)	$ (235,186)	$ (338,625)	$ (1,586,940)
54	Less: Capacity Release	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (424,530)
55	Less: Asset Mgmt net of Current PNGTS	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,130,160)
56	Total Demand	$ 1,717,959	$ 5,761,138	$ 16,090,579	$ 6,565,920	$ 5,099,711	$ 2,117,941	$ 856,894	$ 428,361	$ 355,662	$ 380,803	$ 418,102	$ 809,298	$ 40,602,368

57

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

59		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
60	**Therms**													
61	Maine	512,441	802,081	984,724	779,373	729,594	512,543	334,300	199,982	211,643	224,651	216,214	361,107	5,868,653
62	New Hampshire	451,012	725,852	941,537	754,644	718,372	492,061	327,795	231,682	156,234	167,196	207,705	302,779	5,476,869
63	Total	963,453	1,527,933	1,926,261	1,534,017	1,447,966	1,004,604	662,095	431,664	367,877	391,847	423,919	663,886	11,345,522

64	**Percentage of Total**	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
65	Maine	53.19%	52.49%	51.12%	50.81%	50.39%	51.02%	50.49%	46.33%	57.53%	57.33%	51.00%	54.39%	51.37%
66	New Hampshire	46.81%	47.51%	48.88%	49.19%	49.61%	48.98%	49.51%	53.67%	42.47%	42.67%	49.00%	45.61%	48.63%
67	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

68

69 **Allocation of Demand Costs by Division**

70	Maine	$913,748	$3,024,282	$8,225,666	$3,335,883	$2,569,617	$1,080,561	$432,656	$198,452	$204,615	$218,320	$213,247	$440,201	$20,857,247
71	New Hampshire	$804,212	$2,736,857	$7,864,913	$3,230,037	$2,530,094	$1,037,380	$424,237	$229,909	$151,046	$162,484	$204,855	$369,097	$19,745,121
72	Total	$ 1,717,959	$ 5,761,138	$ 16,090,579	$ 6,565,920	$ 5,099,711	$ 2,117,941	$ 856,894	$ 428,361	$ 355,662	$ 380,803	$ 418,102	$ 809,298	$ 40,602,368

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

74	**Maine**	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	
75	Pipeline & Product Demand	$ 460,083	$ 510,516	$ 497,158	$ 378,944	$ 458,916	$ 413,254	$ 353,642	$ 196,921	$ 202,638	$ 216,349	$ 211,561	$ 400,031	$ 4,300,013	51.92%
76	Storage Incld Injection Fees	$ 329,359	$ 2,414,589	$ 6,861,391	$ 2,638,903	$ 2,063,937	$ 480,077	$ 212,840	$ 110,744	$ 123,527	$ 128,490	$ 119,953	$ 217,539	$ 15,701,350	51.30%
77	Peaking	$ 358,297	$ 330,117	$ 1,092,014	$ 541,548	$ 268,436	$ 371,520	$ 32,324	$ 1,531	$ 1,977	$ 1,970	$ 1,685	$ 6,818	$ 3,008,238	51.37%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (3,156)	$ (166,150)	$ (110,744)	$ (123,527)	$ (128,490)	$ (119,953)	$ (184,188)	$ (836,209)	
79	Capacity Release (Credit)	$ (45,160)	$ (44,571)	$ (43,405)	$ (43,137)	$ (42,782)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (219,055)	51.60%
80	Asset Management - PNGTS (Credit)	$ (188,831)	$ (186,370)	$ (181,493)	$ (180,375)	$ (178,889)	$ (181,132)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,097,091)	51.50%
81	**Total Allocated Demand**	$ 913,748	$ 3,024,282	$ 8,225,666	$ 3,335,883	$ 2,569,617	$ 1,080,561	$ 432,656	$ 198,452	$ 204,615	$ 218,320	$ 213,247	$ 440,201	$ 20,857,247	51.37%

82

83	**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	
84	Pipeline & Product Demand	$ 404,930	$ 461,997	$ 475,354	$ 366,921	$ 451,857	$ 396,740	$ 346,761	$ 228,135	$ 149,587	$ 161,017	$ 203,235	$ 335,416	$ 3,981,950	48.08%
85	Storage Incld Injection Fees	$ 289,877	$ 2,185,109	$ 6,560,472	$ 2,555,172	$ 2,032,191	$ 460,892	$ 208,699	$ 128,299	$ 91,187	$ 95,628	$ 115,233	$ 182,401	$ 14,905,160	48.70%
86	Peaking	$ 315,346	$ 298,743	$ 1,044,122	$ 524,365	$ 264,307	$ 356,673	$ 31,695	$ 1,774	$ 1,460	$ 1,466	$ 1,619	$ 5,717	$ 2,847,287	48.63%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (3,030)	$ (162,917)	$ (128,299)	$ (91,187)	$ (95,628)	$ (115,233)	$ (154,437)	$ (750,731)	
88	Capacity Release	$ (39,746)	$ (40,335)	$ (41,501)	$ (41,769)	$ (42,124)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (205,475)	48.40%
89	Asset Management - PNGTS (Credit)	$ (166,195)	$ (168,657)	$ (173,533)	$ (174,652)	$ (176,138)	$ (173,894)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,033,069)	48.50%
90	**Total Allocated Demand**	$ 804,212	$ 2,736,857	$ 7,864,913	$ 3,230,037	$ 2,530,094	$ 1,037,380	$ 424,237	$ 229,909	$ 151,046	$ 162,484	$ 204,855	$ 369,097	$ 19,745,121	48.63%

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

Line		
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

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Northern Utilities, Inc.

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	304,244	188,838	139,235	176,289	216,266	349,849	3,621,221	1,374,721
3	Total Storage	0	0	0	0	0	0	2,488,619	0
4	Total Peaking	1,395	1,350	1,395	1,395	1,350	1,395	629,141	8,280
5	Subtotal	305,639	190,188	140,630	177,684	217,616	351,244	6,738,982	1,383,001
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	305,639	190,188	140,630	177,684	217,616	351,244	6,738,982	1,383,001
9	Total Firm Pipeline Sendout	304,244	188,838	139,235	176,289	216,266	349,849	3,621,221	1,374,721
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 1,549,919	$ 961,254	$ 715,227	$ 911,185	$ 1,119,926	$ 1,837,342	$ 17,695,161	$ 7,094,853
12	NYMEX Price Used for Forecast	$4.707	$4.739	$4.791	$4.816	$4.821	$4.869		
13	NYMEX Price Used for Update	$4.108	$4.176	$4.260	$4.309	$4.324	$4.373		
14	Increase/(Decrease) NYMEX Price	-$0.599	-$0.563	-$0.531	-$0.507	-$0.497	-$0.496		
15	Increase/(Decrease) in Pipeline Costs	$ (182,242)	$ (106,316)	$ (73,934)	$ (89,379)	$ (107,484)	$ (173,525)		
16	Total Updated Pipeline Costs	$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	$ 16,962,281	$ 6,361,973
17									
18	Total Pipeline	$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	$ 16,962,281	$ 6,361,973
19	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,895,622	$ -
20	Total Peaking	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 2,457,873	$ 46,101
21	Subtotal	$ 1,374,797	$ 862,108	$ 648,974	$ 829,731	$ 1,020,314	$ 1,672,150	$ 30,315,777	$ 6,408,074
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	14	-	-	-	-	9	61	23
26	Average Purchase Price	$ 4.712	$ -	$ -	$ -	$ -	$ 4.944		
27	NYMEX Price Used for Forecast	$ 4.707	$ 4.739	$ 4.791	$ 4.816	$ 4.821	$ 4.869		
28	NYMEX Price Used for Update	$ 4.108	$ 4.176	$ 4.260	$ 4.309	$ 4.324	$ 4.373		
29	Increase/(Decrease) NYMEX Price	$ (0.599)	$ (0.563)	$ (0.531)	$ (0.507)	$ (0.497)	$ (0.496)		
30	Futures Hedging (Gain)/Loss - Allocate	$ 84,560	$ -	$ -	$ -	$ -	$ 51,390	$ 1,021,610	$ 135,950
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	28	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 4.707	$ 4.739	$ 4.791	$ 4.816	$ 4.821	$ 4.869		
35	NYMEX Price Used for Update	$ 4.108	$ 4.176	$ 4.260	$ 4.309	$ 4.324	$ 4.373		
36	Increase/(Decrease) NYMEX Price	$ (0.599)	$ (0.563)	$ (0.531)	$ (0.507)	$ (0.497)	$ (0.496)		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ 654,620	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	$ 16,962,281	$ 6,361,973
41	Average Supply Cost ($/MMBtu)	$ 4.495	$ 4.527	$ 4.606	$ 4.662	$ 4.681	$ 4.756		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	$ 16,962,281	$ 6,361,973
46	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,895,622	$ -
47	Total Peaking	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 2,457,873	$ 46,101
48	Firm Sales Variable Costs Excld Hedge	$ 1,374,797	$ 862,108	$ 648,974	$ 829,731	$ 1,020,314	$ 1,672,150	$ 30,315,777	$ 6,408,074
49	Plus Hedging (Gain)/Loss	$ 84,560	$ -	$ -	$ -	$ -	$ 51,390	$ 1,021,610	$ 135,950
50	Total Firm Sales Variable Costs	$ 1,459,357	$ 862,108	$ 648,974	$ 829,731	$ 1,020,314	$ 1,723,540	$ 31,337,387	$ 6,544,024

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Attachment NUI-FXW-6, page 2
3	Total Storage	Attachment NUI-FXW-6, page 2
4	Total Peaking	Attachment NUI-FXW-6, page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Attachment NUI-FXW-6, page 2
7	Less Interruptible - New Hampshire	Attachment NUI-FXW-6, page 2
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Attachment NUI-FXW-6, page 1
12	NYMEX Price Used for Forecast	Attachment NUI-FXW-7A
13	NYMEX Price Used for Update	Attachment NUI-FXW-7A
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Attachment NUI-FXW-6, page 1
20	Total Peaking	Attachment NUI-FXW-6, page 1
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Attachment NUI-FXW-9
26	Average Purchase Price	Attachment NUI-FXW-9
27	NYMEX Price Used for Forecast	Attachment NUI-FXW-7A
28	NYMEX Price Used for Update	Company Analysis
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Attachment NUI-FXW-9
33	Average Purchase Price	Attachment NUI-FXW-9
34	NYMEX Price Used for Forecast	Attachment NUI-FXW-9
35	NYMEX Price Used for Update	Company Analysis
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

Line		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
51	**Commodity Allocation Factors**								
52	Firm Sales Sendout for Normal Winter, MMBtu								
53		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	SUMMER
54	Maine	139,433	84,274	57,127	81,672	102,503	169,424	3,157,582	634,433
55	New Hampshire	166,206	105,914	83,503	96,012	115,113	181,820	3,581,400	748,568
56	Total	305,639	190,188	140,630	177,684	217,616	351,244	6,738,982	1,383,001
57									
58	**Percentage of Total**								
59	Maine	45.62%	44.31%	40.62%	45.96%	47.10%	48.24%	46.86%	45.87%
60	New Hampshire	54.38%	55.69%	59.38%	54.04%	52.90%	51.76%	53.14%	54.13%
61	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
62									
63	**Commodity Allocation by Jurisdiction**								
64	**Maine**								
65	Firm Sales Pipeline Commodity Excld Hedge	$ 623,936	$ 378,831	$ 260,507	$ 377,741	$ 476,887	$ 802,549	$ 7,932,287	$ 2,920,452
66	Hedging (Gains) Losses	$ 38,576	$ -	$ -	$ -	$ -	$ 24,788	$ 482,943	$ 63,365
67	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,114,409	$ -
68	Peaking	$ 3,248	$ 3,177	$ 3,120	$ 3,643	$ 3,708	$ 4,019	$ 1,156,889	$ 20,916
69	Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Total Maine Commodity Costs	$ 665,761	$ 382,008	$ 263,628	$ 381,384	$ 480,595	$ 831,357	$ 14,686,528	$ 3,004,732
71	Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,948	$ -
72	Total Maine Variable Costs	$ 665,761	$ 382,008	$ 263,628	$ 381,384	$ 480,595	$ 831,357	$ 14,695,476	$ 3,004,732
73	**New Hampshire**								
74	Firm Sales Pipeline Commodity Excld Hedge	$ 743,740	$ 476,107	$ 380,786	$ 444,065	$ 535,555	$ 861,268	$ 9,029,995	$ 3,441,521
75	Hedging (Gains) Losses	$ 45,984	$ -	$ -	$ -	$ -	$ 26,602	$ 1,193,287	$ 72,585
76	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,781,213	$ -
77	Peaking	$ 3,872	$ 3,993	$ 4,561	$ 4,282	$ 4,164	$ 4,314	$ 1,300,984	$ 25,185
78	New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total New Hampshire Commodity Costs	$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 17,305,479	$ 3,539,292
80	New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,276	$ -
81	Total New Hampshire Variable Costs	$ 793,596	$ 480,100	$ 385,347	$ 448,347	$ 539,719	$ 892,183	$ 17,315,755	$ 3,539,292
82	**Northern Utilities**								
83	Firm Sales Pipeline Commodity Excld Hedge	$ 1,367,677	$ 854,938	$ 641,293	$ 821,806	$ 1,012,442	$ 1,663,817	$ 16,962,281	$ 6,361,973
84	Hedging (Gains) Losses	$ 84,560	$ -	$ -	$ -	$ -	$ 51,390	$ 1,676,230	$ 135,950
85	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,895,622	$ -
86	Peaking	$ 7,120	$ 7,170	$ 7,681	$ 7,925	$ 7,872	$ 8,333	$ 2,457,873	$ 46,101
87	Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Total Northern Commodity Costs	$ 1,459,357	$ 862,108	$ 648,974	$ 829,731	$ 1,020,314	$ 1,723,540	$ 31,992,007	$ 6,544,024
89	Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,224	$ -
90	Total Northern Variable Costs	$ 1,459,357	$ 862,108	$ 648,974	$ 829,731	$ 1,020,314	$ 1,723,540	$ 32,011,231	$ 6,544,024
91									

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51	**Commodity Allocation Factors**	
52	Firm Sales Sendout for Normal Winter, MMBtu	
53		
54	Maine	ME Attachment NUI-JDS-4, LN 33 / 10
55	New Hampshire	Company Analysis
56	Total	LN 54 + LN 55
57		
58	**Percentage of Total**	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60
62		
63	**Commodity Allocation by Jurisdiction**	
64	**Maine**	
65	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 59
66	Hedging (Gains) Losses	LN 30 * LN 59
67	Storage	LN 46 * LN 59
68	Peaking	LN 47 * LN 59
69	Maine Interruptible	LN 42
70	Total Maine Commodity Costs	Sum LN 65 : LN 69
71	Maine Inventory Finance Costs	LN 112
72	Total Maine Variable Costs	LN 70 + LN 71
73	**New Hampshire**	
74	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60 + LN 37
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-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**TOTAL**	**SUMMER**
Storage	$ 255	$ 759	$ 1,267	$ 1,733	$ 1,939	$ 1,939	$ 17,868	$ 7,893
Peaking	$ 90	$ 101	$ 105	$ 109	$ 112	$ 115	$ 1,356	$ 632
Total	$ 346	$ 861	$ 1,372	$ 1,842	$ 2,051	$ 2,054	$ 19,224	$ 8,524
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 158	$ 381	$ 557	$ 846	$ 966	$ 991	$ 8,948	$ 3,899
New Hampshire	$ 188	$ 479	$ 815	$ 995	$ 1,085	$ 1,063	$ 10,276	$ 4,625
Total	$ 346	$ 861	$ 1,372	$ 1,842	$ 2,051	$ 2,054	$ 19,224	$ 8,524

Inventory Finance Charge Allocation by Month

Maine								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,117,945	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	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,948	$ -
New Hampshire								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,315,531	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	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,276	$ -

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

Line		
98	**Inventory Finance Charge**	
99	Storage	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
100	Peaking	Company Analysis, Attachment NUI-JDS-8 - '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	ME Attachment NUI-JDS-4, LN 80 / 10
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111
113		
114	**New Hampshire**	
115	Firm Sales Remaining Sendout	Company Analysis
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

Unitil
Northern Utilities, Inc.

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

LN		Winter	Summer	Total	
1	Demand	$ 15,043,530	$ 1,198,470	$ 16,242,000	Schedule 1A, LN 80
2	Commodity	$ 13,776,463	$ 3,539,292	$ 17,315,755	Schedule 1B, LN 0
3	Total	$ 28,819,993	$ 4,737,762	$ 33,557,755	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,028,950	7,400,642	35,429,591	Schedule 10B, LN 11 * 10
6	Forecasted Residential Sales (Therms)	13,035,240	3,274,690	16,309,931	Schedule 10B, LN 3 * 10
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.5367	$0.1619		LN 1 / LN 5
9	Average Commodity Rate	$0.4915	$0.4782		LN 2 / LN 5
10	Average Rate	$1.0282	$0.6402		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 7,135,172	$ 565,838	$ 7,701,010	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,996,196	$ 530,172	$ 7,526,369	LN 8 * LN 6
15	**Demand Reallocation:**	$ 138,976	$ 35,665	$ 174,641	LN 13 - LN 14
16	**HLF Allocation**	$ 13,860	$ 9,244	$ 23,104	LN 15 / LN 20
17	**LLF Allocation**	$ 125,116	$ 26,421	$ 151,537	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	9.97%	25.92%		Schedule 10A, LN 173
21	LLF	90.03%	74.08%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 6,408,561	$ 1,564,708	$ 7,973,269	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 6,406,930	$ 1,565,957	$ 7,972,886	LN 18 * LN 16
25	**Commodity Reallocation:**	$ 1,632	$ (1,249)	$ 383	LN 23 - LN 24
26	**HLF Allocation**	$ 291	$ (553)	$ (262)	LN 25 / LN 30
27	**LLF Allocation**	$ 1,341	$ (697)	$ 644	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	17.82%	44.23%		Schedule 10C, LN 143
31	LLF	82.18%	55.77%		Schedule 10C, LN 144