ENERGY NORTH NATURAL GAS, INC. REDACTED VERSION
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing

Table of Contents

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Summary

Line	(a)	Reference (b)	Peak Nov - Apr (c)
9	**Anticipated Direct Cost of Gas**		
10	Purchased Gas:		
11	Demand Costs:	Sch. 5A, col (k), ln 43	$ 6,500,887
12	Supply Costs	Sch. 6, col (i), ln 43	79,707,811
14	Storage Gas:		
15	Demand, Capacity:	Sch. 5A, col (k), ln 58	$ 1,171,446
16	Commodity Costs:	Sch. 6, col (i), ln 46	16,341,221
18	Produced Gas:	Sch. 6, col (i), ln 52	$ 2,665,995
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 32	$ 2,524,964
22	**Total Unadjusted Cost of Gas**		$ 108,912,324
24	**Adjustments:**		
26	Prior Period (Over)/Under Recovery	Sch. 3, col (c) ln 26	$ 2,883,321
27	Interest May 1, 2008 - April 30, 2009	Sch. 3, col (q) ln 168	336,795
28	Prior Period Adjustments	Sch. 4, ln 24 col (b)	-
29	Refunds from Suppliers	Sch. 4, ln 24 col (c)	-
30	Broker Revenues	Sch. 4, ln 24 col (d)	(1,249,699)
31	Fuel Financing	Sch. 4, ln 24 col (e)	526,256
32	Transportation CGA Revenues	Sch. 4, ln 24 col (f)	(5,004)
33	Interruptible Sales Margin	Sch. 4, ln 26 col (g)	(2,245)
34	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)	(410,806)
35	Hedging Costs	Sch. 4, ln 24 col (j)	-
36	Fixed Price Option Administrative Costs	Sch. 4, ln 24 col (k)	36,312
38	**Total Adjustments**		$ 2,114,930
40	**Total Anticipated Direct Costs**	lns 22 + 38	$ 111,027,254
42	**Anticipated Indirect Cost of Gas**		
43	**Working Capital**		
44	Total Anticipated Direct Cost of Gas	Sch 3, ln 32	$ 108,912,324
45	Working Capital Percentage	per GTC 16(f)	0.645%
46	Working Capital	ln 44 * ln 45	702,484
47	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 85	(305,654)
49	**Total Working Capital Allowance**	lns 46 + 47	$ 396,830
51	**Bad Debt**		
52	Total Anticipated Direct Cost of Gas	ln 44	$ 108,912,324
53	Less Refunds		-
54	Plus Working Capital	ln 49	396,830
55	Plus Prior Period (Over) Under Recovery	ln 26	2,883,321
56	Subtotal		$ 112,192,475
57	Bad Debt Percentage	per GTC 16(f)	1.75%
59	Bad Debt Allowance	ln 56 * ln 57	$ 1,963,368
60	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 141	(1,409,904)
62	**Total Bad Debt Allowance**	lns 59 + 60	$ 553,464
64	**Production and Storage Capacity**	per GTC16(f)	$ 2,105,212
66	**Miscellaneous Overhead**	per GTC 16(f)	$ 135,339
67	Sales Volume	Sch. 10B, ln 24/1000	89,931
68	Divided by Total Sales	Sch. 10B, ln 24/1000	112,874
69	Ratio		79.67%
71	**Miscellaneous Overhead**	lns 66 * 69	$ 107,829
73	**Total Anticipated Indirect Cost of Gas**	lns 49 + 62 + 64 + 71	$ 3,163,335
75	**Total Cost of Gas**	lns 40 * 73	$ 114,190,590
77	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 47	90,372,901

Ln										
1	**ENERGY NORTH NATURAL GAS, INC.**									
2	**d/b/a National Grid NH**									
3	**Peak 2008 - 2009 Winter Cost of Gas Filing**									
4	**Summary of Supply and Demand Forecast**									
5										
6			Peak Costs							Peak Period
7	For Month of:		May 08 - Oct 08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
9	**I. Gas Volumes (Therms)**									
10										
11	**A. Firm Demand Volumes**									
12	Firm Gas Sales	Sch. 10B, ln 24	-	7,621,275	15,151,339	18,564,916	19,235,755	16,626,366	12,730,891	89,930,543
13	Lost Gas (Unaccounted for)		-	294,040	445,572	523,339	431,176	381,049	227,451	2,302,627
14	Company Use		-	29,256	44,333	52,071	42,901	37,913	22,631	229,104
15	Unbilled Therms		-	4,233,793	2,813,198	2,535,019	(1,851,652)	(1,263,263)	(3,560,551)	2,906,544
16										
17	**Total Firm Volumes**	Sch. 6, ln 91	-	12,178,365	18,454,442	21,675,346	17,858,179	15,782,065	9,420,421	95,368,818
18										
19	**B. Supply Volumes (Therms)**									
20	Pipeline Gas:									
21	Dawn Supply	Sch. 6, ln 62	-	1,065,528	1,100,655	1,100,655	994,373	1,100,655	1,068,230	6,430,097
22	Niagara Supply	Sch. 6, ln 63	-	843,956	871,878	871,878	787,212	871,878	843,956	5,090,756
23	TGP Supply (Direct)	Sch. 6, ln 64	-	5,835,635	5,624,872	5,945,521	5,262,790	6,030,187	5,835,635	34,534,639
24	TGP Zone 6 Purchases	Sch. 6, ln 65	-	-	-	-	-	-	1,052,918	1,052,918
25	Dracut Winter Supply	Sch. 6, ln 66	-	1,054,720	5,488,866	5,494,270	4,953,850	370,188	-	17,361,893
26	City Gate Delivered Supply	Sch. 6, ln 67	-	2,161,680	2,233,736	2,233,736	2,017,568	915,111	1,001,578	10,563,410
27	LNG Truck	Sch. 6, ln 68	-	225,175	237,785	360,280	302,635	225,175	-	1,351,050
28	Propane Truck	Sch. 6, ln 69	-	-	-	562,938	-	-	-	562,938
29	PNGTS	Sch. 6, ln 70	-	29,723	38,730	44,134	37,829	34,227	25,220	209,863
30	Granite Ridge	Sch. 6, ln 71	-	-	-	-	-	-	-	-
31	Subtotal Pipeline Volumes		-	11,216,417	15,596,521	16,613,412	14,356,257	9,547,420	9,827,538	77,157,565
32										
33	Storage Gas:									
34	TGP Storage	Sch. 6, ln 76	-	1,730,245	2,761,546	5,006,091	3,325,384	6,241,851	-	19,065,117
35										
36	Produced Gas:									
37	LNG Vapor	Sch. 6, ln 79	-	225,175	237,785	416,123	288,224	217,969	25,220	1,410,496
38	Propane	Sch. 6, ln 80	-	-	96,375	562,938	190,948	-	-	850,261
39	Subtotal Produced Gas		-	225,175	334,160	979,061	479,172	217,969	25,220	2,260,757
40										
41	Less - Gas Refill:									
42	LNG Truck	Sch. 6, ln 85	-	(225,175)	(237,785)	(360,280)	(302,635)	(225,175)	-	(1,351,050)
43	Propane	Sch. 6, ln 86	-	-	-	(562,938)	-	-	-	(562,938)
44	TGP Storage Refill	Sch. 6, ln 87	-	(768,297)	-	-	-	-	(432,336)	(1,200,633)
45	Subtotal Refills		-	(993,472)	(237,785)	(923,218)	(302,635)	(225,175)	(432,336)	(3,114,621)
46										
47	Total Firm Sendout Volumes		-	12,178,365	18,454,442	21,675,346	17,858,179	15,782,065	9,420,421	95,368,818
48										

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1	**ENERGY NORTH NATURAL GAS, INC.**									
2	**d/b/a National Grid NH**									
3	**Peak 2008 - 2009 Winter Cost of Gas Filing**									
4	**Summary of Supply and Demand Forecast**									
5										
6			Peak Costs							Peak Period
7	For Month of:		May 08 - Oct 08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov - Apr
49	**II. Gas Costs**									
50										
51	**A. Demand Costs**									
52	Supply									
53	Niagra Supply	Sch.5A, ln 12								
54	Subtotal Supply Demand									
55	Less Capacity Credit									
56	Net Pipeline Demand Costs									
57										
58	Pipeline:									
59	Iroquois Gas Trans Service RTS 470	Sch.5A, ln 16	$ -	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 160,191
60	Tenn Gas Pipeline 33371	Sch.5A, ln 17	-	42,440	42,440	42,440	42,440	42,440	42,440	254,640
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18	-	15,391	15,391	15,391	15,391	15,391	15,391	92,349
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19	-	116,711	116,711	116,711	116,711	116,711	116,711	700,264
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20	-	220,599	220,599	220,599	220,599	220,599	220,599	1,323,595
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21	-	22,447	22,447	22,447	22,447	22,447	22,447	134,681
65	Tenn Gas Pipeline (Dracut) 42076 Z(	Sch.5A, ln 22	-	63,200	63,200	63,200	63,200	63,200	63,200	379,200
66	Portland Natural Gas Trans Service	Sch.5A, ln 23	-	27,402	27,402	27,402	27,402	27,402	27,402	164,410
67	ANE (TransCanada via Union to Iroq	Sch.5A, ln 24	-	39,557	39,557	39,557	39,557	39,557	39,557	237,340
68	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 25	539,465	89,911	89,911	89,911	89,911	89,911	89,911	1,078,930
69	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 26	250,278	41,713	41,713	41,713	41,713	41,713	41,713	500,556
70	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 27	57,888	9,648	9,648	9,648	9,648	9,648	9,648	115,776
71	National Fuel FST 2358	Sch.5A, ln 28	122,980	20,497	20,497	20,497	20,497	20,497	20,497	245,959
72	Subtotal Pipeline Demand		$ 970,611	$ 736,213	$ 736,213	$ 736,213	$ 736,213	$ 736,213	$ 736,213	$ 5,387,890
73	Less Capacity Credit		(91,772)	(73,117)	(73,117)	(73,117)	(73,117)	(73,117)	(73,117)	(530,474)
74	Net Pipeline Demand Costs		$ 878,839	$ 663,096	$ 663,096	$ 663,096	$ 663,096	$ 663,096	$ 663,096	$ 4,857,416
75										
76	Peaking Supply:									
77	Granite Ridge Demand	Sch.5A, ln 33								
78	DOMAC Liquid FLS-164	Sch.5A, ln 34								
79	DOMAC Demand FLS-160	Sch.5A, ln 35								
80	Transgas Trucking	Sch.5A, ln 36								
81	Subtotal Peaking Demand		$ 120,000	$ 290,713	$ 365,903	$ 365,903	$ 365,903	$ 290,713	$ 20,000	$ 1,819,133
82	Less Capacity Credit		(11,346)	(28,872)	(36,340)	(36,340)	(36,340)	(28,872)	(1,986)	(180,095)
83	Net Peaking Supply Demand Costs		$ 108,654	$ 261,841	$ 329,563	$ 329,563	$ 329,563	$ 261,841	$ 18,014	$ 1,639,038
84										
85	Storage:									
86	Dominion - Demand	Sch.5A, ln 46								
87	Dominion - Storage	Sch.5A, ln 47								
88	Honeoye - Demand	Sch.5A, ln 48								
89	National Fuel - Demand	Sch.5A, ln 49								
90	National Fuel - Capacity	Sch.5A, ln 50								
91	Tenn Gas Pipeline - Demand	Sch.5A, ln 51								
92	Tenn Gas Pipeline - Capacity	Sch.5A, ln 52								
93	Subtotal Storage Demand		$ 648,593	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 1,297,186
94	Less Capacity Credit		(61,325)	(10,736)	(10,736)	(10,736)	(10,736)	(10,736)	(10,736)	(125,740)
95	Net Storage Demand Costs		$ 587,268	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 1,171,446
96										
97	Total Demand Charges	lns 54 + 72 + 81 + 93	$ 1,739,204	$ 1,135,841	$ 1,211,058	$ 1,211,058	$ 1,210,976	$ 1,135,868	$ 865,128	$ 8,509,131
98	Total Capacity Credit	lns 55 + 73 + 82 + 94	(164,443)	(112,806)	(120,276)	(120,276)	(120,268)	(112,809)	(85,920)	(836,798)
99	Net Demand Charges		$ 1,574,761	$ 1,023,035	$ 1,090,781	$ 1,090,781	$ 1,090,708	$ 1,023,059	$ 779,208	$ 7,672,333
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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line	Description	Reference	Peak Costs May 08 - Oct 08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Period Nov - Apr
6										
7	For Month of:									
102	**B. Commodity Costs**									
103	Pipeline:									
104	Dawn Supply	Sch. 6, ln 12								
105	Niagara Supply	Sch. 6, ln 13								
106	TGP Supply (Direct)	Sch. 6, ln 14								
107	TGP Zone 6 Purchases	Sch. 6, ln 15								
108	Dracut Winter Supply	Sch. 6, ln 16								
109	City Gate Delivered Supply	Sch. 6, ln 17								
110	LNG Truck	Sch. 6, ln 18								
111	Propane Truck	Sch. 6, ln 19								
112	PNGTS	Sch. 6, ln 20								
113	Granite Ridge	Sch. 6, ln 21								
114	Subtotal Pipeline Commodity Costs		$ -	$ 10,175,002	$ 16,613,123	$ 18,568,128	$ 15,623,711	$ 9,139,468	$ 8,853,621	$ 78,973,053
115										
116	Storage:									
117	TGP Storage - Withdrawals	Sch. 6, ln 46	$ -	$ 1,475,445	$ 2,368,205	$ 4,293,047	$ 2,851,733	$ 5,352,792	$ -	$ 16,341,221
118										
119	Produced Gas Costs:									
120	LNG Vapor	Sch. 6, ln 49								
121	Propane	Sch. 6, ln 50								
122	Subtotal Produced Gas Costs		$ -	$ 170,252	$ 350,838	$ 1,327,640	$ 591,001	$ 202,800	$ 23,464	$ 2,665,995
123										
124	Less Storage Refills:									
125	LNG Truck	Sch. 6, ln 36								
126	Propane	Sch. 6, ln 37								
127	TGP Storage Refill	Sch. 6, ln 38								
128	Storage Refill (Trans.)	Sch. 6, ln 39								
129	Subtotal Storage Refill		$ -	$ (937,737)	$ (218,076)	$ (1,488,501)	$ (285,371)	$ (208,802)	$ (415,185)	$ (3,553,671)
130										
131	Total Supply Commodity Costs		$ -	$ 10,882,963	$ 19,114,090	$ 22,700,314	$ 18,781,073	$ 14,486,258	$ 8,461,900	$ 94,426,598
132										
133	**C. Supply Volumetric Transportation Costs:**									
134	Dawn Supply	Sch. 6, ln 26								
135	Niagara Supply	Sch. 6, ln 27								
136	TGP Supply (Direct)	Sch. 6, ln 28								
137	TGP Zone 6 Purchases	Sch. 6, ln 29								
138	Dracut Winter Supply	Sch. 6, ln 30								
139	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 586,887	$ 670,156	$ 714,643	$ 633,225	$ 624,375	$ 522,466	$ 3,751,752
140										
141	TGP Storage - Withdrawals	Sch. 6, ln 31	$ -	$ 48,541	$ 77,763	$ 140,967	$ 93,640	$ 175,765	$ -	$ 536,676
142										
143	Total Supply Volumetric Trans. Costs		$ -	$ 635,428	$ 747,919	$ 855,610	$ 726,865	$ 800,141	$ 522,466	$ 4,288,429
144										
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 11,518,390	$ 19,862,009	$ 23,555,924	$ 19,507,938	$ 15,286,399	$ 8,984,366	$ 98,715,027
146										
147										

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Line	Description	Reference	Peak Costs May 08 - Oct 08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Period Nov - Apr
5										
6										
7	For Month of:									
148	**D. Supply and Demand Costs by Source**									
149										
150	Purchased Gas Demand Costs									
151	Pipeline Gas Demand Costs	lns 54 + 72	$ 970,611	$ 737,029	$ 737,056	$ 737,056	$ 736,975	$ 737,056	$ 737,029	$ 5,392,812
152	Peaking Gas Demand Costs	ln 81	120,000	290,713	365,903	365,903	365,903	290,713	20,000	1,819,133
153	Subtotal Purchased Gas Demand Costs		$ 1,090,611	$ 1,027,742	$ 1,102,959	$ 1,102,959	$ 1,102,877	$ 1,027,769	$ 757,029	$ 7,211,945
154	Less Capacity Credit	lns 55 + 73 + 82	(103,118)	(102,070)	(109,540)	(109,540)	(109,532)	(102,073)	(75,184)	(711,058)
155	Net Purchased Gas Demand Costs		$ 987,493	$ 925,672	$ 993,418	$ 993,418	$ 993,345	$ 925,696	$ 681,845	$ 6,500,887
156										
157	Storage Gas Demand Costs									
158	Storage Demand	ln 93	$ 648,593	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 1,297,186
159	Less Capacity Credit	ln 94	(61,325)	(10,736)	(10,736)	(10,736)	(10,736)	(10,736)	(10,736)	(125,740)
160	Net Storage Demand Costs		$ 587,268	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 1,171,446
161										
162	**Total Demand Costs**	lns 155 + 160	$ 1,574,761	$ 1,023,035	$ 1,090,781	$ 1,090,781	$ 1,090,708	$ 1,023,059	$ 779,208	$ 7,672,333
163										
164	Purchased Gas Supply									
165	Commodity Costs	ln 114	$ -	$ 10,175,002	$ 16,613,123	$ 18,568,128	$ 15,623,711	$ 9,139,468	$ 8,853,621	$ 78,973,053
166	Less Storage Inj.(TGP Storage)	ln 127								
167	Less Storage Transportation	ln 128								
168	Less LNG Truck	ln 125								
169	Less Propane Truck	ln 126								
170	Plus Transportation Costs	ln 139								
171	Subtotal Purchased Gas Supply		$ -	$ 9,824,152	$ 17,065,204	$ 17,794,270	$ 15,971,565	$ 9,555,042	$ 8,960,902	$ 79,171,134
172										
173	Storage Commodity Costs									
174	Commodity Costs	ln 117	$ -	$ 1,475,445	$ 2,368,205	$ 4,293,047	$ 2,851,733	$ 5,352,792	$ -	$ 16,341,221
175	Transportation Costs	ln 141	-	48,541	77,763	140,967	93,640	175,765	-	536,676
176	Subtotal Storage Commodity Costs		$ -	$ 1,523,986	$ 2,445,968	$ 4,434,014	$ 2,945,373	$ 5,528,557	$ -	$ 16,877,897
177										
178	Produced Gas Commodity Costs	ln 122	$ -	$ 170,252	$ 350,838	$ 1,327,640	$ 591,001	$ 202,800	$ 23,464	$ 2,665,995
179										
180	**SubTotal Commodity Costs**	lns 171 + 176 + 178	$ -	$ 11,518,390	$ 19,862,009	$ 23,555,924	$ 19,507,938	$ 15,286,399	$ 8,984,366	$ 98,715,027
181										
182	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ 408,036	$ 580,117	$ 666,700	$ 578,533	$ 407,429	$ (115,850)	$ 2,524,964
183										
184	**Total Commodity Costs**	lns 180 + 182	$ -	$ 11,926,426	$ 20,442,125	$ 24,222,624	$ 20,086,471	$ 15,693,827	$ 8,868,516	$ 101,239,991
185										
182	**Total Demand Costs**	ln 99	$ 1,574,761	$ 1,023,035	$ 1,090,781	$ 1,090,781	$ 1,090,708	$ 1,023,059	$ 779,208	$ 7,672,333
183	**Total Supply Costs**	ln 184	-	11,926,426	20,442,125	24,222,624	20,086,471	15,693,827	8,868,516	101,239,991
184										
185	**Total Direct Gas Costs**	lns 182 + 183	$ 1,574,761	$ 12,949,461	$ 21,532,907	$ 25,313,406	$ 21,177,179	$ 16,716,887	$ 9,647,724	$ 108,912,325

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Contracts Ranked on a per Unit Cost Basis

Supplier (a)	Contract (b)	Contract Type (c)	Contract Unit (d)	Unit Dth (MDQ/ACQ) (e)	Peak Period Cost per Unit Dth (f)
Demand Costs					
Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
Tenn Gas Pipeline - Cap. Reservations	FS-MA	Storage	ACQ	1,560,391	
National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
Niagra Supply		Supply	MDQ	3,199	
Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
Granite Ridge Demand		Peaking	MDQ	15,000	
Dominion - Demand	GSS 300076	Storage	MDQ	934	
National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
National Fuel	FST 2358	Transportation	MDQ	6,098	
Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
ANE (TransCanada via Union to Iroquois)	Union Dawn to Iroquois	Transportation	MDQ	4,047	
Tenn Gas Pipeline	33371	Transportation	MDQ	4,000	
Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
DOMAC Liquid FLS-164		Peaking	MDQ	6,300	
Supply Costs - Commodity					
LNG Vapor (Storage)		Produced	Dkt	141,050	
City Gate Delivered Supply		Pipeline	Dkt	1,056,341	
LNG Truck		Pipeline	Dkt	135,105	
TGP Supply (Direct)		Pipeline	Dkt	3,453,464	
TGP Zone 6 Purchases		Pipeline	Dkt	105,292	
Granite Ridge		Pipeline	Dkt	-	
Dawn Supply		Pipeline	Dkt	643,010	
Niagara Supply		Pipeline	Dkt	509,076	
PNGTS		Pipeline	Dkt	20,986	
Dracut Winter Supply		Pipeline	Dkt	1,736,189	
TGP Storage		Storage	Dkt	1,906,512	
Propane		Produced	Dkt	85,026	
Propane Truck		Pipeline	Dkt	56,294	
Supply Costs - Volumetric Transportation					
TGP Zone 6 Purchases		Pipeline	Dkt	105,292	
Dracut Winter Supply		Pipeline	Dkt	1,736,189	
Niagara Supply		Pipeline	Dkt	509,076	
TGP Storage - Withdrawals		Pipeline	Dkt	1,906,512	
Dawn Supply		Pipeline	Dkt	643,010	
TGP Supply (Direct)		Pipeline	Dkt	3,453,464	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			Prior Period Balance Apr-08 Ending Bal Plus May Billings	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Peak Period Total
8		Days in Month		31	30	31	31	30	31	30	31	31	28	31	30	31	
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Accunt 175.20 COG (Over)/Under Balance - Interest Calculation**																
11																	
12	**Beginning Balance**	Account 175.20 1/	**$ 7,915,782**	$ 2,883,321	$ 3,146,818	$ 2,798,435	$ 2,867,684	$ 2,975,031	$ 3,228,921	$ 3,479,454	$ 12,146,981	$ 15,197,455	$ 17,710,270	$ 15,265,447	$ 11,561,657	$ 5,715,948	$ 7,915,782
13	Forecast Direct Gas Costs	Schedule 5A		262,460	262,460	262,460	262,460	262,460	262,460	12,949,461	21,532,907	25,313,406	21,177,179	16,716,887	9,647,724	-	108,912,324
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	368,840	368,840	368,840	368,840	368,840	368,840		2,213,041
15	Projected Revenues w/o Int.	ln 47 * 49		-	-	-	-	-	-	(4,760,630)	(18,928,568)	(23,193,150)	(24,031,229)	(20,771,319)	(15,904,702)	(5,313,268)	(112,902,866)
16	Prior Period Adjustment				-					-							-
17	Add Net Adjustments	Schedule 4		(22,402)	(623,035)	(205,216)	(167,493)	(21,292)	(26,140)	77,813	19,357	(46,005)	(22,734)	(75,038)	7,000	-	(1,105,186)
18	Gas Cost Billed	Account 175.20 2/	(5,032,461)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,032,461)
19	Monthly (Over)/Under Recovery		$ 2,883,321	$ 3,123,379	$ 2,786,244	$ 2,855,679	$ 2,962,651	$ 3,216,199	$ 3,465,241	$ 12,114,938	$ 15,139,518	$ 17,640,545	$ 15,202,327	$ 11,504,816	$ 5,680,519	$ 402,680	$ 634
20	Average Monthly Balance	(ln 12 + 19)/2		$ 5,519,580	$ 2,966,531	$ 2,827,057	$ 2,915,168	$ 3,095,615	$ 3,347,081	$ 7,797,196	$ 13,643,250	$ 16,419,000	$ 16,456,298	$ 13,385,132	$ 8,621,088	$ 3,059,314	
21																	
22	Interest Rate	Prime Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%		
23																	
24	Interest Applied	ln 20 * ln 22 / 365 * Days of Month		$ 23,439	$ 12,191	$ 12,005	$ 12,379	$ 12,722	$ 14,214	$ 32,043	$ 57,937	$ 69,725	$ 63,120	$ 56,841	$ 35,429	$ -	$ 402,046
25																	
26	**(Over)/Under Balance**	ln 19 + ln 24	$ 2,883,321	$ 3,146,818	$ 2,798,435	$ 2,867,684	$ 2,975,031	$ 3,228,921	$ 3,479,454	$ 12,146,981	$ 15,197,455	$ 17,710,270	$ 15,265,447	$ 11,561,657	$ 5,715,948	$ 402,680	402,680
27																	
28																	
29	**Calculation of COG with Interest**																
30																	
31	**Beginning Balance**	ln 12	$ 7,915,782	$ 2,883,321	$ 3,146,818	$ 2,798,435	$ 2,867,684	$ 2,975,031	$ 3,228,921	$ 3,479,454	$ 12,130,246	$ 15,113,964	$ 17,544,713	$ 15,014,576	$ 11,236,531	$ 5,333,428	$ 7,915,782
32	Forecast Direct Gas Costs	ln 13		262,460	262,460	262,460	262,460	262,460	262,460	12,949,461	21,532,907	25,313,406	21,177,179	16,716,887	9,647,724	-	108,912,324
33	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	368,840	368,840	368,840	368,840	368,840	368,840	-	2,213,041
34	Projected Revenues with int.	ln 47 * ln 51		-	-	-	-	-	-	(4,777,396)	(18,995,234)	(23,274,836)	(24,115,866)	(20,844,475)	(15,960,718)	(5,331,981)	(113,300,507)
35	Add Net Adjustments	ln 17		(22,402)	(623,035)	(205,216)	(167,493)	(21,292)	(26,140)	77,813	19,357	(46,005)	(22,734)	(75,038)	7,000	-	(1,105,186)
36	Gas Cost Billed	ln 18	(5,032,461)		-	-	-	-	-	-	-	-	-	-	-	-	(5,032,461)
37	Add Interest	ln 24		-	-	-	-	-	-	32,043	57,937	69,725	63,120	56,841	35,429	-	315,095
38	**(Over)/Under Balance**		$ 2,883,321	$ 3,123,379	$ 2,786,244	$ 2,855,679	$ 2,962,651	$ 3,216,199	$ 3,465,241	$ 12,130,215	$ 15,114,053	$ 17,545,093	$ 15,015,253	$ 11,237,631	$ 5,334,806	$ 1,447	$ (81,911)
39																	
40	Average Monthly Balance			$ 5,519,580	$ 2,966,531	$ 2,827,057	$ 2,915,168	$ 3,095,615	$ 3,347,081	$ 7,804,835	$ 13,622,150	$ 16,329,528	$ 16,279,983	$ 13,126,104	$ 8,285,669	$ 2,667,437	
41																	
42	Interest Applied	ln 22 * ln 40 / 365 * Days of Month		23,439	12,191	12,005	12,379	12,722	14,214	32,075	57,847	69,345	62,444	55,741	34,051	-	398,453
43																	
44	**(Over)/Under Balance**	-ln 37 +ln 38 + ln 42	$ 2,883,321	$ 3,146,818	$ 2,798,435	$ 2,867,684	$ 2,975,031	$ 3,228,921	$ 3,479,454	$ 12,130,246	$ 15,113,964	$ 17,544,713	$ 15,014,576	$ 11,236,531	$ 5,333,428	$ 1,447	1,447
45																	
46																	
47	Forecast Billing Therm Sales	Sch. 10B, ln 24 Nov - May								3,810,638	15,151,339	18,564,916	19,235,755	16,626,366	12,730,891	4,252,996	90,372,901
48																	
49	COB w/o Interest	Sch. 3, pg. 4, ln 186 col. (c)								$1.2493	$1.2493	$1.2493	$1.2493	$1.2493	$1.2493	$1.2493	
50																	
51	COG With Interest	Sch. 3, pg. 4, ln 186 col. (d)								$1.2537	$1.2537	$1.2537	$1.2537	$1.2537	$1.2537	$1.2537	

55 1/ Beginning Balance for Acct 175.20. See Tab 18, Schedule 1, page 1, line 30, April 2008 column.
56 2/ Gas Cost Billed Acct 175.20. See Tab 18, Schedule 1, page 1, line 14, May 2008 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

60			Prior Period Balance														
61			Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Peak Period
62		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
63	(a)	(b)	Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
65	**Accunt 142.20 Working Capital (Over)/Under Balance - Interest Calculation**																
67	**Beginning Balance**	Account 142.20 1/	**$ (261,076)**	$ (305,654)	$ (305,161)	$ (304,719)	$ (304,317)	$ (303,912)	$ (303,465)	$ (303,057)	$ (237,408)	$ (166,042)	$ (84,988)	$ (33,259)	$ 1,342	$ 7,572	$ (261,076)
69	Forecast Working Capital	ln 32 * 0.00645		1,693	1,693	1,693	1,693	1,693	1,693	83,524	138,887	163,271	136,593	107,824	62,228	-	702,484
71	Projected Revenues w/o Int.	ln 104 * ln 106		-	-	-	-	-	-	(16,767)	(66,666)	(81,686)	(84,637)	(73,156)	(56,016)	(18,713)	(397,641)
73	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Working Capital Billed	Account 142.20 2/	(44,579)														(44,579)
77	Monthly (Over)/Under Recovery		$ (305,654)	$ (303,962)	$ (303,468)	$ (303,026)	$ (302,624)	$ (302,220)	$ (301,772)	$ (236,300)	$ (165,187)	$ (84,456)	$ (33,032)	$ 1,409	$ 7,553	$ (11,141)	$ (811)
79	Average Monthly Balance	(ln 67 + ln 77)/2		$ (282,519)	$ (304,315)	$ (303,873)	$ (303,470)	$ (303,066)	$ (302,619)	$ (269,679)	$ (201,298)	$ (125,249)	$ (59,010)	$ (15,925)	$ 4,448	$ (1,785)	
81	Interest Rate	Prime Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%		
83	Interest Applied	ln 79 * ln 81 / 365 * Days of Month		$ (1,200)	$ (1,251)	$ (1,290)	$ (1,289)	$ (1,245)	$ (1,285)	$ (1,108)	$ (855)	$ (532)	$ (226)	$ (68)	$ 18	$ -	$ (10,331)
85	**(Over)/Under Balance**	ln 77 + ln 83	$ (305,654)	$ (305,161)	$ (304,719)	$ (304,317)	$ (303,912)	$ (303,465)	$ (303,057)	$ (237,408)	$ (166,042)	$ (84,988)	$ (33,259)	$ 1,342	$ 7,572	$ (11,141)	(11,141)
88	**Calculation of Working Capital with Interest**																
90	**Beginning Balance**	ln 67	$ (261,076)	$ (305,654)	$ (305,161)	$ (304,719)	$ (304,317)	$ (303,912)	$ (303,465)	$ (303,057)	$ (237,029)	$ (164,144)	$ (81,223)	$ (27,552)	$ 8,738	$ 16,275	$ (261,076)
91	Forecast Working Capital	ln 69		1,693	1,693	1,693	1,693	1,693	1,693	83,524	138,887	163,271	136,593	107,824	62,228	-	702,484
92	Projected Rev. with interest	ln 104 * ln 108		-	-	-	-	-	-	(16,386)	(65,151)	(79,829)	(82,714)	(71,493)	(54,743)	(18,288)	(388,603)
93	Add Net Adjustments	ln 73		-	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Working Capital Billed	ln 75	(44,579)	-	-	-	-	-	-								(44,579)
95	Add Interest	ln 83		-	-	-	-	-	-	(1,108)	(855)	(532)	(226)	(68)	18	-	(2,771)
96	Monthly (Over)/Under Recovery		$ (305,654)	$ (303,962)	$ (303,468)	$ (303,026)	$ (302,624)	$ (302,220)	$ (301,772)	$ (237,027)	$ (164,147)	$ (81,234)	$ (27,570)	$ 8,711	$ 16,241	$ (2,013)	$ 5,456
98	Average Monthly Balance			$ (282,519)	$ (304,315)	$ (303,873)	$ (303,470)	$ (303,066)	$ (302,619)	$ (270,042)	$ (200,588)	$ (122,689)	$ (54,396)	$ (9,421)	$ 12,490	$ 7,131	
100	Interest Applied	ln 81 * ln 98 / 365 * Days of Month		(1,200)	(1,251)	(1,290)	(1,289)	(1,245)	(1,285)	(1,110)	(852)	(521)	(209)	(40)	51	-	$ (10,240)
102	**(Over)/Under Balance**	-ln 95 +ln 96 + ln 100	$ (305,654)	$ (305,161)	$ (304,719)	$ (304,317)	$ (303,912)	$ (303,465)	$ (303,057)	$ (237,029)	$ (164,144)	$ (81,223)	$ (27,552)	$ 8,738	$ 16,275	$ (2,013)	$ (2,013)
104	Forecast Term Sales	ln 47								3,810,638	15,151,339	18,564,916	19,235,755	16,626,366	12,730,891	4,252,996	90,372,901
106	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 203 col. (c)								$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	
108	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 203 col. (d)								$0.0043	$0.0043	$0.0043	$0.0043	$0.0043	$0.0043	$0.0043	

109 1/ Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 15, April 2008 column.
110 2/ Working Capital Billed Acct 142.20. See Tab 18, Schedule 5, page 1, line 3, May 2008 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			Prior Period Balance														
112			Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	DemandPeriod
113		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
114	(a)	(b)	Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
115																	
116	**Accunt 175.52 Bad Debt (Over)/Under Balance - Interest Calculation**																
117																	
118	Forecast Direct Gas Costs	ln 32		$ 262,460	$ 262,460	$ 262,460	$ 262,460	$ 262,460	$ 262,460	$12,949,461	$ 21,532,907	$ 25,313,406	$ 21,177,179	$ 16,716,887	$ 9,647,724	$ -	108,912,324
119	Forecast Working Capital	ln 90		1,693	1,693	1,693	1,693	1,693	1,693	(222,130)	138,887	163,271	136,593	107,824	62,228		396,830
120	Prior Period Balance	ln 38								480,554	480,554	480,554	480,554	480,554	480,554		2,883,321
121	Total Forecast Direct Gas Costs & Working Capital			264,153	264,153	264,153	264,153	264,153	264,153	13,207,884	22,152,348	25,957,231	21,794,326	17,305,264	10,190,505	-	109,309,154
122																	
123	**Beginning Balance**	Account 175.52 1/	**$ (1,289,664)**	$ (1,409,904)	$ (1,411,003)	$ (1,412,170)	$ (1,413,534)	$ (1,414,904)	$ (1,416,087)	$ (1,417,468)	$ (1,214,973)	$ (924,263)	$ (586,458)	$ (324,138)	$ (123,666)	$ (23,292)	$ (1,289,664)
124																	
125	Forecast Bad Debt	ln 121 * 0.0175		4,623	4,623	4,623	4,623	4,623	4,623	231,138	387,666	454,252	381,401	302,842	178,334		1,963,368
126																	
127	Projected Revenues w/o int	ln 160 * ln 162		-	-	-	-	-	-	(23,245)	(92,423)	(113,246)	(117,338)	(101,421)	(77,658)	(12,972)	(538,303)
128																	
129	Bad Debt Billed	Account 175.52 2/	(120,240)		-	-	-	-	-		-	-	-	-	-	-	(120,240)
130																	
131	Add Net Adjustments			-	-	-	-	-	-		-	-	-	-	-	-	-
132																	
133	Monthly (Over)/Under Recovery		$ (1,409,904)	$ (1,405,281)	$ (1,406,381)	$ (1,407,547)	$ (1,408,912)	$ (1,410,282)	$ (1,411,464)	$ (1,209,575)	$ (919,730)	$ (583,257)	$ (322,395)	$ (122,717)	$ (22,990)	$ (36,263)	$ 15,161
134																	
135	Average Monthly Balance	(ln 123 + ln 133)/2		$ (1,347,472)	$ (1,408,692)	$ (1,409,858)	$ (1,411,223)	$ (1,412,593)	$ (1,413,776)	$ (1,313,521)	$ (1,067,351)	$ (753,760)	$ (454,427)	$ (223,428)	$ (73,328)	$ (29,778)	
136																	
137	Interest Rate	Prime Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%		
138																	
139	Interest Applied	ln 135 * ln 137 / 365 * Days of Month		$ (5,722)	$ (5,789)	$ (5,987)	$ (5,993)	$ (5,805)	$ (6,004)	$ (5,398)	$ (4,533)	$ (3,201)	$ (1,743)	$ (949)	$ (301)		$ (51,425)
140																	
141	**(Over)/Under Balance**	ln 133 + ln 139	$ (1,409,904)	$ (1,411,003)	$ (1,412,170)	$ (1,413,534)	$ (1,414,904)	$ (1,416,087)	$ (1,417,468)	$ (1,214,973)	$ (924,263)	$ (586,458)	$ (324,138)	$ (123,666)	$ (23,292)	$ (36,263)	(36,263)
142																	
143																	
144	**Calculation of Bad Debt with Interest**																
145																	
146	**Beginning Balance**	ln 123	$ (1,289,664)	$ (1,409,904)	$ (1,411,003)	$ (1,412,170)	$ (1,413,534)	$ (1,414,904)	$ (1,416,087)	$ (1,417,468)	$ (1,213,075)	$ (914,774)	$ (567,687)	$ (295,750)	$ (86,964)	$ 19,776	$ (1,289,664)
147	Forecast Bad Debt	ln 125		4,623	4,623	4,623	4,623	4,623	4,623	231,138	387,666	454,252	381,401	302,842	178,334	-	1,963,368
148	Projected Revenues with int.	ln 160 * ln 164		-	-	-	-	-	-	(21,340)	(84,847)	(103,964)	(107,720)	(93,108)	(71,293)	(23,817)	(506,088)
149	Bad Debt Billed	ln 129	(120,240)		-	-	-	-	-	-	-	-	-	-	-	-	(120,240)
150	Add Interest	ln 139		-	-	-	-	-	-	(5,398)	(4,533)	(3,201)	(1,743)	(949)	(301)	-	(16,125)
151	Add Net Adjustments	ln 131								-	-	-	-	-	-	-	0
152	Monthly (Over)/Under Recovery		$ (1,409,904)	$ (1,405,281)	$ (1,406,381)	$ (1,407,547)	$ (1,408,912)	$ (1,410,282)	$ (1,411,464)	$ (1,213,068)	$ (914,789)	$ (567,687)	$ (295,750)	$ (86,964)	$ 19,776	$ (4,041)	$ 31,252
153																	
154	Average Monthly Balance			$ (1,347,472)	$ (1,408,692)	$ (1,409,858)	$ (1,411,223)	$ (1,412,593)	$ (1,413,776)	$ (1,315,268)	$ (1,063,932)	$ (741,231)	$ (431,718)	$ (191,357)	$ (33,594)	$ 7,867	
155																	
156	Interest Applied	ln 137 * ln 154 / 365 * Days of Month		(5,722)	(5,789)	(5,987)	(5,993)	(5,805)	(6,004)	(5,405)	(4,518)	(3,201)	(1,743)	(949)	(301)	-	$ (51,417)
157																	
158	**(Over)/Under Balance**	-ln 150 +ln 152 + ln 156	$ (1,409,904)	$ (1,411,003)	$ (1,412,170)	$ (1,413,534)	$ (1,414,904)	$ (1,416,087)	$ (1,417,468)	$ (1,213,075)	$ (914,774)	$ (567,687)	$ (295,750)	$ (86,964)	$ 19,776	$ (4,041)	$ (4,041)
159																	
160	Forecast Term Sales	ln 47								3,810,638	15,151,339	18,564,916	19,235,755	16,626,366	12,730,891	4,252,996	90,372,901
161																	
162	COG Rate Without Interest	Sch. 3, pg. 4, ln 220 col. (c)								$0.0061	$0.0061	$0.0061	$0.0061	$0.0061	$0.0061	$0.0061	
163																	
164	COG With Interest	Sch. 3, pg. 4, ln 220 col. (d)								$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
165	1/ Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 19, April 2008 column.																
166	2/ Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 9, May 2008 column.																
167																	
168	**Total Interest**	lns 42 + 100 + 156	$ -	$ 16,517	$ 5,151	$ 4,728	$ 5,098	$ 5,671	$ 6,925	$ 25,560	$ 52,478	$ 65,623	$ 60,492	$ 54,752	$ 33,801	$ -	$ 336,795

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln				
169				
			COG Rate Without Interest	COG Rate With Interest
170	**Calculation of COG**			
171	(a)	(b)	(c)	(d)
172	(Over)Under Recovery Balance	ln 12, col. (q)	$ 7,915,782	$ 7,915,782
173				
174	Unadjusted Forecast of Gas Costs	ln 13, col. (q)	108,912,324	108,912,324
175				
176	Production & Storage and Misc Overhe	ln 14, col. (q)	2,213,041	2,213,041
177				
178	Adjustments	ln 17, col. (q)	(6,137,646)	(6,137,646)
179				
180	Interest Nov -Apr	ln 24, col. (q)	-	$ 398,453
181				
182	Total Gas To Be Recovered		$ 112,903,500	$ 113,301,953
183				
184	Forecast Gas Sales (May - Oct)	ln 47, col. (q)	90,372,901	90,372,901
185				
186	Preliminary COG Rate	ln. 227 / ln. 229	$1.2493	$1.2537
187				
188				
			Working Capital Rate without interest	Working Capital Rate with Interest
189	**Calculation of Working Capital Rate**			
190	(a)	(b)	(c)	(d)
191	(Over)Under Recovery Balance	ln 67, col. (q)	$ (261,076)	$ (261,076)
192				
193	Unadjusted Working Capital Forecast	ln 69, col. (q)	702,484	702,484
194				
195	Adjustments without interest	ln 73, col. (q)	(44,579)	(44,579)
196				
197	Interest (May - Oct)	ln 83, col. (q)	-	$ (10,240)
198				
199	Total Gas To Be Recovered		$ 396,830	$ 386,590
200				
201	Forecast Gas Sales	ln 47, col. (q)	90,372,901	90,372,901
202				
203	Preliminary Working Capital COG Rate		$0.0044	$0.0043
204				
205				
			Bad Debt Rate without Interest	Bad Debt Rate with interest
206	**Calculation of Bad Debt Rate**			
207	(a)	(b)	(c)	
208	(Over)Under Recovery Balance	ln 123, col. (q)	$ (1,289,664)	$ (1,289,664)
209				
210	Unadjusted Bad Debt Forecast	ln 125, col. (q)	1,963,368	1,963,368
211				
212	Adjustments without interest	ln 131, col. (q)	(120,240)	(120,240)
213				
214	Interest (May - Oct)	ln 139, col. (q)	-	$ (51,417)
215				
216	Total Gas To Be Recovered		$ 553,464	$ 502,047
217				
218	Forecast Gas Sales (May - Oct)	ln 47, col. (q)	90,372,901	90,372,901
219				
220	Preliminary Bad Debt COG Rate		$0.0061	$0.0056

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Adjustments to Gas Costs

Adjustments (a)	Prior Period Adjustments (b)	Refunds from Suppliers (c)	Broker Revenue (d)	Inventory Finance Charges (e)	Transportation CGA Revenues (Schedule 17) (f)	Interruptible Sales Margin (g)	Off System Sales Margin (h)	Capacity Release (i)	COG Hedging Costs (j)	Fixed Price Option Administrative Costs (k)	Total Adjustments (m)
May-08	$ -	$ -	$ (44,165)	$ 57,434	$ -				$ -	$ -	$ (22,402)
Jun-08	-	-	(621,305)	54,766	-				-	-	(623,035)
Jul-08	-	-	(112,422)	46,385	-				-	-	(205,216)
Aug-08 1/	-	-	(18,167)	(48,305)	-				-	-	(167,493)
Sep-08 1/	-	-	(6,485)	38,188	-				-	-	(21,292)
Oct-08 1/	-	-	(30,637)	28,851	-				-	-	(26,140)
Nov-08 1/	-	-	(50,697)	93,290	(568)				-	36,312	77,813
Dec-08 1/	-	-	(65,305)	85,415	(752)				-	-	19,357
Jan-09 1/	-	-	(116,307)	71,237	(935)				-	-	(46,005)
Feb-09 1/	-	-	(73,857)	52,099	(976)				-	-	(22,734)
Mar-09 1/	-	-	(101,813)	27,697	(922)				-	-	(75,038)
Apr-09 1/	-	-	(8,539)	19,199	(849)				-	-	7,000
Subtotal May 08 - Oct 08	$ -	$ -	$ (833,181)	$ 177,319	$ -	$ (2,245)	$ (60,510)	$ (346,961)	$ -	$ -	$ (1,065,578)
Subtotal Nov 08 - Apr 09	$ -	$ -	$ (416,518)	$ 348,937	$ (5,004)	$ -	$ (1,428)	$ (1,907)	$ -	$ 36,312	$ (39,608)
Total Peak Period	$ -	$ -	$ (1,249,699)	$ 526,256	$ (5,004)	$ (2,245)	$ (61,938)	$ (348,868)	$ -	$ 36,312	$ (1,105,186)

1/ Estimate is based on prior years actual. Exception: Transportation Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 08 - Apr 09 calculated on Schedule 16.

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Demand Costs

Ln	(a)	Peak (b)	Reference (c)	Peak Costs May 08 -Oct 08 (d)	Nov-08 (e)	Dec-08 (f)	Jan-09 (g)	Feb-09 (h)	Mar-09 (i)	Apr-09 (j)	Peak May -Apr Total (k)
11	**Supply**										
12	Niagra Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days								
13	Subtotal Supply Demand & Reservation Charges										
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	$ -	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 160,191
17	Tenn Gas Pipeline 33371		Sch 5B, ln 13 * Sch 5C ln 16 x days	-	42,440	42,440	42,440	42,440	42,440	42,440	254,640
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 18 x days	-	15,391	15,391	15,391	15,391	15,391	15,391	92,349
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 20 x days	-	116,711	116,711	116,711	116,711	116,711	116,711	700,264
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 22 x days	-	220,599	220,599	220,599	220,599	220,599	220,599	1,323,595
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 24 x days	-	22,447	22,447	22,447	22,447	22,447	22,447	134,681
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 26 x days	-	63,200	63,200	63,200	63,200	63,200	63,200	379,200
23	Portland Natural Gas Trans Service		Sch 5B, ln 19 * Sch 5C ln 28 x days	-	27,402	27,402	27,402	27,402	27,402	27,402	164,410
24	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 20 * Sch 5C ln 44 x days	-	39,557	39,557	39,557	39,557	39,557	39,557	237,340
25	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 21 * Sch 5C ln 30 x days	$ 539,465	89,911	89,911	89,911	89,911	89,911	89,911	1,078,930
26	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 22 * Sch 5C ln 32 x days	250,278	41,713	41,713	41,713	41,713	41,713	41,713	500,556
27	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 23 * Sch 5C ln 34 x days	57,888	9,648	9,648	9,648	9,648	9,648	9,648	115,776
28	National Fuel FST 2358	peak	Sch 5B, ln 24 * Sch 5C ln 36 x days	122,980	20,497	20,497	20,497	20,497	20,497	20,497	245,959
30	Subtotal Pipeline Demand Charges			$ 970,611	$ 736,213	$ 736,213	$ 736,213	$ 736,213	$ 736,213	$ 736,213	$ 5,387,890
32	**Peaking Supply**										
33	Granite Ridge Demand	peak	Sch 5B, ln 27 * Sch 5C ln 47 x days								
34	DOMAC Liquid FLS-164	peak	Per 06-10 Contract								
35	DOMAC Demand FLS-160	peak	Per 07-08 Contract								
36	Transgas Trucking	peak	Per 07-08 Contract (negotiating as of 9/1)								
37	Subtotal Peaking Demand Chargs			$ 120,000	$ 290,713	$ 365,903	$ 365,903	$ 365,903	$ 290,713	$ 20,000	$ 1,819,133
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 30 + ln 37	$ 1,090,611	$ 1,027,742	$ 1,102,959	$ 1,102,959	$ 1,102,877	$ 1,027,769	$ 757,029	$ 7,211,945
41	Less Transportation Capacity Credit			$ (103,118)	$ (102,070)	$ (109,540)	$ (109,540)	$ (109,532)	$ (102,073)	$ (75,184)	$ (711,058)
43	**Total Supply, Pipeline & Peaking Demand**			$ 987,493	$ 925,672	$ 993,418	$ 993,418	$ 993,345	$ 925,696	$ 681,845	$ 6,500,887
45	**Storage**										
46	Dominion - Demand	peak	Sch 5B, ln 31 * Sch 5C ln 51 x days	$ 10,524	$ 1,754	$ 1,754	$ 1,754	$ 1,754	$ 1,754	$ 1,754	$ 21,049
47	Dominion - Storage	peak	Sch 5B, ln 32 * Sch 5C ln 52 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
48	Honeoye - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 55 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
49	National Fuel - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 57 x days	78,869	13,145	13,145	13,145	13,145	13,145	13,145	157,738
50	National Fuel - Capacity	peak	Sch 5B, ln 36 * Sch 5C ln 58 x days	173,871	28,979	28,979	28,979	28,979	28,979	28,979	347,743
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 61 x days	150,724	25,121	25,121	25,121	25,121	25,121	25,121	301,447
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 62 x days	173,203	28,867	28,867	28,867	28,867	28,867	28,867	346,407
54	**Subtotal Storage Demand Costs**			$ 648,593	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 108,099	$ 1,297,186
56	Less Transportation Capacity Credit			$ (61,325)	$ (10,736)	$ (10,736)	$ (10,736)	$ (10,736)	$ (10,736)	$ (10,736)	$ (125,740)
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 587,268	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 97,363	$ 1,171,446
60	**Total Demand Charges**		ln 39 + ln 54	$ 1,739,204	$ 1,135,841	$ 1,211,058	$ 1,211,058	$ 1,210,976	$ 1,135,868	$ 865,128	$ 8,509,131
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (164,443)	$ (112,806)	$ (120,276)	$ (120,276)	$ (120,268)	$ (112,809)	$ (85,920)	$ (836,798)
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,574,761	$ 1,023,035	$ 1,090,781	$ 1,090,781	$ 1,090,708	$ 1,023,059	$ 779,208	$ 7,672,333

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Demand Volumes

		Peak	Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply									
	Niagra Supply			3,199	3,199	3,199	3,199	3,199	3,199
Pipeline									
	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline		33371	4,000	4,000	4,000	4,000	4,000	4,000
	Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
	Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
	Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
	Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
	Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
	ANE (TransCanada via Union to Iroquois)		Union Dawn to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
	National Fuel	peak	FST 2358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking									
	Granite Ridge Demand	peak		15,000	15,000	15,000	15,000	15,000	15,000
	DOMAC Liquid Demand Charge	peak	FLS-XXX	6,300	6,300	6,300	6,300	6,300	0
Storage									
	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
	Honeoye - Capacity	peak	SS-NY	246,240	246,240	246,240	246,240	246,240	246,240
	National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
	National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
	Tenn Gas Pipeline - Demand	peak	FS-MA	21,844	21,844	21,844	21,844	21,844	21,844
	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Demand Rates

				Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov - Apr
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagra Supply										
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$6.5971	30th Rev Sheet No. 4	$0.2199	$0.2128	$0.2128	$0.2356	$0.2128	$0.2199	$0.2190
Tenn Gas Pipeline	33371 Segment 3	$5.0700	41st Rev Sheet No. 26B	$0.1690	$0.1635	$0.1635	$0.1811	$0.1635	$0.1690	$0.1683
Tenn Gas Pipeline	33371 Segment 4	$5.5400	41st Rev Sheet No. 26B	$0.1847	$0.1787	$0.1787	$0.1979	$0.1787	$0.1847	$0.1839
		$10.6100		$0.3537	$0.3423	$0.3423	$0.3789	$0.3423	$0.3537	$0.3522
Tenn Gas Pipeline	2302 Z5-Z6	$4.9300	26th Rev Sheet No. 23	$0.1643	$0.1590	$0.1590	$0.1761	$0.1590	$0.1643	$0.1636
Tenn Gas Pipeline	8587 Z0-Z6	$16.5900	26th Rev Sheet No. 23	$0.5530	$0.5352	$0.5352	$0.5925	$0.5352	$0.5530	$0.5507
Tenn Gas Pipeline	8587 Z1-Z6	$15.1500	26th Rev Sheet No. 23	$0.5050	$0.4887	$0.4887	$0.5411	$0.4887	$0.5050	$0.5029
Tenn Gas Pipeline	8587 Z4-Z6	$5.8900	26th Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
TGP Dracut	42076 FTA Z6-Z6	$3.1600	26th Rev Sheet No. 23	$0.1053	$0.1019	$0.1019	$0.1129	$0.1019	$0.1053	$0.1049
Portland Natural Gas	FT-1999-001	$27.4017	3rd Rev Sheet No. 100	$0.9134	$0.8839	$0.8839	$0.9786	$0.8839	$0.9134	$0.9095
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$5.8900	26th Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$5.8900	26th Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$4.9300	26th Rev Sheet No. 23	$0.1643	$0.1590	$0.1590	$0.1761	$0.1590	$0.1643	$0.1636
National Fuel	FST 2358	$3.3612	117th Rev Sheet No. 9	$0.1120	$0.1084	$0.1084	$0.1200	$0.1084	$0.1120	$0.1116
ANE TransCanada PipeLines Limited		$9.3281	Union Dawn to Iroquois							
Delivery Pressure Demand Charge		0.4957	Union Dawn to Iroquois							
Sub Total Demand Charges		9.8238								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		0.9430	8/18/2008							
Demand Rate/US$		$9.7743		$0.3258	$0.3153	$0.3153	$0.3491	$0.3153	$0.3258	$0.3244
Peaking										
Granite Ridge Demand										
DOMAC Liquid FLS-164										
Storage										
Dominion - Demand	GSS 300076	$1.8780	29th Rev Sheet No. 35	$0.0626	$0.0606	$0.0606	$0.0671	$0.0606	$0.0626	$0.0623
Dominion - Capacity	GSS 300076	$0.0145	29th Rev Sheet No. 35	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8925		$0.0631	$0.0610	$0.0610	$0.0676	$0.0610	$0.0631	$0.0628
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet 5	$0.2140	$0.2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
National Fuel - Demand	FSS-1 2357	$2.1556	15th Rev. Sheet No. 10	$0.0719	$0.0695	$0.0695	$0.0770	$0.0695	$0.0719	$0.0715
National Fuel - Capacity	FSS-1 2357	$0.0432	15th Rev. Sheet No. 10	$0.0014	$0.0014	$0.0014	$0.0015	$0.0014	$0.0014	$0.0014
		$2.1988		$0.0733	$0.0709	$0.0709	$0.0785	$0.0709	$0.0733	$0.0729
Tenn Gas Pipeline	FS-MA	$1.1500	17th Rev Sheet No. 27	$0.0383	$0.0371	$0.0371	$0.0411	$0.0371	$0.0383	$0.0381
Tenn Gas Pipeline - Space	FS-MA	$0.0185	17th Rev Sheet No. 27	$0.0006	$0.0006	$0.0006	$0.0007	$0.0006	$0.0006	$0.0006
		$1.1685		$0.0390	$0.0377	$0.0377	$0.0417	$0.0377	$0.0390	$0.0388

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APPLICABLE TO SETTLING PARTIES PURSUANT TO THE MARCH 29, 2005, STIPULATION
IN DOCKET NOS. RP97-406, RP00-15, RP00-344 and RP00-632
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE SHEET 35A)

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
===	Storage Demand	$1.7984	$0.0678	$0.0195	($0.0094)	$0.0017	-	$1.8780
	Storage Capacity	$0.0145	-	-	-	-	-	$0.0145
	Injection Charge	$0.0154	-	$0.0063	$0.0000	$0.0002	-	$0.0219
	Withdrawal Charge	$0.0154	-	-	$0.0000	$0.0002	$0.0019	$0.0175
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0000	-	-	$0.0046
	Demand Charge Adjustment	$21.5808	$0.8136	$0.2340	($0.1128)	$0.0204	-	$22.5360
	From Customers Balance	$0.6163	$0.0148	$0.0042	($0.0020)	$0.0006	$0.0019	$0.6358
ISS [2]								
======	ISS Capacity	$0.0736	$0.0022	$0.0006	($0.0003)	$0.0001	-	$0.0762
	Injection Charge	$0.0154	-	$0.0063	$0.0000	$0.0002	-	$0.0219
	Withdrawal Charge	$0.0154	-	-	$0.0000	$0.0002	$0.0019	$0.0175
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0148	$0.0042	($0.0020)	$0.0006	$0.0019	$0.6358
	Excess Injection Charge	$0.2245	-	$0.0063	$0.0000	$0.0002	-	$0.2310

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.28% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 2.56%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6183.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.

subject to an allowable variation of not more than one percent above or below the aggregate of said scheduled daily deliveries of said month.

The amount of gas in storage for Buyer's account at any time (exclusive of Buyer's share of cushion gas) shall be Buyer's Gas Storage Balance at that time and shall not exceed Buyer's Maximum Quantity Stored (MQS).

Seller shall be ready at all times to deliver to Buyer, and Buyer shall have the right at all times to receive from Seller, natural gas up to the MDWQ Seller is obligated to deliver to Buyer on that day.

Buyer's MQS, Buyer's MDWQ and Buyer's ADWQ shall be specified in the Gas Storage Agreement providing for service under this Rate Schedule.

3. RATE

Buyer shall pay Seller for each month of the year during the term of the Gas Storage Agreement a Demand Charge which shall be six dollars and forty one point eight seven cents per MMBTU ($6.4187/MMBTU)** multiplied by the ADWQ as provided for in the Gas Storage Agreement.

4. MINIMUM BILL

The Minimum Bill for each month shall consist of the Demand Charge for the ADWQ as defined in Article 3.

5. COMPRESSOR FUEL ALLOWANCE

Buyer will make available without charge to Seller such additional quantities of gas as needed by Seller for

** The Demand Charge Rate set forth in individual service agreements shall be deemed to have been converted to a thermal billing basis utilizing a factor of 1022/MMBTU per 1 MCF as adjusted pursuant to Section III of the General Terms & Conditions, provided however, the total Maximum Quantity Stored in the field shall not exceed 4.8 BCF and provided that each Buyer shall receive its allowable share of same.

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

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

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

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).
2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.
3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

Rate Sch. (1)	Rate Component (2)		Base Rate (3)	FERC ACA (4)	Current Rate 1/ (5)
IT	Commodity	(Max)	$0.1168	0.0019	$0.1187
		(Min)	0.0000	0.0019	$0.0019
	Overrun	(Max)	0.1168	0.0019	$0.1187
		(Min)	0.0000	0.0019	$0.0019
IG	Commodity	(Max)	5.1000	-	$5.1000
		(Min)	0.0069	-	$0.0069
FG	Reservation	(Max)	0.0000	-	$0.0000
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0069	0.0019	$0.0088
		(Min)	0.0069	0.0019	$0.0088
	Overrun	(Max)	5.1000	0.0019	$5.1019
		(Min)	5.1000	0.0019	$5.1019
X-58 Conversion Surcharge					
	Reservation	(Max)	0.1221	-	$0.1221
		(Min)	-	-	-
	Commodity	(Max)	-	-	-
		(Min)	-	-	-
W-1	Commodity	(Max)	0.0252	0.0019	$0.0271
		(Min)	0.0000	-	$0.0000
	Overrun	(Max)	0.0252	0.0019	$0.0271
		(Min)	0.0000	-	$0.0000
	Fly-By Rate	(Max)	0.0100	-	$0.0100
		(Min)	0.0000	-	$0.0000
IR-1	First Day	(Max)	0.0532	0.0019	$0.0551
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0028	-	$0.0028
	Day	(Min)	0.0000	-	$0.0000
IR-2	First Day	(Max)	0.0028	-	$0.0028
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0028	-	$0.0028
	Day	(Min)	0.0000	-	$0.0000
FST	Reservation	(Max)	3.3612	-	$3.3612
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0063	0.0019	$0.0082
		(Min)	0.0063	0.0019	$0.0082
	Overrun	(Max)	0.1168	0.0019	$0.1187
		(Min)	0.0063	0.0019	$0.0082
	Maximum Volumetric Rate		0.1168	0.0019	$0.1187

1/ All rates exclusive of Fuel and Company Use retention and Transportation LAUF retention. Fuel and Company Use retention for all applicable rate schedules is 1.15%. Transportation LAUF retention for all applicable rate schedules is 0.25%. Transporter may from time to time identify point pair transactions where the Fuel and Company Use retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the Transportation LAUF retention of 0.25%.

Rate Sch. (1)	Rate Component (2)			Base Rate (3)	FERC ACA (4)	Current Rate 2/ (5)
ESS	Demand	(Max)		$2.1345	-	$2.1345
		(Min)		0.0000	-	$0.0000
	Capacity	(Max)		0.0432	-	$0.0432
		(Min)		0.0000	-	$0.0000
	Injection/	(Max)		0.0139	0.0019	$0.0158
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/			0.0702	0.0019	$0.0721
	Max. Volumetric Cap. Rate 4/			0.0014	-	$0.0014
	Storage Balance Transfer	(Max)	5/	3.8600	-	$3.8600
		(Min)	5/	0.0000	-	$0.0000
ISS	Injection	(Max)		1.0635	0.0019	$1.0654
		(Min)		0.0000	-	$0.0000
	Storage Balance Transfer	(Max)	5/	3.8600	-	$3.8600
		(Min)	5/	0.0000	-	$0.0000
IAS	Usage	(Max)	1/	0.0028	-	$0.0028
		(Min)	1/	0.0000	-	$0.0000
	Advance/Return	(Max)		0.0139	0.0019	$0.0158
		(Min)		0.0000	-	$0.0000
FSS	Demand	(Max)		2.1556	-	$2.1556
		(Min)		0.0000	-	$0.0000
	Capacity	(Max)		0.0432	-	$0.0432
		(Min)		0.0000	-	$0.0000
	Injection/	(Max)		0.0139	0.0019	$0.0158
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/			0.0709	0.0019	$0.0728
	Max. Volumetric Cap. Rate 4/			0.0014	-	$0.0014
	Storage Balance Transfer	(Max)	5/	3.8600	-	$3.8600
		(Min)	5/	0.0000	-	$0.0000
P-1	First Day	(Max)		0.0575	0.0019	$0.0594
		(Min)		0.0000	-	$0.0000
	Each Subsequent	(Max)		0.0071	-	$0.0071
	Day	(Min)		0.0000	-	$0.0000
P-2	First Day	(Max)		0.0071	-	$0.0071
		(Min)		0.0000	-	$0.0000
	Each Subsequent	(Max)		0.0071	-	$0.0071
	Day	(Min)		0.0000	-	$0.0000

1/ Unit Dth Rates per day.
2/ All rates exclusive of Surface Operating Allowance and Storage LAUF retention, where applicable. Surface Operating Allowance for all applicable rate schedules is 1.17%. Storage LAUF retention for all applicable rate schedules is 0.23%.
3/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
4/ Assessed per dekatherm per day on storage balance.
5/ Rate per nomination.

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$27.4017	---------	$27.4017
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$52.0632	---------	$52.0632
	-- Minimum	$00.0000	---------	$00.0000
	Short Term Recourse Reservation Rate			
	-- Maximum	$68.5042	---------	$68.5042
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0019	$00.0019
	-- Minimum	$00.0000	$00.0019	$00.0019
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$18.3920	-------	$18.3920
	--Minimum	$00.0000	-------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.2962	$00.0019	$00.2981
	--Minimum	$00.0000	$00.0019	$00.0019
IT	Recourse Usage Rate			
	-- Maximum	$02.2522	$00.0019	$02.2541
	-- Minimum	$00.0000	$00.0019	$00.0019

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 17 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-A Reservation Rate is $0.00 per Dth

Notes:
1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
2/ Maximum rates are inclusive of base rates and above surcharges.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/						
Segment U	$9.65			$0.00	$9.65	
Segment 1	$1.33			$0.00	$1.33	
Segment 2	$8.08			$0.00	$8.08	
Segment 3	$5.07			$0.00	$5.07	
Segment 4	$5.54			$0.00	$5.54	
Commodity Rate 2/, 3/						
Segments U, 1, 2, 3 & 4		$0.0019			$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/						
Segment U	$0.3173				$0.3173	5.52%
Segment 1	$0.0437				$0.0437	0.69%
Segment 2	$0.2656				$0.2656	0.59%
Segment 3	$0.1667				$0.1667	0.73%
Segment 4	$0.1821				$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 220A.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (TCSM) (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.02	$0.00	$2.02	
Space Rate	$0.0248	$0.0000	$0.0248	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	
Overrun Rate	$0.2427		$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.15	$0.00	$1.15	
Space Rate	$0.0185	$0.0000	$0.0185	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
Overrun Rate	$0.1380		$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA				
Space Rate	$0.0848	$0.0000	$0.0848	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA				
Space Rate	$0.0993	$0.0000	$0.0993	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

TransCanada
In business to deliver

Canadian and Export Transportation Tolls

Approved 2008 Final Tolls

(Final Tolls are unchanged from the effective June Approved Interim Tolls)

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	100% LF Toll ($/GJ)
	(a)	(b)	(c)	(d)
	Canadian Firm Transportation			
1	Saskatchewan Zone	6.23698	0.01969	0.22418
2	Manitoba Zone	12.28548	0.03684	0.43964
3	Western Zone	20.07405	0.06391	0.72208
4	Northern Zone	30.41993	0.09601	1.09338
5	North Bay Junction	33.33775	0.10736	1.20040
6	Eastern Zone	38.93622	0.12339	1.39999
7	Southwest Zone	33.37110	0.10747	1.20160
	Export Firm Transportation			
8	Empress to Emerson	13.91324	0.04241	0.49858
9	Empress to St. Clair	33.33105	0.10733	1.20015
10	Empress to Chippawa	37.64493	0.12015	1.35441
11	Empress to Niagara Falls	37.61530	0.12005	1.35334
12	Empress to Iroquois	38.67452	0.12520	1.39322
13	Empress to Cornwall	39.30207	0.12701	1.41560
14	Empress to Philipsburg	41.46266	0.13423	1.49366
15	Empress to Napierville	41.24620	0.13351	1.48584
16	Empress to East Hereford	43.75566	0.14190	1.57651
	Shorthaul Firm Transportation			
17	Emerson to Union Gas - CDA	23.79583	0.07533	0.85552
18	Emerson to Niagara	24.66575	0.07836	0.88707
19	Emerson to Chippawa	24.69537	0.07846	0.88814
20	Dawn to Enbridge Gas - CDA	4.86708	0.01215	0.17173
21	Dawn to Enbridge Gas - EDA	9.85413	0.02893	0.35202
22	Dawn to Union Gas - CDA	4.08382	0.00943	0.14333
23	Dawn to Union Gas - EDA	8.09049	0.02304	0.28830
24	Dawn to Gaz Métropolitain - EDA	11.76913	0.03554	0.42141
25	Dawn to Iroquois	9.32811	0.02709	0.33293
26	Dawn to Niagara	4.95188	0.01245	0.17481
27	Dawn to Chippawa	4.98151	0.01255	0.17588
28	Dawn to East Hereford	14.26916	0.04360	0.51144
29	Dawn to Philipsburg	11.97616	0.03594	0.42860
30	Kirkwall to Chippawa	2.64252	0.00473	0.09137
31	Parkway to Union Gas- EDA	5.27656	0.01363	0.18663
32	Parkway to Iroquois	6.51542	0.01768	0.23130
33	Parkway to Enbridge Gas - CDA	2.16907	0.00312	0.07424
34	Parkway to Gaz Métropolitain - EDA	8.95644	0.02613	0.31978
35	Parkway to Philipsburg	9.16348	0.02653	0.32697
36	St. Clair to Union SWDA	1.26791	0.00014	0.04171
37	St. Clair to Chippawa	5.27694	0.01354	0.18655
38	St. Clair to East Hereford	14.56459	0.04459	0.52212

* All tolls are expressed and payable in Canadian Dollars.

TransCanada
In business to deliver

Canadian and Export Transportation Tolls

Approved 2008 Final Tolls

(Final Tolls are unchanged from the effective June Approved Interim Tolls)

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
	Storage Transportation Service		
1	Centra Gas Manitoba - MDA	3.00917	0.00645
2	Union Gas - WDA	19.73333	0.06161
3	Union Gas - NDA	7.88583	0.02282
4	Union Gas - EDA	5.17667	0.01335
5	Kingston PUC	4.99417	0.01260
6	Gaz Metropolitain - EDA	8.95667	0.02613
7	Enbridge - CDA	1.29667	0.00022
8	Enbridge - EDA	3.26250	0.00700
9	Cornwall	7.00250	0.01931
10	Philipsburg	9.16333	0.02653

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
	Enhanced Capacity Release	
11	ECR Surcharge	0.040

Line No	Delivery Pressure	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
1	Emerson - 1 (Viking)	0.04565	0.00000	0.00150
2	Emerson - 2 (Great Lakes)	0.05944	0.00000	0.00195
3	Dawn	0.06461	0.00000	0.00212
4	Niagara Falls	0.09325	0.00000	0.00306
5	Iroquois	0.49571	0.00000	0.01625
6	Chippawa	0.85681	0.00000	0.02809
7	East Hereford	1.46897	0.01895	0.06711

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

System Average Unit Cost of Transportation

Line No	Particulars	Functionalized ($000's)	Applicable Allocation Units (GJ)	Unit Costs
	(a)	(b)	(c)	(d)
8	Fixed Energy - ($/GJ)	94,343	6,409,367	14.7195503082
9	Transmission - Variable - ($/GJ-km)	91,548	2,208,799,890,501	0.0000414471
10	Transmission - Fixed - ($/GJ-km)	1,463,914	9,840,308,746	0.1487670475

RATES AND STATISTICS

Exchange Rates

Text + – R Print

Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 18 Aug 2008

NEW: The following currencies are now available for converting: Serbian Dinar, Romanian Ron and UAE Dirham. The start date for these new currencies is 3 September 2007.

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

Currency:	U.S. dollar
Amount:	1.00
Convert:	(•) **from $Can** ( ) **to $Can**
Use the:	(•) Nominal rate HELP ( ) Cash rate (4%) HELP
Answer:	0.94 CONVERT
Exchange rate:	0.9430

Summary:

On 18 Aug 2008, 1.00 Canadian dollar(s) = 0.94 U.S. dollar (s), at an exchange rate of 0.9430 (using nominal rate.)

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

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

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

More comprehensive currency converters are available elsewhere on the web. You may want to try **hifx.com** or **oanda.com**.

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

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

00000029

Line									
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2008 - 2009 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 62 * ln 101							
13	Niagara Supply	ln 63 * ln 106							
14	TGP Supply (Direct)	ln 64 * ln 114							
15	TGP Zone 6 Purchases	ln 65 * ln 117							
16	Dracut Winter Supply	ln 66 * ln 111							
17	City Gate Delivered Supply	ln 67 * ln 122							
18	LNG Truck	ln 68 * ln 124							
19	Propane Truck	ln 69 * ln 126							
20	PNGTS	ln 70 * ln 131							
21	Granite Ridge	ln 71 * ln 136							
22									
23	Subtotal Pipeline Gas Costs		$ 10,175,002	$ 16,613,123	$ 18,568,128	$ 15,623,711	$ 9,139,468	$ 8,853,621	$ 78,973,053
24									
25	**Volumetric Transportation Costs**								
26	Dawn Supply	ln 62 * ln 183							
27	Niagara Supply	ln 63 * ln 194							
28	TGP Supply (Direct)	ln 64 * ln 221							
29	TGP Zone 6 Purchases	ln 65 * ln 231							
30	Dracut Winter Supply	ln 66 * ln 242							
31	TGP Storage - Withdrawals	ln 76 * ln 158							
32									
33	**Total Volumetric Transportation Costs**		$ 635,428	$ 747,919	$ 855,610	$ 726,865	$ 800,141	$ 522,466	$ 4,288,429
34									
35	**Less - Gas Refill:**								
36	LNG Truck	ln 85 * ln 143							
37	Propane	ln 86 * ln 144							
38	TGP Storage Refill	ln 87 * ln 114							
39	Storage Refill (Trans.)	ln 87 * ln 221							
40									
41	Subtotal Refills		$ (937,737)	$ (218,076)	$ (1,488,501)	$ (285,371)	$ (208,802)	$ (415,185)	$ (3,553,671)
42									
43	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 33 + ln 41	$ 9,872,693	$ 17,142,966	$ 17,935,237	$ 16,065,205	$ 9,730,807	$ 8,960,902	$ 79,707,811
44									
45	**Storage Gas:**								
46	TGP Storage - Withdrawals	ln 76 * ln 150	$ 1,475,445	$ 2,368,205	$ 4,293,047	$ 2,851,733	$ 5,352,792	$ -	$ 16,341,221
47									
48	**Produced Gas:**								
49	LNG Vapor	ln 79 * ln 138							
50	Propane	ln 80 * ln 140							
51									
52	**Total Produced Gas**	ln 49 + ln 50	$ 170,252	$ 350,838	$ 1,327,640	$ 591,001	$ 202,800	$ 23,464	$ 2,665,995
53									
54									
55	**Total Commodity Gas & Trans. Costs**	ln 43 + ln 46 + ln 52	$ 11,518,390	$ 19,862,009	$ 23,555,924	$ 19,507,938	$ 15,286,399	$ 8,984,366	$ 98,715,027
56									
57									

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line									
5									Peak
6	For Month of:	Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
58									
59	**Volumes (Therms)**								
60									
61	**Pipeline Gas:**	See Schedule 11A							
62	Dawn Supply		1,065,528	1,100,655	1,100,655	994,373	1,100,655	1,068,230	6,430,097
63	Niagara Supply		843,956	871,878	871,878	787,212	871,878	843,956	5,090,756
64	TGP Supply (Direct)		5,835,635	5,624,872	5,945,521	5,262,790	6,030,187	5,835,635	34,534,639
65	TGP Zone 6 Purchases		-	-	-	-	-	1,052,918	1,052,918
66	Dracut Winter Supply		1,054,720	5,488,866	5,494,270	4,953,850	370,188	-	17,361,893
67	City Gate Delivered Supply		2,161,680	2,233,736	2,233,736	2,017,568	915,111	1,001,578	10,563,410
68	LNG Truck		225,175	237,785	360,280	302,635	225,175	-	1,351,050
69	Propane Truck		-	-	562,938	-	-	-	562,938
70	PNGTS		29,723	38,730	44,134	37,829	34,227	25,220	209,863
71	Granite Ridge		-	-	-	-	-	-	-
72									
73	Subtotal Pipeline Volumes		11,216,417	15,596,521	16,613,412	14,356,257	9,547,420	9,827,538	77,157,565
74									
75	**Storage Gas:**								
76	TGP Storage		1,730,245	2,761,546	5,006,091	3,325,384	6,241,851	-	19,065,117
77									
78	**Produced Gas:**								
79	LNG Vapor		225,175	237,785	416,123	288,224	217,969	25,220	1,410,496
80	Propane		-	96,375	562,938	190,948	-	-	850,261
81									
82	Subtotal Produced Gas		225,175	334,160	979,061	479,172	217,969	25,220	2,260,757
83									
84	**Less - Gas Refill:**								
85	LNG Truck		(225,175)	(237,785)	(360,280)	(302,635)	(225,175)	-	(1,351,050)
86	Propane		-	-	(562,938)	-	-	-	(562,938)
87	TGP Storage Refill		(768,297)	-	-	-	-	(432,336)	(1,200,633)
88									
89	Subtotal Refills		(993,472)	(237,785)	(923,218)	(302,635)	(225,175)	(432,336)	(3,114,621)
90									
91	**Total Sendout Volumes**		12,178,365	18,454,442	21,675,346	17,858,179	15,782,065	9,420,421	95,368,818
92									
93									
94									

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Ln									
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2008 - 2009 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
95	**Gas Costs and Volumetric Transportation Rates**								Average Rate
96									
97	**Pipeline Gas:**								
98	**Dawn Supply**								
99	NYMEX Price	Sch 7, ln 10/10							
100	Basis Differential								
101	**Net Commodity Costs**								
102									
103	**Niagara Supply**								
104	NYMEX Price	Sch 7, ln 10/10							
105	Basis Differential								
106	**Net Commodity Costs**								
107									
108	**Dracut Winter Supply**								
109	**Commodity Costs - NYMEX Price**	Sch 7, ln 10 / 10							
110	**Basis Differential**								
111	**Net Commodity Costs**								
112									
113	**TGP Supply (Direct)**								
114	NYMEX Price	Sch 7, ln 10/10	$0.8769	$0.9171	$0.9409	$0.9430	$0.9273	$0.8837	**$0.9148**
115									
116	**TGP Zone 6 Purchases**								
117	**Commodity Costs - NYMEX Price**	Sch 7, ln 10/10	$0.8769	$0.9171	$0.9409	$0.9430	$0.9273	$0.8837	**$0.9148**
118									
119	**City Gate Delivered Supply**								
120	**NYMEX Price**	Sch 7, ln 10/10							
121	**Basis Differential**								
122	**Net Commodity Costs**								
123									
124	**LNG Truck**	Sch 7, ln 10/10	**$0.8769**	**$0.9171**	**$0.9409**	**$0.9430**	**$0.9273**	**$0.8837**	**$0.9148**
125									
126	**Propane Truck**	NYMEX - Propane	**$2.0210**	**$2.0310**	**$2.0420**	**$2.0200**	**$1.9920**	**$1.9400**	**$2.0077**
127									
128	**PNGTS**								
129	NYMEX Price	Sch 7, ln 10/10							
130	Additional Cost								
131	**Net Commodity Cost**								
132									
133	**Granite Ridge**								
134	NYMEX Price	Sch 7, ln 10/10							
135	Additional Cost								
136	**Net Commodity Cost**								
137									
138	**LNG Vapor (Storage)**	Sch 16, ln 103 /10	**$0.7561**	**$0.8603**	**$0.9195**	**$0.9384**	**$0.9304**	**$0.9304**	**$0.8892**
139									
140	**Propane**	Sch 16, ln 65 /10	**$1.5178**	**$1.5178**	**$1.6787**	**$1.6787**	**$1.6787**	**$1.6787**	**$1.6251**
141									
142	**Storage Refill:**								
143	**LNG Truck**	ln 124	**$0.8769**	**$0.9171**	**$0.9409**	**$0.9430**	**$0.9273**	**$0.8837**	**$0.8892**
144	**Propane**	ln 126	**$2.0210**	**$2.0310**	**$2.0420**	**$2.0200**	**$1.9920**	**$1.9400**	**$1.6251**
145									
146						**THIS PAGE HAS BEEN REDACTED**			

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln	For Month of: (a)	Reference (b)	Nov-08 (c)	Dec-08 (d)	Jan-09 (e)	Feb-09 (f)	Mar-09 (g)	Apr-09 (h)	Peak Nov- Apr (i)
147									
148									Average Rate
149	**TGP Storage**								
150	**Commodity Costs - Storage withdrawal**	Sch 16, ln 26 /10	$0.8527	$0.8576	$0.8576	$0.8576	$0.8576	$0.8576	$0.8568
151									
152	TGP - Max Commodity - Z 4-6	19th Rev Sheet No. 23A	$0.00834	$0.00834	$0.00834	$0.00834	$0.00834	$0.00834	$0.00834
153	TGP - Max Comm. ACA Rate - Z 4-6	19th Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
154	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.00853	$0.00853	$0.00853	$0.00853	$0.00853	$0.00853	$0.00853
155	TGP - Fuel Charge % - Z 4-6	3rd Rev Sheet No. 29	2.17%	2.17%	2.17%	2.17%	2.17%	1.92%	2.13%
156	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.01850	$0.01861	$0.01861	$0.01861	$0.01861	$0.01647	$0.01823
157	TGP - Withdrawal Charge	17th Rev Sheet No. 27	$0.00102	$0.00102	$0.00102	$0.00102	$0.00102	$0.00102	$0.00102
158	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.02805	$0.02816	$0.02816	$0.02816	$0.02816	$0.02602	$0.02778
159									
160	**Total TGP - Comm. & Vol. Trans. Rate**	ln 150 + ln 158	**$0.88079**	**$0.88572**	**$0.88572**	**$0.88572**	**$0.88572**	**$0.88358**	**$0.88454**
161									
162									
163	**Per Unit Volumetric Transportation Rates**								
164	**Dawn Supply Volumetric Transportation Charge**								
165	**Commodity Costs**	ln 101							
166									
167	TransCanada - Commodity Rate/GJ	Union Dawn to Iroquois	$0.00271	$0.00271	$0.00271	$0.00271	$0.00271	$0.00271	$0.00271
168	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
169	Conversion Rate to US$	8/18/2008	0.9430	0.9430	0.9430	0.9430	0.9430	0.9430	0.9430
170	Commodity Rate/US$	ln 167 x ln 168 x ln 169	$0.00270	$0.00270	$0.00270	$0.00270	$0.00270	$0.00270	$0.00270
171	TransCanada Fuel %	Union Dawn to Iroquois	1.44%	1.39%	1.53%	1.19%	1.49%	1.05%	1.35%
172	TransCanada Fuel * Percentage	ln 165 x ln 171	$0.01312	$0.01322	$0.01492	$0.01163	$0.01432	$0.00964	$0.01281
173	Subtotal TransCanada		**$0.01581**	**$0.01592**	**$0.01761**	**$0.01432**	**$0.01702**	**$0.01233**	**$0.01550**
174	IGTS - Z1 RTS Commodity	30th Rev Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
175	IGTS - Z1 RTS ACA Rate Commodity	19th Rev Sheet 4A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
176	IGTS - Z1 RTS Deferred Asset Surcharge	19th Rev Sheet 4A	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005
177	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00054**	**$0.00054**	**$0.00054**	**$0.00054**	**$0.00054**	**$0.00054**	**$0.00054**
178	TGP NET-NE - Comm. Segments 3 & 4	41st Rev Sheet No. 26B	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
179	IGTS -Fuel Use Factor - Percentage	19th Rev Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
180	IGTS -Fuel Use Factor - Fuel * Percentage	ln 165 x ln 179	**$0.00911**	**$0.00951**	**$0.00975**	**$0.00977**	**$0.00961**	**$0.00918**	**$0.00949**
181	TGP NET-284 - Fuel Charge % Z 4-6	5th Rev Sheet 220A	1.54%	1.54%	1.54%	1.54%	1.54%	1.54%	1.54%
182	TGP NET-284 -Fuel Use Factor - Fuel * %	ln 165 x ln 181	**$0.01403**	**$0.01465**	**$0.01501**	**$0.01505**	**$0.01480**	**$0.01413**	**$0.01461**
183	**Total Volumetric Transportation Charge - Waddington Supply A**		**$0.03968**	**$0.04080**	**$0.04310**	**$0.03987**	**$0.04217**	**$0.03637**	**$0.04033**
184									
185									
186	**Niagara Supply Volumetric Transportation Charge**								
187	**Commodity Costs**	Ln 106							
188									
189	TGP FTA - FTA Z 5-6 Comm. Rate	19th Rev Sheet No. 23A							
190	TGP FTA - FTA Z 5-6 - ACA Rate	19th Rev Sheet No. 23A							
191	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
192	TGP FTA Fuel Charge % Z 5-6	3rd Rev Sheet No. 29							
193	TGP FTA Fuel * Percentage	ln 187 x ln 192							
194	**Total Volumetric Transportation Rate - Niagra Supply**								
195									
196									

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Ln	For Month of:	Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Nov- Apr
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2008 - 2009 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
198									
199									
200	**TGP Direct Volumetric Transportation Charge**								Average Rate
201	**Commodity Costs**	Ln 114	**$0.8769**	**$0.9171**	**$0.9409**	**$0.9430**	**$0.9273**	**$0.8837**	**$0.9148**
202									
203	TGP - Max Comm. Base Rate - Z 0-6	19th Rev Sheet No. 23A	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608
204	TGP - Max Commodity ACA Rate - Z 0-6	19th Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
205	Subtotal TGP - Max Comm. Rate Z 0-6		$0.01627	$0.01627	$0.01627	$0.01627	$0.01627	$0.01627	$0.01627
206	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
207	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**
208	TGP - Max Comm. Base Rate - Z 1-6	19th Rev Sheet No. 23A	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503
209	TGP - Max Commodity ACA Rate - Z 1-6	19th Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
210	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.01522	$0.01522	$0.01522	$0.01522	$0.01522	$0.01522	$0.01522
211	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
212	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**
213	TGP - Fuel Charge % - Z 0 -6	3rd Rev Sheet No. 29	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.50%
214	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
215	Prorated TGP Fuel Charge % - Z 0-6		2.84%	2.84%	2.84%	2.84%	2.84%	2.42%	2.77%
216	TGP - Fuel Charge % - Z 1 -6	3rd Rev Sheet No. 29	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	7.63%
217	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
218	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		5.27%	5.27%	5.27%	5.27%	5.27%	4.50%	5.14%
219	TGP - Fuel Charge % - Z 0-6	ln 201 x ln 215	**$0.02490**	**$0.02604**	**$0.02672**	**$0.02677**	**$0.02633**	**$0.02138**	**$0.02536**
220	TGP - Fuel Charge % - Z 1-6	ln 201 x ln 218	**$0.04622**	**$0.04834**	**$0.04959**	**$0.04970**	**$0.04887**	**$0.03973**	**$0.04707**
221	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.08668**	**$0.08994**	**$0.09187**	**$0.09204**	**$0.09077**	**$0.07666**	**$0.08799**
222									
223	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
224	**Commodity Costs**	Ln 117	**$0.8769**	**$0.9171**	**$0.9409**	**$0.9430**	**$0.9273**	**$0.8837**	**$0.9148**
225									
226	TGP - Max Comm. Base Rate - Z 6-6	19th Rev Sheet No. 23A	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642
227	TGP - Max Commodity ACA Rate - Z 6-6	19th Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
228	Subtotal TGP - Max Commodity Rate - Z 4-6		**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**
229	TGP - Fuel Charge % - Z 6-6	3rd Rev Sheet No. 29	0.89%	0.89%	0.89%	0.89%	0.89%	0.85%	0.88%
230	TGP - Fuel Charge	ln 224 x ln 229	**$0.00780**	**$0.00816**	**$0.00837**	**$0.00839**	**$0.00825**	**$0.00751**	**$0.00808**
231	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.01441**	**$0.01477**	**$0.01498**	**$0.01500**	**$0.01486**	**$0.01412**	**$0.01469**
232									
233									
234	**TGP Dracut**								
235	**Commodity Costs - NYMEX Price**	Ln 111							
236									
237	TGP - Trans Charge - Comm. - Z 6-6	19th Rev Sheet No. 23A							
238	TGP - Trans Charge - ACA Rate - Z6-6	19th Rev Sheet No. 23A							
239	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
240	TGP - Fuel Charge % - Z 6-6	3rd Rev Sheet No. 29							
241	TGP - Fuel Charge	ln 235 x ln 240							
242	**Total Volumetric Transportation Rate - TGP Dracut**								
243									
244									

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

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

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

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

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

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

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:		
Commodity	0.0019	
DEFERRED ASSET SURCHARGE:		
Commodity		
Zone 1	0.0005	
Zone 2	0.0003	
Inter-Zone	0.0008	
MEASUREMENT VARIANCE/FUEL USE FACTOR:		
Minimum		0.00%
Maximum (Non-Eastchester Shipper)		1.00%
Maximum (Eastchester Shipper)		4.50%

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0458		$0.0688	$0.0899	$0.0997	$0.1137	$0.1250	$0.1627
L		$0.0305						
1	$0.0688		$0.0591	$0.0795	$0.0893	$0.1033	$0.1145	$0.1522
2	$0.0899		$0.0795	$0.0452	$0.0549	$0.0700	$0.0802	$0.1178
3	$0.0997		$0.0893	$0.0549	$0.0385	$0.0682	$0.0784	$0.1161
4	$0.1148		$0.1044	$0.0700	$0.0682	$0.0420	$0.0478	$0.0853
5	$0.1250		$0.1145	$0.0802	$0.0784	$0.0478	$0.0446	$0.0784
6	$0.1627		$0.1522	$0.1178	$0.1161	$0.0853	$0.0784	$0.0661

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/						
Segment U	$9.65			$0.00	$9.65	
Segment 1	$1.33			$0.00	$1.33	
Segment 2	$8.08			$0.00	$8.08	
Segment 3	$5.07			$0.00	$5.07	
Segment 4	$5.54			$0.00	$5.54	
Commodity Rate 2/, 3/						
Segments U, 1, 2, 3 & 4		$0.0019			$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/						
Segment U	$0.3173				$0.3173	5.52%
Segment 1	$0.0437				$0.0437	0.69%
Segment 2	$0.2656				$0.2656	0.59%
Segment 3	$0.1667				$0.1667	0.73%
Segment 4	$0.1821				$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 220A.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (TCSM) (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.02	$0.00	$2.02	
Space Rate	$0.0248	$0.0000	$0.0248	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	
Overrun Rate	$0.2427		$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.15	$0.00	$1.15	
Space Rate	$0.0185	$0.0000	$0.0185	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
Overrun Rate	$0.1380		$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA				
Space Rate	$0.0848	$0.0000	$0.0848	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA				
Space Rate	$0.0993	$0.0000	$0.0993	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

NET-284 RATE SCHEDULE (continued)

Shipper	Transportation Quantity (Dth)	Segments U	1	2	3	4	Fuel and Use
Bay State (from Granite) - Pleasant St.	3,706				*	*	1.26%
Bay State (from Granite) - Agawam	6,068				*		0.96%
Boston Gas	35,000				*	*	1.31%
Boston Gas	8,600				*	*	1.31%
Dartmouth Power	14,010				*	*	1.23%
EnergyNorth Natural Gas, Inc.	4,000				*	*	1.54%
Essex County Gas Company	2,000				*	*	1.44%
Iroquois (Connecticut Natural, Yankee Gas)	37,000				*		0.68%
Lockport Energy Associates	28,000	*	*				6.21%
Northern Utilities (from Granite) Pleasant St.	844				*	*	1.26%
Northern Utilities (from Granite) Agawam	1,382				*		0.96%
Project Orange	20,000		*	*			1.28%
Valley Gas Company	1,000				*	*	1.25%
Yankee Gas (Wright)	9,000				*		1.07%
Total	170,610						

TransCanada
In business to deliver

Canadian and Export Transportation Tolls

Approved 2008 Final Tolls

(Final Tolls are unchanged from the effective June Approved Interim Tolls)

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	100% LF Toll ($/GJ)
	(a)	(b)	(c)	(d)
	Canadian Firm Transportation			
1	Saskatchewan Zone	6.23698	0.01969	0.22418
2	Manitoba Zone	12.28548	0.03684	0.43964
3	Western Zone	20.07405	0.06391	0.72208
4	Northern Zone	30.41993	0.09601	1.09338
5	North Bay Junction	33.33775	0.10736	1.20040
6	Eastern Zone	38.93622	0.12339	1.39999
7	Southwest Zone	33.37110	0.10747	1.20160
	Export Firm Transportation			
8	Empress to Emerson	13.91324	0.04241	0.49858
9	Empress to St. Clair	33.33105	0.10733	1.20015
10	Empress to Chippawa	37.64493	0.12015	1.35441
11	Empress to Niagara Falls	37.61530	0.12005	1.35334
12	Empress to Iroquois	38.67452	0.12520	1.39322
13	Empress to Cornwall	39.30207	0.12701	1.41560
14	Empress to Philipsburg	41.46266	0.13423	1.49366
15	Empress to Napierville	41.24620	0.13351	1.48584
16	Empress to East Hereford	43.75566	0.14190	1.57651
	Shorthaul Firm Transportation			
17	Emerson to Union Gas - CDA	23.79583	0.07533	0.85552
18	Emerson to Niagara	24.66575	0.07836	0.88707
19	Emerson to Chippawa	24.69537	0.07846	0.88814
20	Dawn to Enbridge Gas - CDA	4.86708	0.01215	0.17173
21	Dawn to Enbridge Gas - EDA	9.85413	0.02893	0.35202
22	Dawn to Union Gas - CDA	4.08382	0.00943	0.14333
23	Dawn to Union Gas - EDA	8.09049	0.02304	0.28830
24	Dawn to Gaz Métropolitain - EDA	11.76913	0.03554	0.42141
25	Dawn to Iroquois	9.32811	0.02709	0.33293
26	Dawn to Niagara	4.95188	0.01245	0.17481
27	Dawn to Chippawa	4.98151	0.01255	0.17588
28	Dawn to East Hereford	14.26916	0.04360	0.51144
29	Dawn to Philipsburg	11.97616	0.03594	0.42860
30	Kirkwall to Chippawa	2.64252	0.00473	0.09137
31	Parkway to Union Gas- EDA	5.27656	0.01363	0.18663
32	Parkway to Iroquois	6.51542	0.01768	0.23130
33	Parkway to Enbridge Gas - CDA	2.16907	0.00312	0.07424
34	Parkway to Gaz Métropolitain - EDA	8.95644	0.02613	0.31978
35	Parkway to Philipsburg	9.16348	0.02653	0.32697
36	St. Clair to Union SWDA	1.26791	0.00014	0.04171
37	St. Clair to Chippawa	5.27694	0.01354	0.18655
38	St. Clair to East Hereford	14.56459	0.04459	0.52212

* All tolls are expressed and payable in Canadian Dollars.

TransCanada Fuel Ratios

November-2007

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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For fuel ratios or bid tolls questions please contact Peter Exall (1.403.920.5398).

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.2695	1.44	0.96

December-2007

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.2695	1.39	0.91

January-2008

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.2828	1.53	1.05

February-2008

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.2828	1.19	0.71

March-2008

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.2828	1.49	1.01

April-2008

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3428	1.05	0.57

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Ln		Reference		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Strip Average
5										
6	For Month of:	Reference		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**									
9		Opening Prices (15 day average)								
10		NYMEX	8/4-8/22	8.7687	9.1711	9.4089	9.4295	9.2729	8.8367	$ 9.1480
		11/26/2008								
11		12/24/2008								
12		1/25/2009								
13		2/25/2009								
14		3/25/2009								
15										
16										
17										
18	**II. Development of Hedging Costs and Savings**									
19										
20	**TGP (Direct) Volumes**									Total
21	Hedged Volumes (Dth)	ln 102		600,000	955,000	1,080,000	1,020,000	755,000	660,000	5,070,000
22	Market Priced Volumes (Dth)			496,152	577,001	484,606	381,579	173,802	320,232	2,433,371
23	Total Volumes (Dth)	Sch 6, lns 62 - 67 / 10		1,096,152	1,532,001	1,564,606	1,401,579	928,802	980,232	7,503,371
24	Percentage of Volumes Hedged	ln 21 / ln 23		59%	61%	68%	75%	78%	68%	67.6%
25										Weighted Average
26	Hedge Price	ln 233		$ 9.4487	$ 9.7786	$ 10.0262	$ 9.9967	$ 9.8125	$ 8.6611	$ 9.6958
27	NYMEX Price	ln 10		$ 8.7687	$ 9.1711	$ 9.4089	$ 9.4295	$ 9.2729	$ 8.8367	$ 9.1977
28										
29	Hedged Volumes at Hedged Price	ln 21 * ln 26		$ 5,669,236	$ 9,338,549	$ 10,828,276	$ 10,196,657	$ 7,408,443	$ 5,716,350	$ 49,157,511
30	Less Hedged Volumes at NYMEX	ln 22 * ln 27		5,261,200	8,758,432	10,161,576	9,618,124	7,001,014	5,832,200	46,632,547
31										
32	Hedge Contract (Savings)/Loss	ln 29 - ln 30		$ 408,036	$ 580,117	$ 666,700	$ 578,533	$ 407,429	$ (115,850)	$ 2,524,964
33										
34										
35										
36										
37										
38										

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line					Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Strip Average
5											
6	For Month of:			Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Strip Average
7	(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
39											
40	Hedged Volumes (Dth)										
41	Hedge 1	Trade Date	4-May-07	Swaps							
42	Hedge 2	Trade Date	4-May-07	Swaps							
43	Hedge 3	Trade Date	18-May-07	Swaps							
44	Hedge 4	Trade Date	18-May-07	Swaps							
45	Hedge 5	Trade Date	8-Jun-07	Swaps							
46	Hedge 6	Trade Date	8-Jun-07	Swaps							
47	Hedge 7	Trade Date	22-Jun-07	Swaps							
48	Hedge 8	Trade Date	22-Jun-07	Swaps							
49	Hedge 9	Trade Date	9-Jul-07	Swaps							
50	Hedge 10	Trade Date	9-Jul-07	Swaps							
51	Hedge 11	Trade Date	20-Jul-07	Swaps							
52	Hedge 12	Trade Date	20-Jul-07	Swaps							
53	Hedge 13	Trade Date	3-Aug-07	Swaps							
54	Hedge 14	Trade Date	3-Aug-07	Swaps							
55	Hedge 15	Trade Date	17-Aug-07	Swaps							
56	Hedge 16	Trade Date	17-Aug-07	Swaps							
57	Hedge 17	Trade Date	7-Sep-07	Swaps							
58	Hedge 18	Trade Date	7-Sep-07	Swaps							
59	Hedge 19	Trade Date	21-Sep-07	Swaps							
60	Hedge 20	Trade Date	21-Sep-07	Swaps							
61	Hedge 21	Trade Date	5-Oct-07	Swaps							
62	Hedge 22	Trade Date	5-Oct-07	Swaps							
63	Hedge 23	Trade Date	19-Oct-07	Swaps							
64	Hedge 24	Trade Date	19-Oct-07	Swaps							
65	Hedge 25	Trade Date	2-Nov-07	Swaps							
66	Hedge 26	Trade Date	2-Nov-07	Swaps							
67	Hedge 27	Trade Date	16-Nov-07	Swaps							
68	Hedge 28	Trade Date	16-Nov-07	Swaps							
69	Hedge 29	Trade Date	7-Dec-07	Swaps							
70	Hedge 30	Trade Date	7-Dec-07	Swaps							
71	Hedge 31	Trade Date	21-Dec-07	Swaps							
72	Hedge 32	Trade Date	21-Dec-07	Swaps							
73	Hedge 33	Trade Date	11-Jan-08	Swaps							
74	Hedge 34	Trade Date	11-Jan-08	Swaps							
75	Hedge 35	Trade Date	25-Jan-08	Swaps							
76	Hedge 36	Trade Date	25-Jan-08	Swaps							
77	Hedge 37	Trade Date	11-Feb-08	Swaps							
78	Hedge 38	Trade Date	11-Feb-08	Swaps							
79	Hedge 39	Trade Date	22-Feb-08	Swaps							
80	Hedge 40	Trade Date	22-Feb-08	Swaps							
81	Hedge 41	Trade Date	7-Mar-08	Swaps							
82	Hedge 42	Trade Date	7-Mar-08	Swaps							
83	Hedge 43	Trade Date	20-Mar-08	Swaps							
84	Hedge 44	Trade Date	20-Mar-08	Swaps							
85	Hedge 45	Trade Date	4-Apr-08	Swaps							
86	Hedge 46	Trade Date	4-Apr-08	Swaps							
87	Hedge 47	Trade Date	18-Apr-08	Swaps							
88	Hedge 48	Trade Date	2-May-08	Swaps							
89	Hedge 49	Trade Date	2-May-08	Swaps							
90	Hedge 50	Trade Date	16-May-08	Swaps							
91	Hedge 51	Trade Date	16-May-08	Swaps							
92	Hedge 52	Trade Date	6-Jun-08	Swaps							
93	Hedge 53	Trade Date	6-Jun-08	Swaps							
94	Hedge 54	Trade Date	20-Jun-08	Swaps							
95	Hedge 55	Trade Date	20-Jun-08	Swaps							
96	Hedge 56	Trade Date	11-Jul-08	Swaps							
97	Hedge 57	Trade Date	25-Jul-08	Swaps							
98	Hedge 58	Trade Date	8-Aug-08	Swaps							
99											
100	Subtotal Hedge Volumes				560,000	895,000	990,000	950,000	695,000	630,000	4,720,000
101	Remaining				40,000	60,000	90,000	70,000	60,000	30,000	350,000
102	Total Volumes				600,000	955,000	1,080,000	1,020,000	755,000	660,000	5,070,000
103											

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line											
5											Peak
6	For Month of:			Reference	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Strip Average
7		(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
104	Strike Price										Weighted Avera
105	Hedge 1	Trade Date	4-May-07	Swaps							
106	Hedge 2	Trade Date	4-May-07	Swaps							
107	Hedge 3	Trade Date	18-May-07	Swaps							
108	Hedge 4	Trade Date	18-May-07	Swaps							
109	Hedge 5	Trade Date	8-Jun-07	Swaps							
110	Hedge 6	Trade Date	8-Jun-07	Swaps							
111	Hedge 7	Trade Date	22-Jun-07	Swaps							
112	Hedge 8	Trade Date	22-Jun-07	Swaps							
113	Hedge 9	Trade Date	9-Jul-07	Swaps							
114	Hedge 10	Trade Date	9-Jul-07	Swaps							
115	Hedge 11	Trade Date	20-Jul-07	Swaps							
116	Hedge 12	Trade Date	20-Jul-07	Swaps							
117	Hedge 13	Trade Date	3-Aug-07	Swaps							
118	Hedge 14	Trade Date	3-Aug-07	Swaps							
119	Hedge 15	Trade Date	17-Aug-07	Swaps							
120	Hedge 16	Trade Date	17-Aug-07	Swaps							
121	Hedge 17	Trade Date	7-Sep-07	Swaps							
122	Hedge 18	Trade Date	7-Sep-07	Swaps							
123	Hedge 19	Trade Date	21-Sep-07	Swaps							
124	Hedge 20	Trade Date	21-Sep-07	Swaps							
125	Hedge 21	Trade Date	5-Oct-07	Swaps							
126	Hedge 22	Trade Date	5-Oct-07	Swaps							
127	Hedge 23	Trade Date	19-Oct-07	Swaps							
128	Hedge 24	Trade Date	19-Oct-07	Swaps							
129	Hedge 25	Trade Date	2-Nov-07	Swaps							
130	Hedge 26	Trade Date	2-Nov-07	Swaps							
131	Hedge 27	Trade Date	16-Nov-07	Swaps							
132	Hedge 28	Trade Date	16-Nov-07	Swaps							
133	Hedge 29	Trade Date	7-Dec-07	Swaps							
134	Hedge 30	Trade Date	7-Dec-07	Swaps							
135	Hedge 31	Trade Date	21-Dec-07	Swaps							
136	Hedge 32	Trade Date	21-Dec-07	Swaps							
137	Hedge 33	Trade Date	11-Jan-08	Swaps							
138	Hedge 34	Trade Date	11-Jan-08	Swaps							
139	Hedge 35	Trade Date	25-Jan-08	Swaps							
140	Hedge 36	Trade Date	25-Jan-08	Swaps							
141	Hedge 37	Trade Date	11-Feb-08	Swaps							
142	Hedge 38	Trade Date	11-Feb-08	Swaps							
143	Hedge 39	Trade Date	22-Feb-08	Swaps							
144	Hedge 40	Trade Date	22-Feb-08	Swaps							
145	Hedge 41	Trade Date	7-Mar-08	Swaps							
146	Hedge 42	Trade Date	7-Mar-08	Swaps							
147	Hedge 43	Trade Date	20-Mar-08	Swaps							
148	Hedge 44	Trade Date	20-Mar-08	Swaps							
149	Hedge 45	Trade Date	4-Apr-08	Swaps							
150	Hedge 46	Trade Date	4-Apr-08	Swaps							
151	Hedge 47	Trade Date	18-Apr-08	Swaps							
152	Hedge 48	Trade Date	2-May-08	Swaps							
153	Hedge 49	Trade Date	2-May-08	Swaps							
154	Hedge 50	Trade Date	16-May-08	Swaps							
155	Hedge 51	Trade Date	16-May-08	Swaps							
156	Hedge 52	Trade Date	6-Jun-08	Swaps							
157	Hedge 53	Trade Date	6-Jun-08	Swaps							
158	Hedge 54	Trade Date	20-Jun-08	Swaps							
159	Hedge 55	Trade Date	20-Jun-08	Swaps							
160	Hedge 56	Trade Date	11-Jul-08	Swaps							
161	Hedge 57	Trade Date	25-Jul-08	Swaps							
162	Hedge 58	Trade Date	8-Aug-08	Swaps							
163											
164	Subtotal Weigthed Average Hedge Prices				$9.4973	$9.8193	$10.0823	$10.0385	$9.8591	$8.6528	9.7305
165	NYMEX				$8.7687	$9.1711	$9.4089	$9.4295	$9.2729	$8.8367	9.2267
166											
167							THIS PAGE HAS BEEN REDACTED				

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line					Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Strip Average
5											
6	For Month of:			Reference							
7	(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
168	Hedge Dollars										
169	Hedge 1	Trade Date	4-May-07	Swaps							
170	Hedge 2	Trade Date	4-May-07	Swaps							
171	Hedge 3	Trade Date	18-May-07	Swaps							
172	Hedge 4	Trade Date	18-May-07	Swaps							
173	Hedge 5	Trade Date	8-Jun-07	Swaps							
174	Hedge 6	Trade Date	8-Jun-07	Swaps							
175	Hedge 7	Trade Date	22-Jun-07	Swaps							
176	Hedge 8	Trade Date	22-Jun-07	Swaps							
177	Hedge 9	Trade Date	9-Jul-07	Swaps							
178	Hedge 10	Trade Date	9-Jul-07	Swaps							
179	Hedge 11	Trade Date	20-Jul-07	Swaps							
180	Hedge 12	Trade Date	20-Jul-07	Swaps							
181	Hedge 13	Trade Date	3-Aug-07	Swaps							
182	Hedge 14	Trade Date	3-Aug-07	Swaps							
183	Hedge 15	Trade Date	17-Aug-07	Swaps							
184	Hedge 16	Trade Date	17-Aug-07	Swaps							
185	Hedge 17	Trade Date	7-Sep-07	Swaps							
186	Hedge 18	Trade Date	7-Sep-07	Swaps							
187	Hedge 19	Trade Date	21-Sep-07	Swaps							
188	Hedge 20	Trade Date	21-Sep-07	Swaps							
189	Hedge 21	Trade Date	5-Oct-07	Swaps							
190	Hedge 22	Trade Date	5-Oct-07	Swaps							
191	Hedge 23	Trade Date	19-Oct-07	Swaps							
192	Hedge 24	Trade Date	19-Oct-07	Swaps							
193	Hedge 25	Trade Date	2-Nov-07	Swaps							
194	Hedge 26	Trade Date	2-Nov-07	Swaps							
195	Hedge 27	Trade Date	16-Nov-07	Swaps							
196	Hedge 28	Trade Date	16-Nov-07	Swaps							
197	Hedge 29	Trade Date	7-Dec-07	Swaps							
198	Hedge 30	Trade Date	7-Dec-07	Swaps							
199	Hedge 31	Trade Date	21-Dec-07	Swaps							
200	Hedge 32	Trade Date	21-Dec-07	Swaps							
201	Hedge 33	Trade Date	11-Jan-08	Swaps							
202	Hedge 34	Trade Date	11-Jan-08	Swaps							
203	Hedge 35	Trade Date	25-Jan-08	Swaps							
204	Hedge 36	Trade Date	25-Jan-08	Swaps							
205	Hedge 37	Trade Date	11-Feb-08	Swaps							
206	Hedge 38	Trade Date	11-Feb-08	Swaps							
207	Hedge 39	Trade Date	22-Feb-08	Swaps							
208	Hedge 40	Trade Date	22-Feb-08	Swaps							
209	Hedge 41	Trade Date	7-Mar-08	Swaps							
210	Hedge 42	Trade Date	7-Mar-08	Swaps							
211	Hedge 43	Trade Date	20-Mar-08	Swaps							
212	Hedge 44	Trade Date	20-Mar-08	Swaps							
213	Hedge 45	Trade Date	4-Apr-08	Swaps							
214	Hedge 46	Trade Date	4-Apr-08	Swaps							
215	Hedge 47	Trade Date	18-Apr-08	Swaps							
216	Hedge 48	Trade Date	2-May-08	Swaps							
217	Hedge 49	Trade Date	2-May-08	Swaps							
218	Hedge 50	Trade Date	16-May-08	Swaps							
219	Hedge 51	Trade Date	16-May-08	Swaps							
220	Hedge 52	Trade Date	6-Jun-08	Swaps							
221	Hedge 53	Trade Date	6-Jun-08	Swaps							
222	Hedge 54	Trade Date	20-Jun-08	Swaps							
223	Hedge 55	Trade Date	20-Jun-08	Swaps							
224	Hedge 56	Trade Date	11-Jul-08	Swaps							
225	Hedge 57	Trade Date	25-Jul-08	Swaps							
226	Hedge 58	Trade Date	8-Aug-08	Swaps							
227											
228	Subtotal Hedge Dollars				$5,318,489	$8,788,281	$9,981,478	$9,536,590	$6,852,071	$5,451,250	$45,928,159
229	Remaining				350,747	550,268	846,798	660,067	556,372	265,100	3,229,352
230											
231	Target Hedged Dollars				$5,669,236	$9,338,549	$10,828,276	$10,196,657	$7,408,443	$5,716,350	$49,157,511
232											
233	Weighted Average Hedged Cost per Unit				$9.4487	$9.7786	$10.0262	$9.9967	$9.8125	$8.6611	$9.6958

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 07 - Apr 08 vs Nov 08 - Apr 09 - Residential Heating Rate R-3

November 1, 2008 - April 30, 2009 / **May 1, 2008 - October 31, 2008**
Residential Heating (R3)

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter:																
Cust. Chg	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$68.76								
Headblock	$0.3356	$33.56	$33.56	$33.56	$33.56	$33.56	$33.56	$201.36								
Tailblock	$0.1950	$1.76	$9.75	$16.97	$17.16	$12.87	$6.24	$64.74								
HB Threshold	100															
Summer:																
Cust. Chg	$11.46								$9.88	$9.88	$9.88	$10.25	$11.46	$11.46	$62.81	$131.57
Headblock	$0.3356								$5.89	$5.89	$5.89	$6.08	$6.71	$6.71	$37.18	$238.54
Tailblock	$0.1950								$11.98	$5.99	$1.71	$1.77	$4.29	$9.95	$35.68	$100.42
HB Threshold	20															
Total Base Rate Amount		$46.78	$54.77	$61.99	$62.18	$57.89	$51.26	$334.86	$27.75	$21.76	$17.48	$18.10	$22.46	$28.12	$135.66	$470.52
CGA Rate - (Seasonal)		$1.2635	$1.2635	$1.2635	$1.2635	$1.2635	$1.2635	$1.2635	$1.1870	$1.3902	$1.4244	$1.4628	$1.1702	$1.1702	$1.2646	$1.2638
CGA amount		$137.72	$189.53	$236.27	$237.54	$209.74	$166.78	$1,177.58	$106.83	$76.46	$42.73	$43.88	$49.15	$83.08	$402.14	$1,579.72
LDAC		$0.0265	$0.0265	$0.0265	$0.0265	$0.0265	$0.0265	0.0265	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0246
LDAC amount		$2.89	$3.98	$4.96	$4.98	$4.40	$3.50	$24.70	$1.73	$1.06	$0.58	$0.58	$0.81	$1.36	$6.11	$30.80
Total Bill		**$187.39**	**$248.27**	**$303.22**	**$304.70**	**$272.03**	**$221.54**	**$1,537.14**	**$136.31**	**$99.28**	**$60.79**	**$62.56**	**$72.42**	**$112.56**	**$543.91**	**$2,081.05**

NOVEMBER 1, 2007 - April 31, 2008 / **May 1, 2007 - October 31, 2007**
Residential Heating (R3)

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Winter Nov-Apr	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter:																
Cust. Chg	$9.88	$9.88	$9.88	$9.88	$9.88	$9.88	$9.88	$59.28								
Headblock	$0.2945	29.45	29.45	29.45	29.45	29.45	29.45	$176.70								
Tailblock	$0.1711	$1.54	$8.56	$14.89	$15.06	$11.29	$5.48	$56.81								
HB Threshold	100															
Summer:																
Cust. Chg	$9.88								$9.88	$9.88	$9.88	$9.88	$9.88	$9.88	$59.28	$118.56
Headblock	$0.2945								$5.89	$5.89	$5.89	$5.89	$5.89	$5.89	$35.34	$212.04
Tailblock	$0.1711								$11.98	$5.99	$1.71	$1.71	$3.76	$8.73	$33.88	$90.68
HB Threshold	20															
Total Base Rate Amount		$40.87	$47.89	$54.22	$54.39	$50.62	$44.81	$292.79	$27.75	$21.76	$17.48	$17.48	$19.53	$24.50	$128.50	$421.28
CGA Rate - (Seasonal)		$1.1843	$1.1666	$1.1325	$1.1478	$1.1700	$1.2792	$1.1746	$1.0388	$1.0775	$1.0352	$0.8972	$0.8522	$0.9057	$0.9774	$1.1244
CGA amount		$129.09	$174.99	$211.78	$215.79	$194.22	$168.85	$1,094.72	$93.49	$59.26	$31.06	$26.92	$35.79	$64.30	$310.82	$1,405.54
LDAC		$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	0.0192	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0243
LDAC amount		$2.09	$2.88	$3.59	$3.61	$3.19	$2.53	$17.89	$3.55	$2.17	$1.18	$1.18	$1.65	$2.80	$12.53	$30.42
Total Bill		**$172.05**	**$225.76**	**$269.58**	**$273.78**	**$248.03**	**$216.19**	**$1,405.40**	**$124.79**	**$83.19**	**$49.72**	**$45.58**	**$56.98**	**$91.60**	**$451.85**	**$1,857.25**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$15.33**	**$22.52**	**$33.63**	**$30.92**	**$24.00**	**$5.35**	**$131.74**	**$11.52**	**$16.09**	**$11.07**	**$16.98**	**$15.44**	**$20.97**	**$92.06**	**$223.80**
% Change	**8.91%**	**9.97%**	**12.48%**	**11.29%**	**9.68%**	**2.47%**	**9.37%**	**9.23%**	**19.34%**	**22.27%**	**37.25%**	**27.09%**	**22.89%**	**20.37%**	**12.05%**
Base Rate	$5.91	$6.89	$7.77	$7.79	$7.27	$6.45	$42.07	$0.00	$0.00	$0.00	$0.62	$2.93	$3.62	$7.16	$49.24
% Change	14.45%	14.38%	14.33%	14.33%	14.36%	14.41%	14.37%	0.00%	0.00%	0.00%	3.53%	14.99%	14.78%	5.58%	11.69%
CGA & LDAC	$9.43	$15.63	$25.86	$23.12	$16.73	($1.11)	$89.67	$11.52	$16.09	$11.07	$16.36	$12.51	$17.35	$84.89	$174.56
% Change	7.30%	8.93%	12.21%	10.72%	8.62%	-0.66%	8.19%	12.32%	27.15%	35.65%	60.79%	34.94%	26.97%	27.31%	12.42%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 07 - Apr 08 vs Nov 08 - Apr 09 - Commercial Rate G-41

November 1, 2008 - April 30, 2009
Commercial Rate (G-41)

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr
Typical Usage (Therms)		193	269	298	262	234	171	1,427
Winter:								
Cust. Chg	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$171.48
Headblock	$0.3732	$37.32	$37.32	$37.32	$37.32	$37.32	$37.32	$223.92
Tailblock	$0.2427	$22.57	$41.02	$48.05	$39.32	$32.52	$17.23	$200.71
HB Threshold	100							
Summer:								
Cust. Chg	$28.58							
Headblock	$0.3732							
Tailblock	$0.2427							
HB Threshold	20							
Total Base Rate Amount		$88.47	$106.92	$113.95	$105.22	$98.42	$83.13	$596.11
CGA Rate - (Seasonal)		$1.2636	$1.2636	$1.2636	$1.2636	$1.2636	$1.2636	$1.2636
CGA amount		$243.87	$339.91	$376.55	$331.06	$295.68	$216.08	$1,803.16
LDAC		$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	0.0288
LDAC amount		$5.56	$7.75	$8.58	$7.55	$6.74	$4.92	$41.10
Total Bill		**$337.90**	**$454.57**	**$499.09**	**$443.83**	**$400.84**	**$304.13**	**$2,440.37**

May 1, 2008 - October 31, 2008

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	117	81	72	72	89	142	573	2,000
Cust. Chg	$24.64	$24.64	$24.64	$25.56	$28.58	$28.58	$156.64	$328.12
Headblock	$6.55	$6.55	$6.55	$6.76	$7.46	$7.46	$41.34	$265.26
Tailblock	$20.66	$12.99	$11.08	$11.44	$16.75	$29.61	$102.52	$303.23
Total Base Rate Amount	$51.85	$44.18	$42.27	$43.76	$52.79	$65.65	$300.50	$896.62
CGA Rate - (Seasonal)	$1.1874	$1.3906	$1.4249	$1.4633	$1.1706	$1.1706	$1.2739	$1.2665
CGA amount	$138.93	$112.64	$102.59	$105.36	$104.18	$166.23	$729.92	$2,533.08
LDAC	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0234
LDAC amount	$1.18	$0.82	$0.73	$0.73	$0.90	$1.43	$5.79	$46.88
Total Bill	**$191.96**	**$157.64**	**$145.59**	**$149.84**	**$157.87**	**$233.31**	**$1,036.21**	**$3,476.58**

NOVEMBER 1, 2007 - April 31, 2008
Commercial Rate (G-41)

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Winter Nov-Apr
Typical Usage (Therms)		193	269	298	262	234	171	1,427
Winter:								
Cust. Chg	$24.64	$24.64	$24.64	$24.64	$24.64	$24.64	$24.64	$147.84
Headblock	$0.3275	32.75	32.75	32.75	32.75	32.75	32.75	$196.50
Tailblock	$0.2130	$19.81	$36.00	$42.17	$34.51	$28.54	$15.12	$176.15
HB Threshold	100							
Summer:								
Cust. Chg	$24.64							
Headblock	$0.3275							
Tailblock	$0.2130							
HB Threshold	20							
Total Base Rate Amount		$77.20	$93.39	$99.56	$91.90	$85.93	$72.51	$520.49
CGA Rate - (Seasonal)		$1.1844	$1.1667	$1.1326	$1.1479	$1.1701	$1.2793	$1.1726
CGA amount		$228.59	$313.84	$337.51	$300.75	$273.80	$218.76	$1,673.26
LDAC		$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	0.0101
LDAC amount		$1.95	$2.72	$3.01	$2.65	$2.36	$1.73	$14.41
Total Bill		**$307.74**	**$409.95**	**$440.09**	**$395.29**	**$362.10**	**$293.00**	**$2,208.16**

May 1, 2007 - October 31, 2007

	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	117	81	72	72	89	142	573	2,000
Cust. Chg	$24.64	$24.64	$24.64	$24.64	$24.64	$24.64	$147.84	$295.68
Headblock	$6.55	$6.55	$6.55	$6.55	$6.55	$6.55	$39.30	$235.80
Tailblock	$20.66	$12.99	$11.08	$11.08	$14.70	$25.99	$96.49	$272.64
Total Base Rate Amount	$51.85	$44.18	$42.27	$42.27	$45.89	$57.18	$283.63	$804.12
CGA Rate - (Seasonal)	$1.0409	$1.0796	$1.0373	$0.8993	$0.8543	$0.9078	$0.9662	$1.1134
CGA amount	$121.79	$87.45	$74.69	$64.75	$76.03	$128.91	$553.61	$2,226.87
LDAC	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0170
LDAC amount	$4.00	$2.77	$2.46	$2.46	$3.04	$4.86	$19.60	$34.01
Total Bill	**$177.64**	**$134.40**	**$119.41**	**$109.48**	**$124.96**	**$190.94**	**$856.83**	**$3,065.00**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$30.17**	**$44.63**	**$59.00**	**$48.53**	**$38.74**	**$11.13**	**$232.20**	**$14.32**	**$23.24**	**$26.17**	**$40.37**	**$32.91**	**$42.37**	**$179.38**	**$411.58**
% Change	**9.80%**	**10.89%**	**13.41%**	**12.28%**	**10.70%**	**3.80%**	**10.52%**	**8.06%**	**17.29%**	**21.92%**	**36.87%**	**26.33%**	**22.19%**	**20.94%**	**13.43%**
Base Rate	$11.27	$13.53	$14.39	$13.32	$12.49	$10.62	$75.62	$0.00	$0.00	$0.00	$1.49	$6.90	$8.48	$16.87	$92.50
% Change	14.60%	14.49%	14.45%	14.50%	14.53%	14.64%	14.53%	0.00%	0.00%	0.00%	3.53%	15.04%	14.83%	5.95%	11.50%
CGA & LDAC	$18.89	$31.10	$44.61	$35.21	$26.25	$0.51	$156.58	$14.32	$23.24	$26.17	$38.87	$26.01	$33.90	$162.51	$319.09
% Change	8.27%	9.91%	13.22%	11.71%	9.59%	0.23%	9.36%	11.76%	26.57%	35.04%	60.04%	34.20%	26.29%	29.35%	14.33%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 07 - Apr 08 vs Nov 08 - Apr 09 - Commercial Rate G-42

November 1, 2008 - April 30, 2009 — **May 1, 2008 - October 31, 2008**
C&I High Winter Use Medium G-42

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
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:																
Cust. Chg	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$482.64								
Headblock	$0.3095	$309.50	$309.50	$309.50	$309.50	$309.50	$309.50	$1,857.00								
Tailblock	$0.2044	$113.03	$322.54	$462.97	$634.25	$490.97	$301.08	$2,324.85								
HB Threshold	1,000															
Summer:																
Cust. Chg	$80.44								$69.36	$69.36	$69.36	$71.95	$80.44	$80.44	$440.91	$923.55
Headblock	$0.3095								$108.64	$108.64	$108.64	$59.73	$112.66	$123.80	$622.11	$2,479.11
Tailblock	$0.2044								$153.93	$54.00	$2.51	$0.00	$0.00	$61.12	$271.55	$2,596.40
HB Threshold	400															
Total Base Rate Amount		$502.97	$712.48	$852.91	$1,024.19	$880.91	$691.02	$4,664.49	$331.93	$232.00	$180.51	$131.68	$193.10	$265.36	$1,334.57	$5,999.06
CGA Rate - (Seasonal)		$1.2636	$1.2636	$1.2636	$1.2636	$1.2636	$1.2636	$1.2636	$1.1874	$1.3906	$1.4249	$1.4633	$1.1706	$1.1706	$1.2646	$1.2638
CGA amount		$1,962.37	$3,257.56	$4,125.65	$5,184.55	$4,298.77	$3,124.88	$21,953.79	$1,493.75	$974.81	$589.91	$311.68	$426.10	$818.25	$4,614.50	$26,568.29
LDAC		$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	0.0288	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0256
LDAC amount		$44.73	$74.25	$94.03	$118.17	$97.98	$71.22	$500.37	$12.71	$7.08	$4.18	$2.15	$3.68	$7.06	$36.85	$537.23
Total Bill		**$2,510.07**	**$4,044.29**	**$5,072.59**	**$6,326.91**	**$5,277.65**	**$3,887.13**	**$27,118.64**	**$1,838.38**	**$1,213.89**	**$774.60**	**$445.51**	**$622.87**	**$1,090.66**	**$5,985.92**	**$33,104.57**

NOVEMBER 1, 2007 - April 31, 2008 — **May 1, 2007 - October 31, 2007**
C&I High Winter Use Medium G-42

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Winter Nov-Apr	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Summer May-Oct	Total Nov-Oct
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:																
Cust. Chg	$69.36	$69.36	$69.36	$69.36	$69.36	$69.36	$69.36	$416.16								
Headblock	$0.2716	271.60	271.60	271.60	271.60	271.60	271.60	$1,629.60								
Tailblock	$0.1794	$99.21	$283.09	$406.34	$556.68	$430.92	$264.26	$2,040.50								
HB Threshold	1,000															
Summer:																
Cust. Chg	$69.36								$69.36	$69.36	$69.36	$69.36	$69.36	$69.36	$416.16	$832.32
Headblock	$0.2716								$108.64	$108.64	$108.64	$57.85	$98.86	$108.64	$591.27	$2,220.87
Tailblock	$0.1794								$153.93	$54.00	$2.51	$0.00	$0.00	$53.64	$264.08	$2,304.57
HB Threshold	400															
Total Base Rate Amount		$440.17	$624.05	$747.30	$897.64	$771.88	$605.22	$4,086.26	$331.93	$232.00	$180.51	$127.21	$168.22	$231.64	$1,271.51	$5,357.77
CGA Rate - (Seasonal)		$1.1844	$1.1667	$1.1326	$1.1479	$1.1701	$1.2793	$1.1741	$1.0409	$1.0796	$1.0373	$0.8993	$0.8543	$0.9078	$0.9956	$1.1431
CGA amount		$1,839.37	$3,007.75	$3,697.94	$4,709.83	$3,980.68	$3,163.71	$20,399.29	$1,309.45	$756.80	$429.44	$191.55	$310.97	$634.55	$3,632.76	$24,032.05
LDAC		$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	0.0101	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0143
LDAC amount		$15.69	$26.04	$32.98	$41.44	$34.36	$24.98	$175.48	$43.02	$23.97	$14.16	$7.28	$12.45	$23.91	$124.80	$300.27
Total Bill		**$2,295.23**	**$3,657.84**	**$4,478.22**	**$5,648.91**	**$4,786.92**	**$3,793.90**	**$24,661.02**	**$1,684.40**	**$1,012.77**	**$624.11**	**$326.05**	**$491.64**	**$890.10**	**$5,029.07**	**$29,690.09**

DIFFERENCE:

Total Bill	**$214.84**	**$386.45**	**$594.38**	**$678.00**	**$490.73**	**$93.22**	**$2,457.62**	**$153.98**	**$201.12**	**$150.49**	**$119.47**	**$131.24**	**$200.57**	**$956.86**	**$3,414.48**
% Change	**9.36%**	**10.56%**	**13.27%**	**12.00%**	**10.25%**	**2.46%**	**9.97%**	**9.14%**	**19.86%**	**24.11%**	**36.64%**	**26.69%**	**22.53%**	**19.03%**	**11.50%**
Base Rate	$62.80	$88.43	$105.61	$126.56	$109.03	$85.80	$578.23	$0.00	$0.00	$0.00	$4.47	$24.88	$33.72	$63.06	$641.29
% Change	14.27%	14.17%	14.13%	14.10%	14.13%	14.18%	14.15%	0.00%	0.00%	0.00%	3.51%	14.79%	14.55%	4.96%	11.97%
CGA & LDAC	$152.04	$298.02	$488.77	$551.44	$381.70	$7.42	$1,879.39	$153.98	$201.12	$150.49	$115.00	$106.36	$166.85	$893.80	$2,773.19
% Change	8.27%	9.91%	13.22%	11.71%	9.59%	0.23%	9.21%	11.76%	26.57%	35.04%	60.04%	34.20%	26.29%	24.60%	11.54%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 07 - Apr 08 vs Nov 08 - Apr 09 - Commercial Rate G-52

November 1, 2008 - April 30, 2009 / **May 1, 2008 - October 31, 2008**
Commercial Rate (G-52)

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
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:																
Cust. Chg	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$482.16								
Headblock	$0.1976	$197.60	$197.60	$197.60	$197.60	$197.60	$197.60	$1,185.60								
Tailblock	$0.1341	$96.82	$145.63	$178.35	$178.76	$173.12	$116.94	$889.62								
HB Threshold	1,000															
Summer:																
Cust. Chg	$80.36								$69.29	$69.29	$69.29	$71.87	$80.36	$80.36	$440.46	$922.62
Headblock	$0.1453								$127.50	$127.50	$127.50	$131.65	$145.30	$145.30	$804.75	$1,990.35
Tailblock	$0.0836								$37.43	$27.45	$18.13	$14.40	$17.56	$27.09	$142.06	$1,031.68
HB Threshold	1,000															
Total Base Rate Amount		$374.78	$423.59	$456.31	$456.72	$451.08	$394.90	$2,557.38	$234.22	$224.24	$214.92	$217.92	$243.22	$252.75	$1,387.27	$3,944.65
CGA Rate - (Seasonal)		$1.2630	$1.2630	$1.2630	$1.2630	$1.2630	$1.2630	$1.2630	$1.1867	$1.3899	$1.4240	$1.4624	$1.1700	$1.1700	$1.2963	$1.2758
CGA amount		$2,174.89	$2,634.62	$2,942.79	$2,946.58	$2,893.53	$2,364.34	$15,956.74	$1,791.92	$1,909.72	$1,775.73	$1,740.26	$1,415.70	$1,549.08	$10,182.40	$26,139.15
LDAC		$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	0.0288	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0216
LDAC amount		$49.59	$60.08	$67.10	$67.19	$65.98	$53.91	$363.86	$15.25	$13.88	$12.59	$12.02	$12.22	$13.37	$79.34	$443.19
Total Bill		**$2,599.26**	**$3,118.29**	**$3,466.21**	**$3,470.48**	**$3,410.60**	**$2,813.14**	**$18,877.98**	**$2,041.39**	**$2,147.84**	**$2,003.24**	**$1,970.20**	**$1,671.14**	**$1,815.20**	**$11,649.01**	**$30,526.99**

NOVEMBER 1, 2007 - April 31, 2008 / **May 1, 2007 - October 31, 2007**
Commercial Rate (G-52)

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Winter Nov-Apr	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Summer May-Oct	Total Nov-Oct
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:																
Cust. Chg	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$415.74								
Headblock	$0.1734	173.40	173.40	173.40	173.40	173.40	173.40	$1,040.40								
Tailblock	$0.1177	$84.98	$127.82	$156.54	$156.89	$151.95	$102.63	$780.82								
HB Threshold	1,000															
Summer:																
Cust. Chg	$69.29								$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$415.74	$831.48
Headblock	$0.1275								$127.50	$127.50	$127.50	$127.50	$127.50	$127.50	$765.00	$1,805.40
Tailblock	$0.0734								$37.43	$27.45	$18.13	$13.95	$15.41	$23.78	$136.16	$916.98
HB Threshold	1,000															
Total Base Rate Amount		$327.67	$370.51	$399.23	$399.58	$394.64	$345.32	$2,236.96	$234.22	$224.24	$214.92	$210.74	$212.20	$220.57	$1,316.90	$3,553.86
CGA Rate - (Seasonal)		$1.1838	$1.1661	$1.1320	$1.1473	$1.1695	$1.2787	$1.1761	$1.0370	$1.0757	$1.0334	$0.8954	$0.8504	$0.9039	$0.9706	$1.0973
CGA amount		$2,038.50	$2,432.48	$2,637.56	$2,676.65	$2,679.32	$2,393.73	$14,858.25	$1,565.87	$1,478.01	$1,288.65	$1,065.53	$1,028.98	$1,196.76	$7,623.81	$22,482.06
LDAC		$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	0.0101	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0342	$0.0193
LDAC amount		$17.39	$21.07	$23.53	$23.56	$23.14	$18.91	$127.60	$51.64	$46.99	$42.65	$40.70	$41.38	$45.28	$268.64	$396.24
Total Bill		**$2,383.57**	**$2,824.07**	**$3,060.32**	**$3,099.80**	**$3,097.10**	**$2,757.96**	**$17,222.82**	**$1,851.74**	**$1,749.24**	**$1,546.22**	**$1,316.96**	**$1,282.57**	**$1,462.62**	**$9,209.34**	**$26,432.16**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$215.69**	**$294.22**	**$405.88**	**$370.69**	**$313.49**	**$55.19**	**$1,655.17**	**$189.66**	**$398.60**	**$457.03**	**$653.24**	**$388.57**	**$352.58**	**$2,439.67**	**$4,094.83**
% Change	**9.05%**	**10.42%**	**13.26%**	**11.96%**	**10.12%**	**2.00%**	**9.61%**	**10.24%**	**22.79%**	**29.56%**	**49.60%**	**30.30%**	**24.11%**	**26.49%**	**15.49%**
Base Rate	$47.11	$53.08	$57.08	$57.13	$56.44	$49.57	$320.42	$0.00	$0.00	$0.00	$7.19	$31.01	$32.17	$70.38	$390.79
% Change	14.38%	14.33%	14.30%	14.30%	14.30%	14.35%	14.32%	0.00%	0.00%	0.00%	3.41%	14.61%	14.59%	5.34%	11.00%
CGA & LDAC	$168.58	$241.14	$348.80	$313.56	$257.05	$5.62	$1,334.75	$189.66	$398.60	$457.03	$646.05	$357.56	$320.41	$2,369.29	$3,704.04
% Change	8.27%	9.91%	13.22%	11.71%	9.59%	0.23%	8.98%	12.11%	26.97%	35.47%	60.63%	34.75%	26.77%	31.08%	16.48%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Residential Heating

	Winter 2007-08	Winter 2008-09
Customer Charge	$9.88	$11.46
First 100 Therms	$0.2945	$0.3356
Excess 100 Therms	$0.1711	$0.1950
LDAC	$0.0192	$0.0265
CGA	$1.1746	$1.2635
Total Adjust	$1.1938	$1.2900

		Winter 2007-08 CGA @	Winter 2008-09 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Im	$ Impact	% Impact	$ Impact	% Impact
		$1.1938	$1.2900	$0.10	8%						
Cooking alone	5	$17.32	$19.59	$2.27	13%	$1.79	10%	$0.44	2%	$0.04	0%
	10	$24.76	$27.72	$2.95	12%	$1.99	8%	$0.89	3%	$0.07	0%
	20	$39.65	$43.97	$4.33	11%	$2.40	6%	$1.78	4%	$0.15	0%
Water Heating alone	30	$54.53	$60.23	$5.70	10%	$2.81	5%	$2.67	4%	$0.22	0%
	45	$76.85	$84.61	$7.76	10%	$3.43	4%	$4.00	5%	$0.33	0%
	50	$84.29	$92.74	$8.45	10%	$3.64	4%	$4.45	5%	$0.37	0%
Heating Alone	80	$121.50	$133.38	$11.88	10%	$4.66	4%	$6.67	5%	$0.55	0%
	125	$203.75	$223.03	$19.27	9%	$6.48	3%	$11.83	5%	$0.97	0%
	150	$226.95	$248.27	$21.32	9%	$6.89	3%	$13.34	5%	$1.10	0%
	200	$295.20	$322.52	$27.32	9%	$8.08	3%	$17.78	6%	$1.46	0%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Variance Analysis of the Components of the 2007-08 Actual Results vs Proposed Winter 2008-09 Cost of Gas Rate

	WINTER SALES ACTUAL RESULTS (6 months actual)			**WINTER 2008-09 (6 months Proposed)**		
Therm Sales	88,842,320			90,372,901		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 9,298,378	$ 0.1047		$ 7,672,333	$ 0.0849
Purchased Gas	82,068,370	73,752,813	0.8302	74,042,944	79,707,811	0.8820
Storage Gas	11,798,560	9,050,229	0.1019	19,065,117	16,341,221	0.1808
Produced Gas	806,300	1,072,942	0.0121	2,260,757	2,665,995	0.0295
Hedging (Gain)/Loss		7,634,496	$ 0.0859		2,524,964	0.0279
Total Volumes and Cost	94,673,230	$ 100,808,858	$ 1.1347	95,368,818	$ 108,912,324	$ 1.2051
Prior Period Balance		$ 756,088	$ 0.0085		2,883,321	$ 0.0319
Interest		408,585	0.0046		336,795	0.0037
Prior Period Adjustment		17,994	0.0002		-	0.0000
Broker Revenues		(823,538)	(0.0093)		(1,249,699)	(0.0138)
Refunds from Suppliers		-	-		-	-
Fuel Financing		601,417	0.0068		526,256	0.0058
Transportation CGA Revenues		(114,678)	(0.0013)		(5,004)	(0.0001)
280 Day Margin		(23,324)	(0.0003)		-	0.0000
Interruptible Sales Margin		(2,078)	(0.0000)		(2,245)	(0.0000)
Capacity Release and Off System Sales Margins		(379,375)	(0.0043)		(410,806)	(0.0045)
Hedging Costs		-	-		-	-
Other Costs		32,412	0.0004		-	0.0000
FPO Admin Costs		36,312	0.0004		36,312	0.0004
Indirect Gas Costs		4,097,298	0.0461		3,163,335	0.0350
Total Adjusted Cost		$ 105,415,971	**$ 1.1866**		$ 114,190,589	**$ 1.2635**

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Capacity Assignment Calculations 2008-2009
Derivation of Class Assignments and Weightings

Basic assumptions:

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

Line	Description			**Column A**	**Column B**	**Column C**	**Column D**	**Column E**	**Column F**
				Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg			705	771	0.5%		182	589
2	RATE R-3-Resi Htg			61,315	68,577	47.3%		3,933	64,644
3	RATE G-41 (T)			22,129	24,830	17.1%		786	24,044
4	RATE G-51 (S)			2,626	2,880	2.0%		624	2,256
5	RATE G-42 (V)			32,233	36,083	24.9%		1,807	34,276
6	RATE G-52			4,075	4,441	3.1%		1,187	3,254
7	RATE G-43			3,302	3,663	2.5%		446	3,217
8	RATE G-53			1,463	1,616	1.1%		255	1,361
9	RATE G-54			485	493	0.3%		425	68
10	RATE G-63			1,557	1,748	1.2%		51	1,697
11	Total			129,890	145,102	100.0%		9,696	135,406
12									-
13	Residential Total			62,020	69,348	**47.793%**		4,115	65,233
14	LLF Total			57,663	64,576	**44.504%**		3,039	61,537
15	HLF Total			10,207	11,178	**7.704%**		2,543	8,635
16	Total			129,890	145,102	100.0%		9,696	135,406
17									
18	C&I Breakdown								
19	LLF Total							3,039	61,537
20	HLF Total							2,543	8,635
21	Total							5,581	70,173
22									
23	C&I Breakdown Percentage								
24	LLF Total							54.444%	87.694%
25	HLF Total							45.556%	12.306%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$4,993,581	49,718	$8.3698			
30	Storage			$4,012,649	28,115	$11.8936			
31									
32	Peaking			$3,722,262					
33	Peaking Additional Costs (City Gate Deliveries x Differential)			$2,368,452					
34	Subtotal Peaking Costs			$6,090,713	67,267	$7.5454			
35	Total			$15,096,943	145,100	$8.6704			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			973,857	9,696	$8.3698			
39	Pipeline - Remaining			4,019,724	40,022	$8.3699			
40	Storage			4,012,649	28,115	$11.8936			
41	Peaking			6,090,713	67,267	$7.5454			
42	Total			15,096,943	145,100	$8.6704			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**47.793%**	465,436	4,634	$8.3698			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**47.793%**	1,921,158	19,128	$8.3699			
48	Storage	Line 40 * Line 13 Col C	**47.793%**	1,917,772	13,437	$11.8936			
49	Peaking	Line 41 * Line 13 Col C	**47.793%**	2,910,925	32,149	$7.5454			
50	Total		**47.793%**	7,215,271	69,348	$8.6704			

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

Peak 2008 - 2009 Winter Cost of Gas Filing

Capacity Assignment Calculations 2008-2009

Derivation of Class Assignments and Weightings

Line								
51								
52								**Ratios for COG**
53	C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46			508,421	5,062	$8.3698	
55	Pipeline - Remaining	Line 39 - Line 47			2,098,565	20,894	$8.3698	
56	Storage	Line 40 - Line 48			2,094,877	14,678	$11.8935	
57	Peaking	Line 41 - Line 49			3,179,789	35,118	$7.5455	
58	Total			**52.207%**	7,881,653	75,752	$8.6704	**1.0000**
59								
60								
61	LLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E			276,803	2,756	$8.3697	
63	Pipeline - Remaining	Line 55 * Line 24 Col F			1,840,316	18,323	$8.3698	
64	Storage	Line 56 * Line 24 Col F			1,837,082	12,872	$11.8933	
65	Peaking	Line 57 * Line 24 Col F			2,788,484	30,796	$7.5456	
66	Total			**44.6626%**	6,742,685	64,747	$8.6782	**1.0009**
67								(Line 66 / Line 58)
68								
69	HLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62			231,618	2,306	$8.3701	
71	Pipeline - Remaining	Line 55 - Line 63			258,249	2,571	$8.3706	
72	Storage	Line 56 - Line 64			257,795	1,806	$11.8953	
73	Peaking	Line 57 - Line 65			391,305	4,322	$7.5448	
74	Total			**7.5444%**	1,138,967	11,005	$8.6246	**0.9947**
75								(Line 74 / Line 58)
76								
77	Unit Cost				Residential	LLF C&I	HLF C&I	
78								
79	Pipeline				$ 8.3698	$ 8.3698	$ 8.3698	
80	Storage				$ 11.8936	$ 11.8936	$ 11.8936	
81	Peaking				$ -	$ -	$ -	
82	Total				$ 8.6704	$ 8.6782	$ 8.6246	
83								
84								
85	Load Makeup				Residential	**LLF C&I**	**HLF C&I**	
86								
87	Pipeline				34.26%	**32.56%**	**44.32%**	
88	Storage				19.38%	**19.88%**	**16.41%**	
89	Peaking				46.36%	**47.56%**	**39.27%**	
90	Total				100.00%	**100.00%**	**100.00%**	
91								
92								
93	Supply Makeup				Residential	LLF C&I	HLF C&I	Total
94								
95	Pipeline				47.79%	42.40%	9.81%	100.00%
96	Storage				47.79%	45.78%	6.42%	100.00%
97	Peaking				47.79%	45.78%	6.43%	100.00%

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Correction Factor Calculation**

Ln		Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
8	Data Source: Schedule 10B							
11	G-41	1,020,617	2,449,616	3,207,206	3,296,819	2,886,849	2,003,509	14,864,616
12	G-42	1,623,762	3,172,230	4,045,107	4,129,480	3,628,062	2,736,223	19,334,865
13	G-43	146,007	191,262	321,141	323,080	293,860	279,100	1,554,450
14	High Winter Use	2,790,386	5,813,108	7,573,455	7,749,379	6,808,771	5,018,832	35,753,931
16	G-51	249,859	360,815	425,821	436,857	397,040	337,089	2,207,481
17	G-52	382,690	514,335	608,707	634,252	568,906	503,075	3,211,965
18	G-53	72,207	77,155	99,005	108,655	93,345	87,600	537,966
19	G-54	120	96	117	917	2,599	3,785	7,634
20	G-63	2,506	2,842	3,090	2,745	1,226	1,119	13,527
21	Low Winter Use	707,382	955,243	1,136,740	1,183,425	1,063,116	932,668	5,978,574
23	Gross Total	3,497,768	6,768,351	8,710,195	8,932,804	7,871,887	5,951,500	41,732,505

Ln			
26	Total Sales	41,732,505	
27	Low Winter Use	5,978,574	
28	Winter Ratio for Low Winter Use =	**0.99470**	Schedule 10A p 2, ln 74
29	High Winter Use	35,753,931	
30	Winter Ratio for High Winter Use =	**1.00090**	Schedule 10A p 2, ln 66
32	Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))	
33	Correction Factor =	**99.9988%**	

36 **Allocation Calculation for Miscellaneous Overhead**

Ln		Period	Volume	Source
38	Projected Winter Sales Volume	(11/1/07 - 4/30/08)	89,930,543	Sch.10B
39	Projected Annual Sales Volume	(11/1/07 - 10/31/08)	112,874,302	Sch.10B
40	Percentage of Winter to Annual Sales		79.67%	

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **2008 - 2009 Winter Cost of Gas Filing**
5
6

								Subtotal							Subtotal	
7	**Firm Sales**															
8		**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**PK 08-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**OP 09**	**Total**
9	R-1	84,155	120,589	133,683	134,327	122,100	111,185	706,039	94,295	77,110	61,465	53,433	55,105	62,503	403,911	1,109,950
10	R-3	3,921,271	7,918,892	9,187,981	9,352,706	7,861,638	5,920,059	44,162,548	3,253,267	1,871,475	1,257,231	1,117,660	1,208,845	1,611,389	10,319,866	54,482,414
11	R-4	118,081	343,507	533,057	815,918	770,740	748,147	3,329,451	423,521	140,410	90,614	75,795	76,267	100,447	907,054	4,236,505
12	Total Residential.	4,123,508	8,382,988	9,854,722	10,302,951	8,754,478	6,779,391	48,198,038	3,771,083	2,088,995	1,409,310	1,246,888	1,340,217	1,774,338	11,630,831	59,828,869
13																
14	G-41	1,020,617	2,449,616	3,207,206	3,296,819	2,886,849	2,003,509	14,864,616	942,536	408,290	227,683	212,060	249,486	363,847	2,403,902	17,268,518
15	G-42	1,623,762	3,172,230	4,045,107	4,129,480	3,628,062	2,736,223	19,334,865	1,575,097	808,566	509,694	451,021	504,242	782,765	4,631,386	23,966,250
16	G-43	146,007	191,262	321,141	323,080	293,860	279,100	1,554,450	66,756	186,886	116,953	105,099	99,139	149,990	724,824	2,279,274
17	G-51	249,859	360,815	425,821	436,857	397,040	337,089	2,207,481	270,919	225,721	189,301	183,707	184,178	197,294	1,251,120	3,458,601
18	G-52	382,690	514,335	608,707	634,252	568,906	503,075	3,211,965	387,696	341,333	283,480	283,542	299,921	305,823	1,901,795	5,113,760
19	G-53	72,207	77,155	99,005	108,655	93,345	87,600	537,966	54,949	47,322	40,946	38,733	40,941	41,444	264,335	802,300
20	G-54	120	96	117	917	2,599	3,785	7,634	298	287	178	251	202	252	1,467	9,101
21	G-63	2,506	2,842	3,090	2,745	1,226	1,119	13,527	18,994	23,721	20,750	22,809	24,988	22,838	134,101	147,628
22	Total C/I	3,497,768	6,768,351	8,710,195	8,932,804	7,871,887	5,951,500	41,732,505	3,317,244	2,042,127	1,388,986	1,297,221	1,403,097	1,864,254	11,312,928	53,045,433
23																
24	**Sales Volume**	**7,621,275**	**15,151,339**	**18,564,916**	**19,235,755**	**16,626,366**	**12,730,891**	**89,930,543**	**7,088,327**	**4,131,122**	**2,798,296**	**2,544,109**	**2,743,313**	**3,638,592**	**22,943,759**	**112,874,302**
25																
26	Transportation Sales															
27																
28	G-41	119,167	221,006	278,363	271,664	291,181	209,928	1,391,308	122,067	67,666	41,860	37,179	45,772	66,774	381,320	1,772,628
29	G-42	490,612	985,386	1,272,438	1,269,953	1,421,446	965,619	6,405,455	408,476	218,484	142,119	148,786	156,523	233,086	1,307,474	7,712,928
30	G-43	171,336	273,775	474,052	635,667	639,286	640,070	2,834,185	(42,441)	154,467	105,703	95,009	101,318	29,980	444,035	3,278,220
31	G-51	34,204	44,818	48,662	52,108	54,612	47,565	281,968	30,643	25,421	21,867	22,818	21,621	28,699	151,070	433,038
32	G-52	114,815	149,201	170,942	161,106	156,270	145,082	897,417	121,882	111,240	87,729	96,784	95,952	110,527	624,114	1,521,530
33	G-53	719,564	750,013	967,870	1,015,900	885,325	855,599	5,194,271	789,671	679,374	585,727	549,825	589,138	608,235	3,801,969	8,996,241
34	G-54	27,363	21,952	26,356	201,506	591,896	862,116	1,731,188	24,657	23,770	14,695	20,728	16,683	19,352	119,885	1,851,073
35	G-63	1,163,535	1,315,856	1,437,706	1,274,535	570,754	520,871	6,283,257	1,043,350	1,307,735	1,147,364	1,261,703	1,384,140	1,142,737	7,287,030	13,570,287
36																
37	Total Trans. Sales	**2,840,596**	**3,762,007**	**4,676,389**	**4,882,439**	**4,610,770**	**4,246,849**	**25,019,049**	**2,498,306**	**2,588,159**	**2,147,063**	**2,232,832**	**2,411,146**	**2,239,390**	**14,116,896**	**39,135,945**
38																
39	Total All Sales	**10,461,871**	**18,913,347**	**23,241,305**	**24,118,194**	**21,237,135**	**16,977,740**	**114,949,592**	**9,586,633**	**6,719,280**	**4,945,359**	**4,776,941**	**5,154,460**	**5,877,982**	**37,060,655**	**152,010,247**

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Normal and Design Year Volumes** **Schedule 11A**

7 **Volumes (Therms)** **Normal Year**

9 **For the Months of 11/01/2008 - 4/30/2009**

Line		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Nov - Apr
13	Pipeline Gas:							
14	Dawn Supply	1,065,528	1,100,655	1,100,655	994,373	1,100,655	1,068,230	6,430,097
15	Niagara Supply	843,956	871,878	871,878	787,212	871,878	843,956	5,090,756
16	TGP Supply (Direct)	5,835,635	5,624,872	5,945,521	5,262,790	6,030,187	5,835,635	34,534,639
17	TGP Zone 6 Purchases	-	-	-	-	-	1,052,918	1,052,918
18	Dracut Winter Supply	1,054,720	5,488,866	5,494,270	4,953,850	370,188	-	17,361,893
19	City Gate Delivered Supply	2,161,680	2,233,736	2,233,736	2,017,568	915,111	1,001,578	10,563,410
20	LNG Truck	225,175	237,785	360,280	302,635	225,175	-	1,351,050
21	Propane Truck	-	-	562,938	-	-	-	562,938
22	PNGTS	29,723	38,730	44,134	37,829	34,227	25,220	209,863
23	Granite Ridge	-	-	-	-	-	-	-
24	Subtotal Pipeline Volumes	11,216,417	15,596,521	16,613,412	14,356,257	9,547,420	9,827,538	77,157,565
25								
26	Storage Gas:							
27	TGP Storage	1,730,245	2,761,546	5,006,091	3,325,384	6,241,851	-	19,065,117
28								
29	Produced Gas:							
30	LNG Vapor	225,175	237,785	416,123	288,224	217,969	25,220	1,410,496
31	Propane	-	96,375	562,938	190,948	-	-	850,261
32	Subtotal Produced Gas	225,175	334,160	979,061	479,172	217,969	25,220	2,260,757
33								
34	Less - Gas Refills:							
35	LNG Truck	(225,175)	(237,785)	(360,280)	(302,635)	(225,175)	-	(1,351,050)
36	Propane	-	-	(562,938)	-	-	-	(562,938)
37	TGP Storage Refill	(768,297)	-	-	-	-	(432,336)	(1,200,633)
38	Subtotal Refills	(993,472)	(237,785)	(923,218)	(302,635)	(225,175)	(432,336)	(3,114,621)
39								
40	Total Sendout Volumes	12,178,365	18,454,442	21,675,346	17,858,179	15,782,065	9,420,421	95,368,818
41								

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11B**

Volumes (Therms) **Design Year**

For the Months of 11/01/2008 - 4/30/2009

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	1,065,528	1,100,655	1,100,655	994,373	1,100,655	1,068,230	6,430,097
Niagara Supply	843,956	871,878	871,878	787,212	871,878	843,956	5,090,756
TGP Supply (Direct)	5,835,635	6,030,187	6,005,868	5,368,172	6,030,187	5,834,735	35,104,783
TGP Zone 6 Purchases	-	-	-	-	-	2,497,641	2,497,641
Dracut Winter Supply	1,692,415	5,584,340	5,584,340	5,043,920	1,324,029	-	19,229,044
City Gate Delivered Supply	2,161,680	2,233,736	2,233,736	2,017,568	1,761,769	17,113	10,425,603
LNG Truck	188,246	239,586	360,280	337,763	225,175	-	1,351,050
Propane Truck	-	-	738,574	524,207	-	-	1,262,781
PNGTS	29,723	38,730	44,134	37,829	34,227	25,220	209,863
Granite Ridge	-	673,724	1,672,600	99,077	-	-	2,445,401
Subtotal Pipeline Volumes	11,817,184	16,772,835	18,612,065	15,210,121	11,347,919	10,286,895	84,047,019
Storage Gas:							
TGP Storage	1,962,625	3,504,624	5,614,964	4,072,965	5,650,992	-	20,806,170
Produced Gas:							
LNG Vapor	188,246	239,586	360,280	396,308	199,055	25,220	1,408,695
Propane	-	87,368	738,574	789,013	102,680	-	1,717,635
Subtotal Produced Gas	188,246	326,954	1,098,854	1,185,321	301,735	25,220	3,126,330
Less - Gas Refills:							
LNG Truck	(188,246)	(239,586)	(360,280)	(337,763)	(225,175)	-	(1,351,050)
Propane	-	-	(738,574)	(524,207)	-	-	(1,262,781)
TGP Storage Refill	(744,879)	(202,658)	-	-	-	(432,336)	(1,379,872)
Subtotal Refills	(933,125)	(442,244)	(1,098,854)	(861,970)	(225,175)	(432,336)	(3,993,704)
Total Sendout Volumes	13,034,930	20,162,170	24,227,029	19,606,438	17,075,471	9,879,778	103,985,815

ENERGY NORTH NATURAL GAS, INC. **Schedule 11C**

d/b/a National Grid NH

Peak 2008 - 2009 Winter Cost of Gas Filing

Capacity Utilization

Volumes (Therms)

	Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
Pipeline Gas:								
Dawn Supply	6,430,097	4,000	7,240,000	89%	6,430,097	4,000	7,240,000	89%
Niagara Supply	5,090,756	3,122	5,650,820	90%	5,090,756	3,122	5,650,820	90%
TGP Supply (Direct)	34,534,639	21,596	39,088,760	88%	35,104,783	21,596	39,088,760	90%
TGP Zone 6 Purchases	1,052,918	-	-	-	2,497,641	-	-	-
Dracut Winter Supply	17,361,893	20,000	36,200,000	48%	19,229,044	20,000	36,200,000	53%
City Gate Delivered Supply	10,563,410	8,000	12,080,000	87%	10,425,603	8,000	12,080,000	86%
LNG Truck	1,351,050	-	-	-	1,351,050	-	-	-
Propane Truck	562,938	-	-	-	1,262,781	-	-	-
PNGTS	209,863	1,000	1,810,000	12%	209,863	1,000	1,810,000	12%
Granite Ridge	-	15,000	27,150,000	0%	2,445,401	15,000	27,150,000	9%
Subtotal Pipeline Volumes	77,157,565				84,047,019			
Storage Gas:								
TGP Storage	19,065,117		25,801,310	74%	20,806,170		25,801,310	81%
Produced Gas:								
LNG Vapor	1,410,496				1,408,695			
Propane	850,260.8				1,717,635			
Subtotal Produced Gas	2,260,757				3,126,330			
Less - Gas Refills:								
LNG Truck	(1,351,050)				(1,351,050)			
Propane	(562,938)				(1,262,781)			
TGP Storage Refill	(1,200,633)				(1,379,872)			
Subtotal Refills	(3,114,621)				(3,993,704)			
Total Sendout Volumes	95,368,818				103,985,815			

ENERGY NORTH NATURAL GAS, INC. **Schedule 11D**
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2008/09 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

80 EDD at Manchester, N.H.

Requirements

Firm Sales	1,306,916
Interruptible Sales	0
Firm Transportation	144,084
Interruptible Transportation	0
Total Requirements	1,451,000

Resources

Purchased Pipeline Gas	718,000
Underground Storage Gas	281,100
Propane Air Production	350,000
LNG Produced Gas	101,900
Third-Party Supply	0
Total Resources	1,451,000

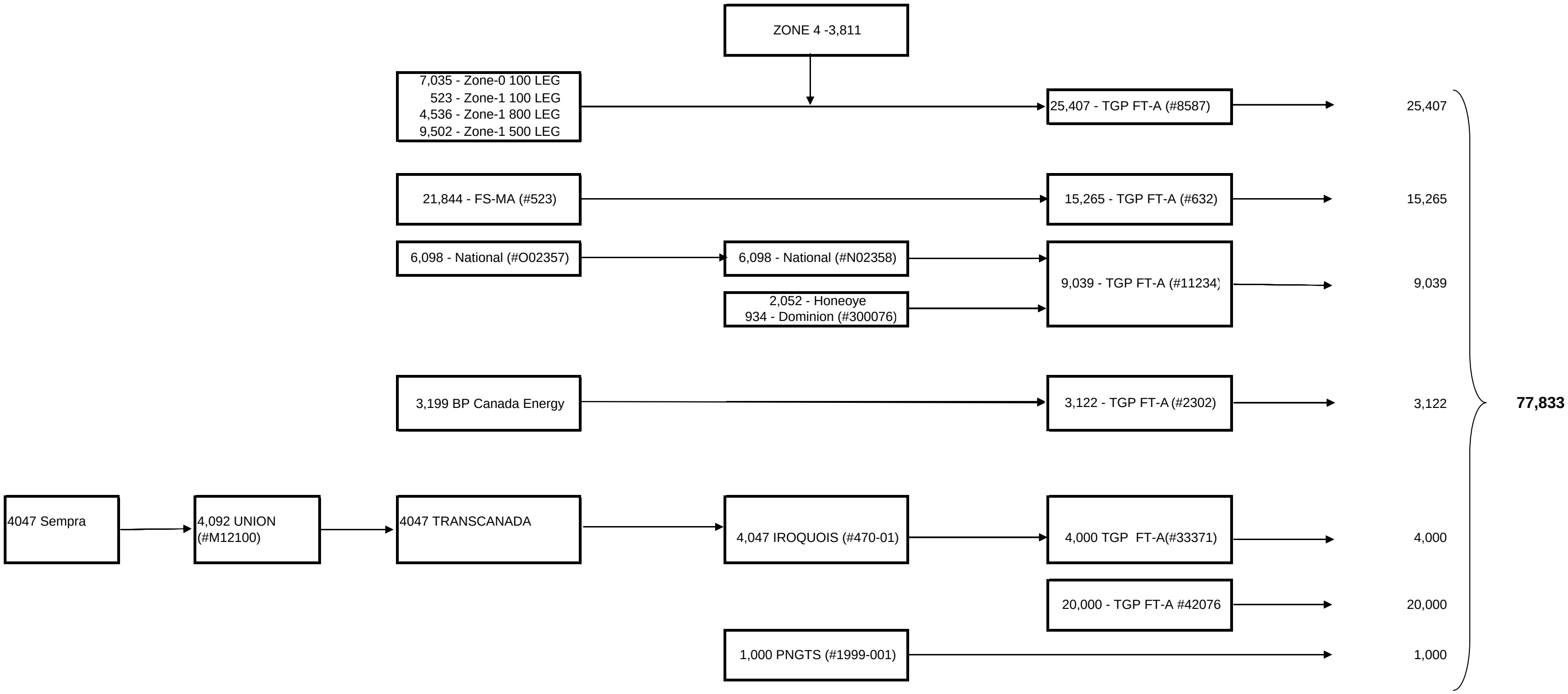
Please refer to the ENGI 2006 IRP filing (DG 06-105) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Theodore Poe, Jr.
Manager, Energy Planning

Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Granite Ridge Energy, LLC (Formerly AES Londonderry, L.L.C.)	-	-	Supply	15,000	450,000	09/30/08	N/a	Mutually agreed upon.
BP Gas & Power Canada, Ltd	-	-	Supply	3,199	1,167,635	3/31/2012	N/a	Terminates
Sempra Energy Trading			Supply	4,047	611,097	3/31/2009	N/a	Terminates
Distrigas of Massachusetts Corp.	FLS	FLS164	Liquid Refill	7 Trucks	50,000	10/31/2009	N/a	Terminates
Distrigas of Massachusetts Corp.	FLS	FLS160	Liquid Refill	Up to 15 trucks	1,000,000 KeySpan Total	10/31/2010	-	Terminates
Virginia Power Energy Marketing			Supply	8,000	1,208,000	10/31/2009	N/a	Terminates
Eastern Propane Gas			Propane Supply	Monthly Take Quantity	TBD	TBD	N/a	Terminates
Florida Power and Light			Supply	20,000	3,020,000	3/31/2009	N/a	Terminates
Chevron Natural Gas			Supply	21,596	3,908,876	4/30/2009	N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2011	3/31/2009	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	4/1/1995	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2008	3/31/2010	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2008	3/31/2010	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	10/31/2011	10/31/2010	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	33371	Transportation	4,000	1,460,000	10/31/2011	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2010	10/31/2009	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2016	4/30/2016	Evergreen Provision
Union Gas Limited	M12	M12100	Transportation	4,092	1,493,580	10/31/2017	10/31/2015	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2007 - Apr 2008 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	16,879,804	32.59%	90.70%
G-42	23,408,418	45.19%	75.65%
G-43	2,222,192	4.29%	40.95%
G-51	3,369,841	6.51%	88.87%
G-52	4,981,787	9.62%	77.08%
G-53	782,078	1.51%	8.20%
G-54	8,893	0.02%	0.49%
G-63	142,696	0.28%	1.07%
Total C/I	51,795,710	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	1,730,819	4.54%	9.30%
G-42	7,535,998	19.76%	24.35%
G-43	3,204,602	8.40%	59.05%
G-51	422,004	1.11%	11.13%
G-52	1,481,438	3.89%	22.92%
G-53	8,757,605	22.97%	91.80%
G-54	1,811,358	4.75%	99.51%
G-63	13,188,325	34.59%	98.93%
Total C/I	38,132,149	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	18,610,624	20.70%	100.00%
G-42	30,944,416	34.41%	100.00%
G-43	5,426,794	6.03%	100.00%
G-51	3,791,845	4.22%	100.00%
G-52	6,463,225	7.19%	100.00%
G-53	9,539,682	10.61%	100.00%
G-54	1,820,252	2.02%	100.00%
G-63	13,331,021	14.82%	100.00%
Total C/I	89,927,859	100.00%	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak	Peak	Total	
	May 07 - Oct 07	Nov 07-Apr 08	May 07 - Apr 08	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	19,546,780	70,719,550	90,266,330	
All Others	992,850	23,953,680	24,946,530	
	20,539,630	94,673,230	115,212,860	
				Ratio
Total Winter Supplies				94,673,230
Total Pipeline Deliveries				90,266,330
Ratio Winter Supplies to Pipeline Supplies				1.049

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

C&I Sales Normalized (Therms)	Jul-07	Aug-07	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	214,236	201,281	415,517	17,119,499	2.43%
G-42	493,714	414,652	908,366	25,505,184	3.56%
G-43	80,020	71,891	151,911	2,513,971	6.04%
G-51	183,687	176,717	360,404	3,460,768	10.41%
G-52	278,758	270,096	548,854	5,095,119	10.77%
G-53	42,620	44,411	87,031	1,044,280	8.33%
G-54	-	-	-	-	0.00%
G-63	932	520	1,452	1,411,872	0.10%
Total C/I	1,293,967	1,179,568	2,473,535	56,150,694	4.41%

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

6 **Underground Storage Gas**

Ln			May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		1,463,289	1,612,371	1,738,469	1,875,126	2,009,712	2,144,299	2,278,885	2,201,771	1,925,616	1,425,007	1,092,468	468,283	2,278,885
11	Injections (MMBtu)	Sch 11A ln 37 /10	168,099	138,232	136,657	134,586	134,586	134,586	95,910	-	-	-	-	43,234	139,144
13	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(19,017)	(12,134)	-	-	-	-	(173,024)	(276,155)	(500,609)	(332,538)	(624,185)	-	(1,906,512)
15	Ending Balance (MMBTu)		1,612,371	1,738,469	1,875,126	2,009,712	2,144,299	2,278,885	2,201,771	1,925,616	1,425,007	1,092,468	468,283	511,517	511,517
18	Beginning Balance		$ 11,572,191	$ 13,187,291	$ 14,541,528	$ 16,039,170	$ 17,224,320	18,325,111	$ 19,432,919	$ 18,881,608	$ 16,513,404	$ 12,220,357	$ 9,368,624	$ 4,015,833	$ 19,432,919
20	Injections	ln 11 * ln 28	2,016,023	1,742,040	1,900,644	1,240,482	1,116,555	1,129,466	924,135	-	-	-	-	415,185	$ 1,339,320
22	Hedging Adjustment (Gain)/Loss		(245,386)	(286,307)	(386,579)	(55,333)	(15,763)	(21,659)							
22	Withdrawals	ln 13 * ln 26	(155,537)	(101,496)	(16,423)	-	-		$ (1,475,445)	$ (2,368,205)	$ (4,293,047)	$ (2,851,733)	$ (5,352,792)	$ -	$ (16,341,221)
24	Ending Balance		$ 13,187,291	$ 14,541,528	$ 16,039,170	$ 17,224,320	$ 18,325,111	$ 19,432,919	$ 18,881,608	$ 16,513,404	$ 12,220,357	$ 9,368,624	$ 4,015,833	$ 4,431,018	$ 4,431,018
26	Average Rate For Withdrawals	ln 18 /ln 9	$7.9083	$8.1788	$8.3646	$8.5536	$8.5705	$8.5460	$8.5274	$8.5756	$8.5756	$8.5756	$8.5756	$8.5756	
28	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$11.9931	$12.6023	$13.9081	$9.2170	$8.2962	$8.3921	$9.6354	$10.0705	$10.3276	$10.3499	$10.1805	$9.6033	
30	Month Dollar Average	ln (18 + ln 24) /2							$ 19,157,264	$ 17,697,506	$ 14,366,880	$ 10,794,490	$ 6,692,228	$ 4,223,425	
32	Money Pool Finance Rate (per Nov 06 - Apr 07 Actuals)								5.22%	5.14%	5.15%	4.82%	3.80%	3.67%	
34	Inventory Finance Charge	ln 30 * ln 32							$ 83,385	$ 75,877	$ 61,634	$ 43,366	$ 21,184	$ 12,916	$ 298,363
35	Financial Expenses								500	500	500	500	500	500	3,000
36	Total Inventory Finance Charges								$ 83,885	$ 76,377	$ 62,134	$ 43,866	$ 21,684	$ 13,416	$ 301,363

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
5

Line			May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
41	**Liquid Propane Gas (LPG)**														
42			May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
43			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
44	Beginning Balance		136,840	136,824	136,784	136,779	136,779	136,779	136,779	136,779	127,142	127,142	108,047	108,047	136,779
45															
46	Injections	Sch 11A ln 36 /10	-	-	-	-	-	-	-	-	56,294	-	-	-	56,294
47															
48	Subtotal		136,840	136,824	136,784	136,779	136,779	136,779	136,779	136,779	183,435	127,142	108,047	108,047	
49															
50	Withdrawals	Sch 11A ln 31 /10	-	-	-	-	-	-	-	(9,637)	(56,294)	(19,095)	-	-	(85,026)
51															
52	Adjutment for change in temperature		(16)	(40)	(5)	-	-	-							
51															
52	Ending Balance		136,824	136,784	136,779	136,779	136,779	136,779	136,779	127,142	127,142	108,047	108,047	108,047	108,047
53															
54															
55	Beginning Balance		$ 2,076,710	$ 2,076,949	$ 2,076,155	$ 2,076,083	$ 2,076,083	$ 2,076,083	$ 2,076,083	$ 2,076,083	$ 1,929,802	$ 2,134,319	$ 1,813,775	$ 1,813,775	$ 2,076,083
56															
57	Injections	ln 46 * ln 67	-	-	-			-	-	-	1,149,518	-	-	-	$ 1,149,518
58															
59	Subtotal		$ 2,076,710	$ 2,076,949	2,076,155	2,076,083	2,076,083	2,076,083	$ 2,076,083	$ 2,076,083	$ 3,079,320	$ 2,134,319	$ 1,813,775	$ 1,813,775	
60															
61	Withdrawals	ln 49 * ln 70	239	(793)	(72)	-	-	-	-	(146,281)	(945,001)	(320,544)	-	-	$ (1,411,827)
62															
63	Ending Balance		$ 2,076,949	$ 2,076,155	$ 2,076,083	$ 2,076,083	$ 2,076,083	$ 2,076,083	$ 2,076,083	$ 1,929,802	$ 2,134,319	$ 1,813,775	$ 1,813,775	$ 1,813,775	$ 1,813,775
64															
65	Average Rate For Withdrawals		$15.1762	$15.1797	$15.1783	$15.1784	$15.1784	$15.1784	$15.1784	$15.1784	$16.7870	$16.7870	$16.7870	$16.7870	
66															
67	Propane Rate for Injections	Sch. 6, ln 144 * 10							$20.2100	$20.3100	$20.4200	$20.2000	$19.9200	$19.4000	
68															
69															
70	Month Dollar Average	ln (55 + ln 63) /2							$ 2,076,083	$ 2,002,942	$ 2,032,060	$ 1,974,047	$ 1,813,775	$ 1,813,775	
71															
72	Money Pool Finance Rate (per Nov 06 - Apr 07 Actuals)								5.22%	5.14%	5.15%	4.82%	3.80%	3.67%	
73															
74	Inventory Finance Charge	ln 70 * ln 72							$ 9,037	$ 8,588	$ 8,718	$ 7,931	$ 5,741	$ 5,547	$ 45,561
75															
76															
77															
78															

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2008 - 2009 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
5

79 **Liquid Natural Gas (LNG)**

Ln			May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
81			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
82	Beginning Balance		9,340	6,897	10,110	8,018	8,018	8,018	12,978	12,978	12,978	7,394	8,835	9,555	12,978
83															
84	Injections	Sch 11A ln 35 /10	-	5,439	-	2,667	2,575	2,667	22,518	23,778	36,028	30,264	22,518	-	135,105
85															
86	Subtotal		9,340	12,336	10,110	10,685	10,593	10,685	35,496	36,756	49,006	37,657	31,352	9,555	
87															
88	Withdrawals	Sch 11A ln 30 /10	(2,443)	(2,226)	(2,092)	(2,667)	(2,575)	(2,667)	(22,518)	(23,778)	(41,612)	(28,822)	(21,797)	(2,522)	(141,050)
89															
90	Ending Balance		6,897	10,110	8,018	8,018	8,018	8,018	12,978	12,978	7,394	8,835	9,555	7,033	7,033
91															
92															
93	Beginning Balance		$ 66,786	$ 49,318	$ 97,996	$ 77,746	$ 76,477	$ 73,179	$ 70,928	$ 98,125	$ 111,644	$ 67,987	$ 82,902	$ 88,903	$ 70,928
94															
95	Injections	ln 84 * ln 105	-	70,254	-	24,582	21,363	22,382	197,448	218,076	338,983	285,371	208,802	-	$ 1,248,679
96															
97	Subtotal		$ 66,786	$ 119,572	$ 97,996	$ 102,328	$ 97,839	$ 95,561	$ 268,376	$ 316,200	$ 450,627	$ 353,358	$ 291,703	$ 88,903	$ 1,319,607
98															
99	Withdrawals	ln 88 * ln 103	(17,469)	(21,576)	(20,250)	(25,851)	(24,660)	(24,633)	(170,252)	(204,556)	$ (382,640)	$ (270,456)	$ (202,800)	$ (23,464)	$ (1,254,168)
100															
101	Ending Balance		$ 49,318	$ 97,996	$ 77,746	$ 76,477	$ 73,179	$ 70,928	$ 98,125	$ 111,644	$ 67,987	$ 82,902	$ 88,903	$ 65,439	$ 65,439
102															
103	Average Rate For Withdrawals		$7.1506	$9.6929	$9.6929	$9.5768	$9.2362	$8.9435	$7.5609	$8.6026	$9.1953	$9.3836	$9.3041	$9.3041	
104															
105	LNG Rate for Injections	Sch. 6, ln 143 * 10							$8.7687	$9.1711	$9.4089	$9.4295	$9.2729	$8.8367	
106															
107															
108	Month Dollar Average	ln (93 + ln 101) /2							$ 84,526	$ 104,885	$ 89,816	$ 75,444	$ 85,903	$ 77,171	
109															
110	Money Pool Finance Rate (per Nov 06 - Apr 07 Actuals)								5.22%	5.14%	5.15%	4.82%	3.80%	3.67%	
111															
112	Inventory Finance Charge	ln 108 * ln 110							$ 368	$ 450	$ 385	$ 303	$ 272	$ 236	$ 2,014
113															
114															
115	Total Fuel Financing	lns 36 + 74 + 112							$ 93,290	$ 85,415	$ 71,237	$ 52,099	$ 27,697	$ 19,199	$ 348,937

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-08	2,840,596	$0.0002	$ 568
Dec-08	3,762,007	0.0002	752
Jan-09	4,676,389	0.0002	935
Feb-09	4,882,439	0.0002	976
Mar-09	4,610,770	0.0002	922
Apr-09	4,246,849	0.0002	849
Total	**25,019,049**		**$ 5,004**

1/ Per Schedule 10B, line 37. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed Eighth Revised Page 86 for calculation of rate.

nationalgrid

July 28, 2008

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: DG 07-093
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
2007-08 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Attached is an original and eight copies of the confidential version of the 2007-08 Winter Period Cost of Gas reconciliation filing for EnergyNorth Natural Gas, Inc d/b/a National Grid NH ("the Company"). This filing is being submitted under protective order and confidential treatment granted by the Commission in Order No. 24,797 dated October 31, 2007 in Docket DG 07-093. The Company is also submitting to the Commission today a confidential version of this filing. This reconciliation compares the actual deferred gas costs to the projections submitted in the Company's 2007-08 Winter Period Cost of Gas Filing submitted to the Commission on August 31, 2007.

The filing shows an under collection for the 2007-08 Winter Period of $2,883,321 summarized as follows:

Winter Period Beginning Balance	$756,088
Less: Cost of Gas Revenue Billed	($100,667,862)
Add: Cost of Gas Allowable (5/1/07 -10/31/07)	$1,086,734
Add: Cost of Gas Allowable (11/1/07 -4/30/08)	$101,708,361
Winter Period Ending Balance	$2,883,321

This filing consists of a six-page summary and nine supporting schedules. Page 1 of the Summary compares the actual deferred gas costs to the projections submitted in the Company's filing including the beginning balance, interest and other allowable adjustments to gas costs, gas costs and gas cost revenue. The result is a net under collection of $2,883,321. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's filing resulting in over collections of $1,409,904 and $305,654, respectively, for a net under collection for all the gas accounts of $1,167,763. The Bad Debt and Working Capital over collections are the result of the New Hampshire Commission approving the Settlement Agreement in DG 07-050, Order No. 24,858 dated May 23, 2008, which revised the Bad Debt percent from 2.56% to 2% effective November 1, 2006 and 1.75% effective November 1, 2007, plus the Working Capital percent from .967% to .645% effective May 1, 2007. Page 3 of the Summary compares actual demand charges of $9,298,378 to the $9,412,304 in demand charges estimated in the filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $91,510,481 compared to $96,718,126 in the filing. The $5,207,645 decrease in commodity costs was caused mainly by lower sendout volumes than originally forecast. The results show that the actual demand and commodity costs were $5,321,572 lower than filed. Page 5 of the Summary provides a variance analysis that explains how much of the difference between actual costs and forecasted costs is due to weather $1,185,807 changes in demand ($6,495,525) and changes in gas prices ($11,855). Page 6 of the Summary shows the calculation of the actual Transportation Cost of Gas Revenue compared to the filing.

The attached Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost collections, and interest applied. The third page of

Schedule 1 provides the same information for bad debt associated with the cost of gas. Schedule 2 provides the details of gas cost by source. Schedule 3 provides the detailed calculation of winter gas cost revenue billed by rate class. Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the winter cost of gas account. Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital. It shows the monthly beginning account balances, working capital allowable, the working capital collections and the interest applied to derive the monthly ending balances. Schedule 6 shows the bad debt and working capital calculation that determines the amount of expense booked for those items. Schedule 7 provides the backup calculations for the revenue billed to recover working capital and bad debt by rate class. Schedule 8 provides a summary of the monthly commodity costs and related volumes. Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

Also enclosed is an Attachment A, which provides the detail calculation of the revised bad debt and working capital prior period adjustment. On May 23, 2008, the Commission approved a Partial Settlement Agreement in DG 07-050 in Order No. 24,858. Specifically, the Order approved the settlement agreement which allowed the Company to use a bad debt percentage of 2.00 percent for the period November 1, 2006 through October 31, 2007 and 1.75 percent for the period November 1, 2007. The 1.75% factor will remain in place until a new bad debt percentage is determined in the base rate case. In addition the Order approved the settlement agreement that allowed the Company to use a net lag of 13.48 days to calculate its cash working capital effective May 1, 2007. The net 13.48 lag days results in a working capital percentage of 0.645 percent. Attachment A provides the calculation of the November 06 – October 07 prior period adjustment for the bad debt and the May 1, 2007 – October 31, 2007 working capital calculations.

Please return one copy of this filing to me bearing the Commission's receipt stamp in the envelope that has been provided for your convenience.

Please contact me by phone at 781-907-1836, or by e-mail at Ann.Leary@us.ngrid.com, if you have any further questions.

Yours truly,

Ann E. Leary

Ann E. Leary
Manager of Pricing – New England

Enclosures

cc: Meredith A. Hatfield, Esq.
Steven V. Camerino, Esq.
Thomas P. O'Neill, Esq.

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2007-2008 COST OF GAS RESULTS
DG 07-093
NOVEMBER 2007 THROUGH APRIL 2008

	Original Filing 1/	Actual		Difference
Peak Gas cost Account 175.20				
Balance 05/01/07- (Over) / Under	$756,088	$756,088	2/	($0)
Peak Gas Costs 5/1/07 - 10/31/07	1,618,891	$1,657,690	3/	38,799
Fuel Financing 5/1/07 - 10/31/07	358,555	142,172	3/	(216,383)
Prior Period Adjustment 5/1/07-10/31/07	17,838	17,994	3/	156
Broker Revenue 5/1/07 - 10/31/07	(397,526)	(407,021)	3/	(9,495)
280 Day Margins 5/1/07 - 10/31/07	(50,976)	(17,159)	4/	33,817
IT Sales Margins 5/1/07 - 10/31/07	(3,815)	(110)	4/	3,705
Off System Sales Margin 5/1/07 - 10/31/07	(40,318)	(39,057)	4/	1,261
Capacity Release 5/1/07 - 10/31/07	(258,694)	(336,984)	4/	(78,290)
Interest 5/1/07 - 10/31/07	76,310	69,208	3/	(7,102)
Sum 5/1/07 - 10/31/07 costs	$1,320,265	$1,086,734		($233,531)
Beginning Balance 10/31/07 (Over)/Under	$2,076,353	$1,842,821		($233,532)
Interest 11/1/07 - 4/30/08	473,812	359,198		(114,614)
Prior Period Adjustments	0	0		0
Interruptible Sales Margin 11/1/07 - 4/30/08	(1,440)	(1,968)		(528)
280-Day Margin 11/1/07 - 4/30/08	(31,779)	(6,165)		25,614
Off System Sales Margin 11/1/07 -4/30/08	(97,560)	(1,427)		96,133
Capacity Release Credits 11/1/07 - 4/30/08	(6,504)	(1,907)		4,597
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	36,142	36,312		170
Broker Revenues 11/1/07 - 4/30/08	(208,267)	(416,517)		(208,250)
Production & Storage	2,105,212	2,105,212		0
Misc Overhead	107,477	107,477		0
Fuel Financing 11/1/07 - 4/30/08	382,055	459,245		77,190
Liberty Consulting Costs	-	32,412		32,412
Transportation Cost of Gas Revenue	(83,086)	(114,678)		(31,592)
Total Adjustment to Costs	$2,676,062	$2,557,193		($118,869)
Gas Costs 11/1/07 - 4/30/08	104,511,540	$99,151,168		($5,360,372)
Total Gas Costs and Adjustments 11/07 -4/08	107,187,602	$101,708,361		($5,479,241)
Gas Cost Billed	($109,263,955)	(100,667,862)		$8,596,093
Total (Over) / Under 04/30/08	$0	$2,883,321		$2,883,321

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2007-2008 COST OF GAS RESULTS
DG 07-093
NOVEMBER 2007 THROUGH APRIL 2008

	Original Filing 1/	Actual		Difference
Bad Debts Account 175.52				
Beginning Balance	$30,927	$30,927		($0)
BD Costs 5/1/07-10/31/07	42,008	32,809	5/	(9,199)
Interest 5/1/07-10/31/07	2,625	2,401	5/	(224)
Beginning Balance 10/31/07 (Over)/Under	$75,560	$66,136		($9,424)
Bad Debt Costs 11/1/07 - 4/30/08	2,731,756	1,759,367		(972,389)
Bad Debt CGA Billed	(2,820,246)	(2,611,964)		208,282
Adjustment		(601,780)		(601,780)
Interest	12,930	(21,663)		(34,593)
Total (Over) / Under 04/30/08	$0	($1,409,904)		($1,409,904)
Working Capital Account 142.20				
Beginning Balance	$15,763	$15,763		($0)
WC Costs 5/1/07-10/31/07	15,655	12,227	6/	(3,428)
Interest 5/1/07-10/31/07	1,160	1,070	6/	(90)
Beginning Balance 10/31/07 (Over)/Under	$32,578	$29,059		($3,519)
Working Capital Costs 11/1/07-4/30/08	1,010,626	639,451		(371,175)
Working Capital CGA Billed	(1,047,991)	(968,381)		79,610
Adjustment	-	(4,154)		(4,154)
Interest	4,787	(1,629)		(6,416)
Total (Over) / Under 04/30/08	$0	($305,654)		-$305,654
Total 175.20, 175.52, 142.20	$0	$1,167,763		$1,167,763

1/ As filed 8-31-07 in the Winter 2007-2008 Cost of Gas DG 07-093
2/ The beginning balance is the sum of the actual April 30, 2007 balance $5,878,396 less the May 2007 Billings of $5,122,308.
3/ The 5/1/07 - 10/31/07 costs are per Schedule 1, page 1, of the Summer 2007 Reconciliation filed on January 30, 2008 in DG 07-034.
4/ The 5/1/07 - 10/31/07 costs are per Schedule 4, of the Summer 2007 Reconciliation filed on January 30, 2008 in DG 07-034.
5/ The 5/1/076 - 10/31/07 costs are per Schedule 1, page 3, of the Summer 2007 Reconciliation filed on January 30, 2008 in DG 07-034
6/ The 5/1/07 - 10/31/07 costs are per Schedule 5, of the Summer 2007 Reconciliation filed on January 30, 2008 in DG 07-034.

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2007-2008 COST OF GAS RESULTS
DG 07-093
SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2007 THROUGH APRIL 2008

	Filing (a)	1/ Actual May 07 - Oct 07 (b)	Actual Nov 07 - Apr 08 (c)	Actual Total Peak Demand (d)=(b)+(c)	Difference (e)=(d)-(a)
Supplies:					
BP/Nexen					
Chevron					
IEC					
Other					
Subtotal Supply Demand Charges	$4,949	$0	$13,250	$13,250	$8,301
Pipelines:					
Iroquois Gas Trans	$160,191	$0	$147,824	$147,824	($12,367)
TGP NET 33371	254,640	-	234,884	234,884	($19,756)
TGP FTA Z5-Z6 2302	92,349	-	85,112	85,112	($7,237)
TGP FTA Z0 - Z6 8587	2,158,540	-	1,991,632	1,991,632	($166,908)
TGP Dracut FTA Z6 - Z6 42076	379,200	-	349,695	349,695	($29,505)
Portland Natual Gas Pipeline	155,125	-	136,411	136,411	($18,714)
ANE (Uniongas and TransCanada)	$185,785	$ -	$191,177	$191,177	$5,392
TGP FTA 632	1,078,930	509,939	501,910	1,011,849	($67,081)
TGP FTA 11234	616,332	291,308	286,728	578,036	($38,296)
National Fuel	245,959	137,618	114,392	252,009	$6,050
Subtotal Pipeline Demand Charges	$5,327,051	$938,864	$4,039,765	$4,978,629	($348,422)
Peaking Supply					
Granite Ridge					
DOMAC					
Transgas Trucking					
Subtotal Peaking Supply	$3,502,326	$122,834	$3,410,733	$3,533,567	$31,241
Propane					
Energy North Propane	$0	$0	$43	$ 43	$43
Storage:					
Demand & Capacity Charges	$1,297,152	$ 616,170.65	$ 591,875.53	$ 1,208,046	($89,106)
Other:					
Capacity Managed	($719,174)	$ (20,178.44)	($414,979)	$ (435,157)	$284,017
Total Demand Charges (Forward to Page 4)	$9,412,304	$1,657,690	$7,640,687	$9,298,378	($113,926)

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2007 Cost of Gas Reconciliation, DG 07-034 filed January 30, 2008

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2007-2008 COST OF GAS RESULTS
DG 07-093
SUMMARY OF COMMODITY COSTS FOR PERIOD
NOVEMBER 2007 THROUGH APRIL 2008

	Filing	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 3):	**$9,412,304**		**$9,298,378**		**($113,926)**	
TGP						
Therms						
Cost						
Spot Gas						
Therms						
Cost						
Canadian						
Therms						
Cost						
PNGTS						
Therms						
Cost						
Granite Ridge						
Therms						
Cost						
City Gate Delivered Supply						
Therms						
Cost						
Storage gas - commodity withdrawn						
Therms						
Cost						
Propane						
Therms						
Cost						
LNG						
Therms						
Cost						
Hedging (Gains) Losses						
Other - Cashout, Broker Penalty, Canadian Managed						
Therms						
Cost						
Prior period Adj						
Subtotal:						
Volumes (net of fuel retention)	100,833,527		94,673,230		(6,160,297)	
Cost	$ 96,718,126	0.9592	$ 91,510,481	0.9666	$ (5,207,645)	0.0074
Total Demand and Commodity Costs	$ 106,130,430		$ 100,808,858		$ (5,321,572)	
Demand (therms):	100,833,527		94,673,230		(6,160,297)	
Firm Gas Sales	96,670,889		88,842,320		(7,828,569)	
Lost Gas (Unaccounted For)	1,266,177		2,285,832		1,019,655	
Unbilled Therms	2,652,559		3,317,645		665,086	
Fuel Retention	-		-		-	
Company Use	243,902		227,433		(16,469)	
Total Demand	100,833,527		94,673,230		(6,160,297)	
						-

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2007-2008 COST OF GAS RESULTS
DG 07-093

Weather Variance - Volume Impact	(A) Actual Volume	(B) Normal Volume	(C) Actual Rate	(A-B)*C Difference
TGP				
Spot Gas				
AES				
PNGTS				
ANE/BP NEXEN				
Domac				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Volume Weather Varaince	94,673,230	93,398,873		$ 1,185,807

Demand Variance - Commodity Costs	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate	(B-A)*C Difference
TGP				
AES Londonderry				
PNGTS				
Canadian				
City Gate Delivered Supply				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Demand Variance (Less: Fuel Retention)	100,833,527	94,673,230		$ (5,309,717)
Demand Variance Net of Weather Variance				(6,495,525)

Rate Variance - Commodity Costs	(A) Actual Volume	(B) Forecast Rate	(C) Actual Rate	(C-B)*A Difference
TGP				
AES Londonderry				
PNGTS				
Canadian				
City Gate Delivered Supply				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Commodity Cost Rate Variance	94,673,230			$ (406,028)
Demand Charge Variance (from page 3)				(113,926)
Other Rate Variance (from page 4)				
Hedging (Gains)/Losses				1,429,887
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments				(921,787)
Total Rate Variance				$ (11,855)
Due to Weather Variance				1,185,807
Due to Demand Variance (from above)				(6,495,525)
Total Gas Cost Variance				$ (5,321,572)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2007-2008 COST OF GAS RESULTS
DG 07-093

	FILING	ACTUAL
Cost of Propane	$ 2,310,315	$ 715,737
Cost of LNG	989,441	293,454
Total Costs	3,299,756	1,009,191
Percentage of Supplies Used For Pressure Support Purposes	14.1%	14.1%
Cost of Supplies Used For Pressure Support Purposes	465,266	142,296
Firm Therms Sold	96,670,889	88,842,320
Firm Therms Transported	19,782,286	27,304,327
Total Therms	116,453,175	116,146,646
Actual Liquid Cost/Therm	0.0040	0.0012
Firm Therms Transported	19,782,286	27,304,327
Liquid Costs Allocated to Transported Therms	79,036	33,452
Prior (Over) or under Collection	4,474	4,474
Total	83,510	37,926
Costs Recovered:		
Therms Transported	19,782,286	27,304,327
Recovery Rate	0.0042	0.0042
Costs Recovered	83,510	114,678
(Over) / Under Collection For Period	-	(76,753)

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

	FOR THE MONTH OF:	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Total
	DAYS IN MONTH	30	31	31	29	31	30		
1	BEGINNING BALANCE	$ 1,842,821	$ 9,843,311	$ 11,750,568	$ 13,627,085	$ 14,554,520	$ 13,715,887	$ 7,915,782	**$ 1,842,821**
2									
3	Add: Actual Costs	12,124,209	19,736,743	22,043,828	20,487,419	16,933,298	7,825,671		**99,151,168**
4									
5	Add. FPO Admin Costs	36,312	-	-	-	-	-		**36,312**
6	Add: MISC OH	17,913	17,913	17,913	17,913	17,913	17,913		**107,477**
7	Add: Production and Storage	350,869	350,869	350,869	350,869	350,869	350,869		**2,105,212**
8	Add: Fuel Financing	40,507	65,535	65,535	87,473	65,054	65,054		**389,157.32**
9	Reverse Fuel Finance Estimate		(23,335)			(65,535)			**(88,869.96)**
10	Add new Fuel Finance Estimate		91,534			67,424			**158,957.42**
11									-
12	Add: Liberty Consulting Expense	-	-	-	32,412	-	-		**32,412**
13									
14	Less: CUSTOMER BILLINGS	(4,551,632)	(18,327,945)	(20,560,320)	(20,041,807)	(18,173,630)	(14,094,745)	(5,032,461)	**(100,782,540)**
15		-	-	-					
16	Less: REFUND	-	-	-	-	-	-		-
17									
18	Less: Broker Revenues	(50,697)	(65,305)	(116,307)	(73,857)	(101,813)	(8,539)	-	**(416,517)**
19									
20	NON FIRM MARGIN AND CREDITS	(2,899)	(5,757)	-	-	-	(2,811)	-	**(11,467)**
21									
22	ENDING BALANCE PRE INTEREST	**$ 9,807,403**	**$ 11,683,560**	**$ 13,552,085**	**$ 14,487,507**	**$ 13,648,100**	**$ 7,869,300**	**$ 2,883,321**	**$ 2,524,123**
23									
24	MONTH'S AVERAGE BALANCE	5,825,112	10,763,436	12,651,327	14,057,296	14,101,310	10,792,593		
25									
26	INTEREST RATE	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%		
27									
28	INTEREST APPLIED	35,908	67,008	75,000	67,013	67,787	46,482		**359,198**
29									
30	ENDING BALANCE	**$ 9,843,311**	**$ 11,750,568**	**$ 13,627,085**	**$ 14,554,520**	**$ 13,715,887**	**$ 7,915,782**	**$ 2,883,321**	**$ 2,883,321**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.40

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-07** **30**	**Dec-07** **31**	**Jan-08** **31**	**Feb-08** **29**	**Mar-08** **31**	**Apr-08** **30**	**May-08**	**Total**
1	BEGINNING BALANCE	$ 2,798,019	$ 144,651	$ 145,552	$ 146,415	$ 147,113	$ 147,820	$ 148,457	**2,798,019**
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		**$ -**
4									
5	Add: MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(2,662,410)	-	-	-	-	-		**(2,662,410)**
8									
9	Add: ADJUSTMENTS	-	-	-	-	-	-	-	-
10									
11	ENDING BALANCE PRE INTEREST	**$ 135,609**	**$ 144,651**	**$ 145,552**	**$ 146,415**	**$ 147,113**	**$ 147,820**	**$ 148,457**	**$ 135,609**
12									
13	MONTH'S AVERAGE BALANCE	1,466,814	144,651	145,552	146,415	147,113	147,820		
14									
15	INTEREST RATE	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%		
16									
17	INTEREST APPLIED	9,042	901	863	698	707	637		**12,848**
18									
19	ENDING BALANCE	**$ 144,651**	**$ 145,552**	**$ 146,415**	**$ 147,113**	**$ 147,820**	**$ 148,457**	**$ 148,457**	**$ 148,457**

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-07** **30**	**Dec-07** **31**	**Jan-08** **31**	**Feb-08** **29**	**Mar-08** **31**	**Apr-08** **30**	**May-08**	**Total**
1	BEGINNING BALANCE	$ 66,136	$ (440,135)	$ (566,187)	$ (718,635)	$ (890,263)	$ (1,069,261)	$ (1,289,664)	**66,136**
2									
3	Add: COST ALLOW	215,696	349,725	390,460	363,048	300,449	139,988		**$ 1,759,367**
4									
5	Prior Period Bad Debt Adj Nov 06 - Oct 07 1/	(601,780)							**(601,780)**
6									
7	Reclass balance to Peak 175.20						-	-	-
8									
9	Less: CUSTOMER BILLINGS	(119,039)	(472,654)	(539,112)	(530,849)	(474,749)	(355,322)	(120,240)	**(2,611,964)**
10									
11	ENDING BALANCE PRE INTEREST	**$ (438,986)**	**$ (563,064)**	**$ (714,838)**	**$ (886,437)**	**$ (1,064,562)**	**$ (1,284,595)**	**$ (1,409,904)**	**$ (1,388,241)**
12									
13	MONTH'S AVERAGE BALANCE	(186,425)	(501,600)	(640,513)	(802,536)	(977,413)	(1,176,928)		
14									
15	INTEREST RATE	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%		
16									
17	INTEREST APPLIED	(1,149)	(3,123)	(3,797)	(3,826)	(4,699)	(5,069)		**$ (21,663)**
18									
19	ENDING BALANCE	**$ (440,135)**	**$ (566,187)**	**$ (718,635)**	**$ (890,263)**	**$ (1,069,261)**	**$ (1,289,664)**	**$ (1,409,904)**	**$ (1,409,904)**

1/ Per the approved Settlement in Order No. 24,858 issued on May 23, 2008 in Docket No. DG 07-050 the Bad Debt rate for November 06 - October 07 was revised from 2.56% to 2.00% and to 1.75% as of November 1, 2007. The above adjustment reflects the percentage change for Nov 06 to Oct 07. See Attachment A for the adjustment calculations

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
OFF PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF:	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Total
	DAYS IN MONTH	30	31	31	29	31	30		
1	BEGINNING BALANCE	$ 49,163	$ (141,273)	$ (142,152)	$ (142,995)	$ (143,677)	$ (144,368)	$ (144,990)	**49,163**
2									
3	Add: COST ALLOW	-	-	-	-	-	-		**$ -**
4									
5	Prior Period Bad Debt Adj Nov 06 - Oct 07 1/	(112,556)			-				**(112,556)**
6									
7	Less: CUSTOMER BILLINGS	(77,597)	-	-	-	-	-	-	**(77,597)**
8									
9	ENDING BALANCE PRE INTEREST	**$ (140,990)**	**$ (141,273)**	**$ (142,152)**	**$ (142,995)**	**$ (143,677)**	**$ (144,368)**	**$ (144,990)**	**$ (140,990)**
10									
11	MONTH'S AVERAGE BALANCE	(45,914)	(141,273)	(142,152)	(142,995)	(143,677)	(144,368)		
12									
13	INTEREST RATE	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%		
14									
15	INTEREST APPLIED	(283)	(879)	(843)	(682)	(691)	(622)		**(4,000)**
16									
17	ENDING BALANCE	**$ (141,273)**	**$ (142,152)**	**$ (142,995)**	**$ (143,677)**	**$ (144,368)**	**$ (144,990)**	**$ (144,990)**	**$ (144,990)**

1/ Per the approved Settlement Order No. 24,858 issued on May 23,2008 in Docket No. DG 07-050 the Bad Debt rate for November 06 - October 07 was revised from 2.56% to 2.00%. See Attachment A for the adjustment calculations.

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
GAS COSTS BY SOURCE
SCHEDULE 2A

	FOR THE MONTH OF:	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**Total**
1	**DEMAND**							
2								
3	ALBERTA NORTHEAST							
4	BP							
5	Other							
6	TOTAL CANADIAN	$ 40,002.51	$ 40,335.48	$ 23,027.07	$ 29,991.09	$ 30,983.20	$ 31,548.00	**$ 195,887.35**
7								
8	PEAKING SUPPLY	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	**120,000.00**
9								
10	TRANSPORT CAPACITY	654,288.17	643,033.38	652,192.80	640,839.39	630,767.77	631,066.39	**3,852,187.90**
11								
12	STORAGE FIXED COSTS	102,399.19	107,891.11	80,096.87	100,640.57	100,497.35	100,350.44	**591,875.53**
13								
14	LNG	219,500.00	986,715.40	913,502.54	878,302.54	292,712.87	-	**3,290,733.35**
15								
16	PROPANE	6.30	4.20	8.70	7.64	7.94	7.94	**42.72**
17								
18	CANADIAN CAPACITY MANAGED	(1,314.86)	(116,941.35)	(67,871.71)	(74,756.95)	(76,188.18)	(77,905.84)	**(414,978.89)**
19								
20	OTHER	532.50	500.00	500.00	500.00	500.00	500.00	**3,032.50**
21								
22	CAPACITY RELEASE ADJUSTMENT	-	-	-	-	-	1,906.83	**1,906.83**
23								
24	**TOTAL DEMAND**	**$ 1,035,413.81**	**$ 1,681,538.22**	**$ 1,621,456.27**	**$ 1,595,524.28**	**$ 999,280.95**	**$ 707,473.76**	**$ 7,640,687.29**
25								
26	**COMMODITY**							
27								
28	ALBERTA NORTHEAST							
29	DTE Energy							
30	SEMPRA							
31	Nexen							
32	SUBTOTAL CANADIAN COMMODITY							
33								
34	PIPELINE TRANSPORT COMM.							
35								
36	PEAKING SUPPLY							
37								
38	GAS SUPPLY							
39								
40	STORAGE COMMODITY							
41								
42	LNG							
43								
44	PROPANE							
45								
46	**OTHER COST ADJUSTMENTS**							
47	CANDIAN CAPACITY MANAGED							
48	SUPPLIER CASHOUT							
49	NET OTHER COST ADJUSTMENTS	(25,199.60)	(221,196.98)	(334,897.02)	(180,748.33)	(62,912.77)	(35,152.00)	**(860,106.70)**
50								
51	**SUBTOTAL COMMODITY COST**	**$ 11,123,530.90**	**$ 18,094,715.91**	**$ 20,422,371.97**	**$ 18,891,894.77**	**$ 15,934,017.08**	**$ 7,343,719.19**	**$ 91,810,249.82**
52								
53	OFF SYSTEM SALES COST							
54	NON-FIRM COST							
55								
56	**TOTAL COMMODITY COST**	**$ 11,088,794.82**	**$ 18,055,204.91**	**$ 20,422,371.97**	**$ 18,891,894.77**	**$ 15,934,017.08**	**$ 7,118,197.01**	**$ 91,510,480.56**

57
58 **ENERGY NORTH NATURAL GAS, INC**
59 **D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND**
60 **NOVEMBER 2007 THROUGH APRIL 2008**
61 **GAS COSTS SUMMARY**
62 **SCHEDULE 2A**
63

	FOR THE MONTH OF:	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**Total**
64								
65								
66	**Total Peak Demand**	**$ 1,035,413.81**	**$ 1,681,538.22**	**$ 1,621,456.27**	**$ 1,595,524.28**	**$ 999,280.95**	**$ 707,473.76**	**$ 7,640,687.29**
67	**Off-Peak Demand**	-	-	-	-	-	-	-
68	**Total Demand**	**$ 1,035,413.81**	**$ 1,681,538.22**	**$ 1,621,456.27**	**$ 1,595,524.28**	**$ 999,280.95**	**$ 707,473.76**	**$ 7,640,687.29**
69								
70	**Total Peak Commodity**	**$ 11,088,794.82**	**$ 18,055,204.91**	**$ 20,422,371.97**	**$ 18,891,894.77**	**$ 15,934,017.08**	**$ 7,118,197.01**	**$ 91,510,480.56**
71	**Off-Peak Commodity**	-	-	-	-	-	-	-
72	**Total Commodity**	**$ 11,088,794.82**	**$ 18,055,204.91**	**$ 20,422,371.97**	**$ 18,891,894.77**	**$ 15,934,017.08**	**$ 7,118,197.01**	**$ 91,510,480.56**
73								
74	**Firm Sendout Costs**	**$ 12,124,208.63**	**$ 19,736,743.13**	**$ 22,043,828.24**	**$ 20,487,419.05**	**$ 16,933,298.03**	**$ 7,825,670.77**	**$ 99,151,167.85**

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

	FOR THE MONTH OF:	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Total
1	**DEMAND**							
2	**Supply**							
3	ALBERTA NORTHEAST							
4	Northeast Gas Markets/BP							
5	Other							
6	**Total Canadian Suppy**	$ 40,002.51	$ 40,335.48	$ 23,027.07	$ 29,991.09	$ 30,983.20	$ 31,548.00	$ 195,887.35
7								
8	**Peaking Suppy**							
9	Granite Ridge							
10								
11	**Transport Capacity**							
12	Iroquois 470-01-RTS	$ 25,016.18	$ 24,778.70	$ 24,659.96	$ 24,475.23	$ 24,435.65	$ 24,457.86	$ 147,823.58
13	National Fuel N02358	19,320.18	16,472.74	21,807.97	18,960.53	18,930.28	18,900.03	114,391.73
14	PNGTS FT-1999-001	24,736.13	25,250.18	25,773.35	25,245.90	15,514.17	19,634.53	136,154.26
15	TGP 632 FTA	84,880.80	89,910.84	78,024.83	83,160.91	83,031.33	82,901.75	501,910.46
16	TGP 2302 FTA Zone 5-6	14,415.32	15,391.46	13,089.15	14,094.87	14,070.22	14,050.50	85,111.52
17	TGP 8587 FTA	337,206.36	312,795.30	353,592.82	329,846.80	329,328.86	328,862.24	1,991,632.38
18	TGP 11234 FTA	48,491.58	51,361.41	44,578.35	47,510.08	47,436.38	47,349.96	286,727.76
19	TGP 33371 NET	39,787.50	42,440.00	36,105.83	38,896.26	38,853.82	38,800.77	234,884.18
20	TGP 42076 FTA	59,215.24	63,200.00	53,814.80	57,907.00	57,821.68	56,086.36	348,045.08
21	Cheveron	1,218.88	1,432.75	745.74	741.81	1,345.38	22.39	5,506.95
22								
23	**Subtotal Transport Capacity**	$ 654,288.17	$ 643,033.38	$ 652,192.80	$ 640,839.39	$ 630,767.77	$ 631,066.39	$ 3,852,187.90
24								
25	**Storage Fixed**							
26	Dominion 300076-Storage	$ 3,057.69	$ 3,037.60	$ 3,021.70	$ 2,998.04	$ 2,994.06	$ 2,988.11	$ 18,097.20
27	NFG Deliverability FSS 2357	39,713.96	53,987.83	24,686.90	38,962.53	38,901.53	38,839.66	235,092.41
28	Tenn Reservation FSMA 523	50,881.03	42,123.41	43,643.88	49,935.61	49,857.37	49,778.28	286,219.58
29	HONEOYE STORAGE SS-NY	8,746.51	8,742.27	8,744.39	8,744.39	8,744.39	8,744.39	52,466.34
30	**Subtotal Storage**	$ 102,399.19	$ 107,891.11	$ 80,096.87	$ 100,640.57	$ 100,497.35	$ 100,350.44	$ 591,875.53
31								
32	**LNG / DISTRIGAS FLS 164**							
33	**LNG/ DISTRIGAS FVS 301**							
34	**LNG/ DISTRIGAS FLS160**							
35	**Transgas Trucking**							
36	**Subtotal Distrigas**	$ 219,500.00	$ 986,715.40	$ 913,502.54	$ 878,302.54	$ 292,712.87	$ -	$ 3,290,733.35
37								
38	**Propane**							
39	En Propane	$ 6.30	$ 4.20	$ 8.70	$ 7.64	$ 7.94	$ 7.94	42.72
40								
41	Intercontinental Exchange	$ 533	$ 500	$ 500	$ 500	$ 500	$ 500	3,032.50
42								
43	**Capacity Managed - Canadian**							
44								
45	**Demand Subtotal**	$ 1,035,413.81	$ 1,681,538.22	$ 1,621,456.27	$ 1,595,524.28	$ 999,280.95	$ 705,566.93	$ 7,638,780.46
46								
47	**Capacity Release Adjustment**							
48	TGP FT-A 42076							
49	PNGTS FT							
50								
51								
52	**TOTAL DEMAND**	$ 1,035,413.81	$ 1,681,538.22	$ 1,621,456.27	$ 1,595,524.28	$ 999,280.95	$ 707,473.76	$ 7,640,687.29

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

53	**FOR THE MONTH OF:**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**Total**
54								
55	**COMMODITY**							
56								
57	**Canadian Supply**							
58	BP							
59	DTE Energy							
60	Sempra							
61	Nexen							
62	**Subtotal Canadian Commodity**							
63								
64	**Pipeline Transport**							
65	ANE Union/Dawn							
66	Dominion							
67	El Paso							
68	Iroquois							
69	National Fuel							
70	PNGTS							
71	**Subtotal Transp Commodity**							
72								
73	**PNGTS Supply**							
74	Dte Energy							
75	Emera							
76	Conoco							
77	**Subtotal PNGTS**							
78								
79	**Gas Supply**							
80	ANE Refund							
81	Chevron							
82	Colonial Energy							
83	Cokinos							
84	Constellation Energy							
85	Coral							
86	Devon Gas							
87	Emera							
88	ETC							
89	FEMT							
90	FPL Energy							
91	Hess							
92	L. Dreyfus							
93	Merrill							
94	NJ Energy							
95	Spark Energy							
96	Tenaska							
97	Total Gas & Power							
98	UBS							
99	VPEM							
100	**Total Other TGP Supply**							
101								
102	**Peaking Supply**							
103	Granite Ridge (formerly AES)							
104								
105	NYMEX Hedging - Settlement							
106								
107	**STORAGE WITHDRAWALS**							
108								
109	**STORAGE INJECTIONS**							
110								
111	DISTRIGAS							
112	LNG VAPOR							
113	LNG INJECTIONS							
114	**Subtotal LNG**							
115								
116	**PROPANE**							
117	Propane Storage Withdrawal							
118	Energy North Propane							
119	**Subtotal Propane**							
120								
121	OP Broker Cashout Trueup							
122	Broker Cashout							
123	**Subtotal Cashouts**							
124								
125	Capacity Managed - Canadian							
126	Broker Inventory							
127	**Subtotal Capacity Managed**							
128								
129	**TOTAL COMMODITY**							
130								
131	Off System Gas Sales Cost							
132	NON-FIRM COST							
133								
134	**NET COMMODITY COST**	**$ 11,088,794.82**	**$ 18,055,204.91**	**$ 20,422,371.97**	**$ 18,891,894.77**	**$ 15,934,017.08**	**$ 7,118,197.01**	**$ 91,510,480.56**

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

FOR THE MONTH OF:		**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**Total**
Peak Demand 175.20		$ 1,035,413.81	$ 1,681,538.22	$ 1,621,456.27	$ 1,595,524.28	$ 999,280.95	$ 707,473.76	$ 7,640,687.29
Peak Commodity 175.20		11,088,794.82	18,055,204.91	20,422,371.97	18,891,894.77	15,934,017.08	7,118,197.01	91,510,480.56
Total Peak Gas Costs		**$ 12,124,208.63**	**$ 19,736,743.13**	**$ 22,043,828.24**	**$ 20,487,419.05**	**$ 16,933,298.03**	**$ 7,825,670.77**	**$ 99,151,167.85**
Off-Peak Demand 175.40	OP	-	-	-	-	-	-	-
Off-Peak Comm 175.40	OP	-	-	-	-	-	-	-
Total Off-Peak Gas Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Firm Sendout Costs		**$ 12,124,208.63**	**$ 19,736,743.13**	**$ 22,043,828.24**	**$ 20,487,419.05**	**$ 16,933,298.03**	**$ 7,825,670.77**	**$ 99,151,167.85**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	Nov-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Total	Total
		OffPeak	Peak						Peak	Peak	OffPeak
1	**VOLUMES**										
2	**RESIDENTIAL**										
3	R-1	32,960	40,203	111,012	117,811	114,960	108,584	97,495	50,661	**640,726**	**32,960**
4	R-1 FPO	2,972	3,834	12,386	13,183	12,919	11,858	10,390	4,886	**69,456**	**2,972**
5	R-3	1,306,239	1,593,292	6,609,977	7,133,154	7,006,542	6,221,957	4,558,163	1,419,167	**34,542,252**	**1,306,239**
6	R-3 FPO	227,899	476,798	1,722,112	1,849,321	1,766,594	1,576,367	1,167,509	377,584	**8,936,285**	**227,899**
7	R-4	35,874	43,758	267,130	400,492	573,388	598,695	576,252	215,389	**2,675,104**	**35,874**
8	R-4 FPO	20,235	8,993	93,200	120,490	193,412	165,321	147,013	47,844	**776,273**	**20,235**
9	Total Residential	1,626,179	2,166,878	8,815,817	9,634,451	9,667,815	8,682,782	6,556,822	2,115,531		
10	**COMMERCIAL/INDUSTRIAL**										
11	G41 - G43	1,105,909	1,355,496	5,640,960	6,829,731	6,499,600	5,734,943	4,138,982	1,401,267	**31,600,979**	**1,105,909**
12	G41 - G43 (FPO)	99,544	100,383	646,837	770,426	743,653	680,102	505,985	137,497	**3,584,883**	**99,544**
13	Total G41- G43	1,205,453	1,455,879	6,287,797	7,600,157	7,243,253	6,415,045	4,644,967	1,538,764		
14	G51 - G63	197,609	379,521	856,521	969,838	1,015,947	928,384	777,823	376,672	**5,304,706**	**197,609**
15	G51 - G63 (FPO)	25,744	46,671	116,516	132,684	129,087	121,706	106,155	58,836	**711,655**	**25,744**
16	Total G51-G63	223,353	426,192	973,037	1,102,522	1,145,034	1,050,090	883,978	435,508		
17	Total Sales Volumes	3,054,984	4,048,950	16,076,651	18,337,130	18,056,102	16,147,917	12,085,767	4,089,803	**88,842,320**	**3,054,984**
18	**TRANSPORTATION**										
19	G41 - G43	259,163	463,948	1,549,551	1,979,750	2,147,413	2,330,229	1,756,969	775,023	**11,002,883**	**259,163**
20	G51 - G63	51,574	1,947,408	2,274,929	2,596,005	2,667,255	2,226,502	2,363,575	2,225,770	**16,301,444**	**51,574**
21	Total Transportation Volumes	310,737	2,411,356	3,824,480	4,575,755	4,814,668	4,556,731	4,120,544	3,000,792	**27,304,327**	**310,737**
22	**Total Volumes**	**3,365,721**	**6,460,306**	**19,901,131**	**22,912,885**	**22,870,770**	**20,704,648**	**16,206,311**	**7,090,595**	**116,146,646**	**3,365,721**
23											
24	**RATES**										
25	Residential	0.87080	1.14400	1.13600	1.11120	1.09920	1.11780	1.17150	1.23890		
26	Residential (FPO)	0.87080	1.1640	1.16400	1.16400	1.16400	1.16400	1.16400	1.16400		
27	C/I Sales G41 to G43	0.87290	1.14410	1.13660	1.11300	1.09860	1.11730	1.16770	1.23900		
28	C/I Sales G41 to G43 (FPO)	0.87290	1.1641	1.16410	1.16410	1.16410	1.16410	1.16410	1.16410		
29	C/I Transport G41 to G43	0.00000	0.0042	0.00420	0.00420	0.00420	0.00420	0.00420	0.00420		
30	C/I Sales G51 to G63	0.86900	1.14350	1.13640	1.11240	1.09770	1.11650	1.16850	1.23840		
31	C/I Sales G51 to G63 (FPO)	0.86900	1.1635	1.16350	1.16350	1.16350	1.16350	1.16350	1.16350		
31	C/I Transport G51 to G63	0.00000	0.0042	0.00420	0.00420	0.00420	0.00420	0.00420	0.00420		
32											
33	**REVENUES**										
34	Residential	$ 1,197,413	$ 1,918,778	$ 7,938,503	$ 8,502,299	$ 8,458,223	$ 7,745,500	$ 6,129,183	$ 2,087,815	**$ 42,780,301**	**$ 1,197,413**
35	Residential (FPO)	$ 218,663	$ 569,924	$ 2,127,440	$ 2,308,205	$ 2,296,485	$ 2,041,128	$ 1,542,198	$ 500,885	**$ 11,386,265**	**$ 218,663**
36	C/I Sales G41 to G43	$ 965,348	$ 1,550,823	$ 6,411,515	$ 7,601,491	$ 7,140,461	$ 6,407,652	$ 4,833,089	$ 1,736,170	**$ 35,681,200**	**$ 965,348**
37	C/I Sales G41 to G43 (FPO)	$ 86,892	$ 116,856	$ 752,983	$ 896,853	$ 865,686	$ 791,707	$ 589,017	$ 160,060	**$ 4,173,163**	**$ 86,892**
38	C/I Transport G41 to G43	$ -	$ 1,949	$ 6,508	$ 8,315	$ 9,019	$ 9,787	$ 7,379	$ 3,255	**$ 46,212**	**$ -**
39	C/I Sales G51 to G63	$ 171,722	$ 433,982	$ 973,350	$ 1,078,848	$ 1,115,205	$ 1,036,541	$ 908,886	$ 466,471	**$ 6,013,283**	**$ 171,722**
40	C/I Sales G51 to G63 (FPO)	$ 22,371	$ 54,302	$ 135,566	$ 154,378	$ 150,193	$ 141,605	$ 123,511	$ 68,456	**$ 828,011**	**$ 22,371**
41	C/I Transport G51 to G63	$ -	$ 8,179	$ 9,555	$ 10,903	$ 11,202	$ 9,351	$ 9,927	$ 9,348	**$ 68,466**	**$ -**
42	**Winter Gas Cost Rev filed**	**$ 2,662,410**	**$ 4,654,792**	**$ 18,355,421**	**$ 20,561,291**	**$ 20,046,474**	**$ 18,183,270**	**$ 14,143,190**	**$ 5,032,461**	**$ 100,976,900**	**$ 2,662,410**
43											
44	Winter Proration	$ -	$ (100,005)	$ (22,028)	$ (971)	$ (4,667)	$ (4,293)	$ (46,954)	$ -	**(178,918)**	**-**
45											
46	Less Occupant Billing	$ -	$ 3,155	$ 5,448	$ -	$ -	$ 5,347	$ 1,492	$ -	**15,442**	**-**
47	Total	$ 2,662,410	$ 4,551,632	$ 18,327,945	$ 20,560,320	$ 20,041,807	$ 18,173,630	$ 14,094,745	$ 5,032,461	$ 100,782,540	$ 2,662,410
48											
49	**Summer Gas Cost Billed (Acct 175.40)**	**$ 2,662,410**									**$ 2,662,410**
50											
51	Winter Gas Costs Billed (Acct 175.20)		**$ 4,541,504**	**$ 18,311,883**	**$ 20,541,102**	**$ 20,021,585**	**$ 18,154,491**	**$ 14,077,439**	**$ 5,019,857**	**$ 100,667,862**	
52	Winter Transportation Gas Costs Billed (Acct 175.20)	**-**	**10,128**	**16,063**	**19,218**	**20,222**	**19,138**	**17,306**	**12,603**	**$ 114,678**	**$ -**
53	**Total Winter Gas Cost Billed (Acct 175.20)**	**$ -**	**$ 4,551,632**	**$ 18,327,945**	**$ 20,560,320**	**$ 20,041,807**	**$ 18,173,630**	**$ 14,094,745**	**$ 5,032,461**	**$ 100,782,540**	**$ 2,662,410**
54											
55				**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
56	Total Sales CGA Billed	**$ 2,662,410**	**$ 4,551,632**	**$ 18,327,945**	**$ 20,560,320**	**$ 20,041,807**	**$ 18,173,630**	**$ 14,094,745**	**$ 5,032,461**	**$ 100,782,540**	**$ 2,662,410**
57											
58	Plus: Working Capital Gas Cost Billed	29,022	44,134	175,235	199,875	196,812	176,012	131,735	44,579	**968,381**	**29,022**
59	Plus: Bad Debt Cost Billed	77,597	119,039	472,654	539,112	530,849	474,749	355,322	120,240	**2,611,964**	**77,597**
60	Plus: Broker Revenues	-	50,696.61	65,305.35	116,307.17	73,856.89	101,812.86	8,538.56	-	**416,517**	**-**
61											
62	**Total Winter Gas Costs Billed**	**$ 2,769,029**	**$ 4,765,501**	**$ 19,041,140**	**$ 21,415,614**	**$ 20,843,325**	**$ 18,926,203**	**$ 14,590,340**	**$ 5,197,280**	**$ 104,779,403**	**$ 2,769,029**

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**Total**
1	INTERRUPTIBLE							
2								
3	280 DAY							
4								
5	OFF SYSTEM GAS SALES MARGIN							
6	PROPANE OFF SYSTEM SALES MARGIN							
7								
8	CAPACITY RELEASE CREDIT							
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	**$ (2,899)**	**$ (5,757)**	**$ -**	**$ -**	**$ -**	**$ (2,811)**	**$ (11,467)**

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
PEAK PERIOD WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	Nov-07 30	Dec-07 31	Jan-08 31	Feb-08 29	Mar-08 31	Apr-08 30	May-08	Total
1	BEGINNING BALANCE	$ 29,059	$ 59,225	$ 11,473	$ (46,322)	$ (111,365)	$ (178,853)	$ (261,076)	**$ 29,059**
2	Add: COST ALLOW	78,182	127,265	142,183	132,144	109,220	50,457		**639,451**
3	Less: CUSTOMER BILLINGS	(44,134)	(175,235)	(199,875)	(196,812)	(176,012)	(131,735)	(44,579)	**(968,381)**
4									**-**
5	Prior Period Working Capital Adj May 07- Oct O7 1/	(4,154)							**(4,154)**
6									**-**
7	Reclass Working Capital to 175.20						-	-	**-**
8									
9	ENDING BALANCE PRE INTEREST	**58,954**	**11,254**	**(46,219)**	**(110,990)**	**(178,157)**	**(260,131)**	**(305,654)**	**(304,025)**
10									
11	MONTH'S AVERAGE BALANCE	44,006	35,239	(17,373)	(78,656)	(144,761)	(219,492)		
12									
13	INTEREST RATE	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%		
14	INTEREST APPLIED	271	219	(103)	(375)	(696)	(945)		**(1,629)**
15	ENDING BALANCE	**$ 59,225**	**$ 11,473**	**$ (46,322)**	**$ (111,365)**	**$ (178,853)**	**$ (261,076)**	**$ (305,654)**	**$ (305,654)**

1/
Per the approved Settlement Order No. 24,858 issued May 24, 2008 in Docket No. DG 07-050 the Working Capital rate was revised to reflect a net lag of 13.48 days, the Working capital percentage is revised from .967% to .to .645% effective as of May 1, 2007. The above adjustment reflects the revised percentages for the period May 07 - Oct 07. See Attachment A for the adjustment calculation.

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
OFF PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF:	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Total
	DAYS IN MONTH	30	31	31	29	31	30		
1	BEGINNING BALANCE	$ 18,806	$ (73,032)	$ (73,487)	$ (73,923)	$ (74,275)	$ (74,632)	$ (74,953)	**18,806**
2	Add:ACTUAL COST	-	-	-	-	-	-		**$ -**
3	Prior Period Working Capital Adj May 07- Oct O7 1/	(62,648)							**(62,648)**
4	Less: CUSTOMER BILLINGS	(29,022)							**(29,022)**
5	ENDING BALANCE PRE INTEREST	**(72,865)**	**(73,032)**	**(73,487)**	**(73,923)**	**(74,275)**	**(74,632)**	**(74,953)**	**(72,865)**
6									
7	MONTH'S AVERAGE BALANCE	(27,029)	(73,032)	(73,487)	(73,923)	(74,275)	(74,632)		
8									
9	INTEREST RATE	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%		
10	INTEREST APPLIED	(167)	(455)	(436)	(352)	(357)	(321)		**(2,088)**
11	ENDING BALANCE	**$ (73,032)**	**$ (73,487)**	**$ (73,923)**	**$ (74,275)**	**$ (74,632)**	**$ (74,953)**	**$ (74,953)**	**$ (74,953)**

1/
Per the approved Settlement Order No 24,858 issued May 23, 2008 in Docket No. DG 07-050 the Working Capital rate was revised to reflect a net lag of 13.48 days, the Working capital percentage is revised from .967% to .to .645% effective as of May 1, 2007. The above adjustment reflects the revised percentages for the period May 07 - Oct 07. See Attachment A for the adjustment calculation.

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Total
1	**Demand**	$ 1,032,515	$ 1,675,781	$ 1,621,456	$ 1,595,524	$ 999,281	$ 704,663	**7,629,221**
2	**Commodity**	11,088,795	18,055,205	20,422,372	18,891,895	15,934,017	7,118,197	**91,510,481**
3	**Total Gas Costs**	**$ 12,121,310**	**$ 19,730,986**	**$ 22,043,828**	**$ 20,487,419**	**$ 16,933,298**	**$ 7,822,860**	**$ 99,139,701**
4								
5	**Working Capital Rate 1/**	0.00645	0.00645	0.00645	0.00645	0.00645	0.00645	
6								
7	**Total Working Capital Costs**	**$ 78,182**	**$ 127,265**	**$ 142,183**	**$ 132,144**	**$ 109,220**	**$ 50,457**	**$ 639,451**
8								
9	**Prior Period Undercollection**	126,015	126,015	126,015	126,015	126,015	126,015	**756,088**
10								
11	**Subtotal Gas Costs, Working Capital & Under Collection**	12,325,507	19,984,266	22,312,026	20,745,578	17,168,532	7,999,332	**100,535,240**
12								
13	**Bad Debt Rate 1/**	0.0175	0.0175	0.0175	0.0175	0.0175	0.0175	
14								
15	**Total Bad Debt Cost**	**$ 215,696**	**$ 349,725**	**$ 390,460**	**$ 363,048**	**$ 300,449**	**$ 139,988**	**$ 1,759,367**

1/ Working Capital and Bad Debt Rates reflect the Settlement Agreement rates as approved in Docket No. DG 07-050, Order No. 24,858 dated May 12, 2008.

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**Total**
1	Demand	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
3	**Total Gas Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
4								
5	Working Capital Rate	0.00645	0.00645	0.00645	0.00645	0.00645	0.00645	
6								
7	**Total Working Capital Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
8								
9	Prior Period Undercollection	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
10								
11	Subtotal Gas Costs, Working Capital & Under Collection	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
12								
13	Bad Debt Rate	0.0175	0.0175	0.0175	0.0175	0.0175	0.0175	
14								
15	**Total Bad Debt Cost**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
SCHEDULE 7
WORKING CAPITAL & BAD DEBT COLLECTED

	FOR MONTH OF:	OffPeak Nov-07	Peak Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	Peak May-08	Total Peak
1	**VOLUMES**									
2	**RESIDENTIAL**									
3	R-1, R-3 and R-4	1,375,073	1,677,253	6,988,119	7,651,457	7,694,890	6,929,236	5,231,910	1,685,217	**37,858,082**
4	R-1, R-3 and R-4 (FPO)	251,106	489,625	1,827,698	1,982,994	1,972,925	1,753,546	1,324,912	430,314	**9,782,014**
5										
6	**COMMERCIAL/INDUSTRIAL**									
7	G41 - G43	1,105,909	1,355,496	5,640,960	6,829,731	6,499,600	5,734,943	4,138,982	1,401,267	**31,600,979**
8	G41 - G43 (FPO)	99,544	100,383	646,837	770,426	743,653	680,102	505,985	137,497	**3,584,883**
9	G51 - G63	197,609	379,521	856,521	969,838	1,015,947	928,384	777,823	376,672	**5,304,706**
10	G51 - G63 (FPO)	25,744	46,671	116,516	132,684	129,087	121,706	106,155	58,836	**711,655**
11										
12	**TRANSPORTATION**									
13	G41 - G43	259,163	463,948	1,549,551	1,979,750	2,147,413	2,330,229	1,756,969	775,023	**11,002,883**
14	G51 - G63	51,574	1,947,408	2,274,929	2,596,005	2,667,255	2,226,502	2,363,575	2,225,770	**16,301,444**
15										
16	**TOTAL VOLUME**	**3,365,721**	**6,460,306**	**19,901,131**	**22,912,885**	**22,870,770**	**20,704,648**	**16,206,311**	**7,090,595**	**116,146,646**
17										
18	**WORKING CAPITAL RATES**									
19	Residential R1, R3 & R4	$0.0095	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	
20	Residential R1, R-3 & R4 (FPO)	$0.0095	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	
21	C/I Sales G41 to G43	$0.0095	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	
22	C/I Sales G41 to G43 (FPO)	$0.0095	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	
23	C/I Sales G51 to G63	$0.0095	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	
24	C/I Sales G51 to G63 (FPO)	$0.0095	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	$0.0109	
25										
26	**WORKING CAPITAL COSTS COLLECTED**									
27	Residential	$ 13,063	$ 18,282	$ 76,170	$ 83,401	$ 83,874	$ 75,529	$ 57,028	$ 18,369	**$ 412,653**
28	Residential (FPO)	2,386	5,337	19,922	21,615	21,505	19,114	14,442	4,690	**106,624**
29	C/I Sales G41 to G43	10,506	14,775	61,486	74,444	70,846	62,511	45,115	15,274	**344,451**
30	C/I Sales G41 to G43 (FPO)	946	1,094	7,051	8,398	8,106	7,413	5,515	1,499	**39,075**
31	C/I Sales G51 to G63	1,877	4,137	9,336	10,571	11,074	10,119	8,478	4,106	**57,821**
32	C/I Sales G51 to G63 (FPO)	245	509	1,270	1,446	1,407	1,327	1,157	641	**7,757**
33										
34	**SUMMER GAS COST WORKING CAPITAL COLLE**	**$ 29,022**	**$ 44,134**	**$ 175,235**	**$ 199,875**	**$ 196,812**	**$ 176,012**	**$ 131,735**	**$ 44,579**	**$ 968,381**
35										
36	**BAD DEBT RATES**									
37	Residential R1, R3 & R4	$0.0254	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	
38	Residential R1 & R3 (FPO)	$0.0254	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	
39	C/I Sales G41 to G43	$0.0254	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	
40	C/I Sales G41 to G43 (FPO)	$0.0254	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	
41	C/I Sales G51 to G63	$0.0254	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	
42	C/I Sales G51 to G63 (FPO)	$0.0254	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	$0.0294	
43										
44	**BAD DEBTS COLLECTED**									
45	Residential R1, R3 & R4	$ 34,927	$ 49,311	$ 205,451	$ 224,953	$ 226,230	$ 203,720	$ 153,818	$ 49,545	**$ 1,113,028**
46	Residential R1, R-3 & R4 (FPO)	6,378	14,395	53,734.32	58,300.02	58,004.00	51,554.25	38,952.41	12,651.23	**287,591**
47	C/I Sales G41 to G43	28,090	39,852	165,844.22	200,794.09	191,088.24	168,607.32	121,686.07	41,197.25	**929,069**
48	C/I Sales G41 to G43 (FPO)	2,528	2,951	19,017.01	22,650.52	21,863.40	19,995.00	14,875.96	4,042.41	**105,396**
49	C/I Sales G51 to G63	5,019	11,158	25,181.72	28,513.24	29,868.84	27,294.49	22,868.00	11,074.16	**155,958**
50	C/I Sales G51 to G63 (FPO)	654	1,372	3,425.57	3,900.91	3,795.16	3,578.16	3,120.96	1,729.78	**20,923**
51										
52	**SUMMER BAD DEBTS COLLECTED**	**$ 77,597**	**$ 119,039**	**$ 472,654**	**$ 539,112**	**$ 530,849**	**$ 474,749**	**$ 355,322**	**$ 120,240**	**$ 2,611,964**

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

	FOR THE MONTH OF:	**Nov-07**		**Dec-07**		**Jan-08**		**Feb-08**		**Mar-08**		**Apr-08**		**Total**	
		Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	**Dollar**	**Volume Dkt**
	TENNESEE COMMODITY														
1	Gas Supply														
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TGP SUPPLY														
6															
7	PNGTS														
8	TOTAL TGP & PNGTS														
9															
10															
11															
12	**PEAKING SUPPLY**														
13	Granite Ridge														
14															
15															
16	BP COMMODITY														
17	SEMPRA														
18	NEXEN														
19	DTE														
20	TOTAL CANADIAN COMMODITY														
21															
22															
23	**LNG**														
24	Distrigas														
25															
26	LNG Vapor														
27	LNG Injections														
28	Subtotal LNG														
29															
30															
31															
32	**Propane**														
33	Propane Withdrawal														
34	EN Propane														
35															
36	Total Propane														
37															
38															
39	Storage Withdrawals														
40															
41															
42	Hedging Settlements														
43															
44	Cashouts														
45															
46	Capacity Managed														
47															
48															
49															
50	Non-Firm Costs														
51															
52															
53	**NET COMMODITY COST**	**$ 11,088,795**	**1,302,199**	**$ 18,055,205**	**2,001,888**	**$ 20,422,372**	**1,990,314**	**$ 18,891,895**	**1,830,650**	**$ 15,934,017**	**1,552,993**	**$ 7,118,197**	**789,279**	**$ 91,510,481**	**9,467,323**

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ENERGY NORTH NATURAL GAS, INC

D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2007 THROUGH APRIL 2008
MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-07	11/01 - 11/30	7.50%	30	7.5000%
Dec-07	12/01 - 012/31	7.33%	31	7.3300%
Jan-08	01/01 - 01/31	6.98%	31	6.9800%
Feb-08	02/01 - 02/28	6.00%	29	6.0000%
Mar-08	03/01 - 03/31	5.66%	31	5.6600%
Apr-08	04/01 - 04/30	5.24%	30	5.2400%

ATTACHMENT A

Part 1: Prior Period Adjustment – Bad Debt and Working Capital

Part 2: Revised Bad Debt and Working Capital

Part 3 Original Bad Debt and Working Capital as filed July 26, 2007 and January 30, 2008

Prior Period Adjustment

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
PEAK BAD DEBT ADJUSTMENT FOR NOV 06 - OCT 07
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-06** **30**	**Dec-06** **31**	**Jan-07** **31**	**Feb-07** **28**	**Mar-07** **31**	**Apr-07** **30**	**May-07** **31**	**Jun-07** **30**	**Jul-07** **31**	**Aug-07** **31**	**Sep-07** **30**	**Oct-07** **31**	**Total**
1	BEGINNING BALANCE	$ -	$ (53,618)	$ (155,436)	$ (279,818)	$ (414,581)	$ (511,608)	$ (570,488)	$ (576,142)	$ (581,035)	$ (586,159)	$ (591,267)	$ (596,459)	**0**
2														
3	Add: COST ALLOW (Net Difference from Revised and Origi	(53,436)	(101,088)	(122,862)	(132,572)	(93,794)	(55,222)	(1,651)	(983)	(1,049)	(998)	(1,286)	(1,390)	**$ (566,333)**
4								-	-	-	-	-	-	
5	Less: CUSTOMER BILLINGS	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	ENDING BALANCE PRE INTEREST	**(53,436)**	**(154,706)**	**(278,298)**	**(412,390)**	**(508,375)**	**(566,831)**	**(572,139)**	**(577,125)**	**(582,084)**	**(587,157)**	**(592,553)**	**(597,850)**	**(566,333)**
8														
9	MONTH'S AVERAGE BALANCE	(26,718)	(104,162)	(216,867)	(346,104)	(461,478)	(539,220)	(571,313)	(576,633)	(581,559)	(586,658)	(591,910)	(597,155)	
10														
11	INTEREST (Net Difference from Revised and Original)	(182)	(730)	(1,520)	(2,191)	(3,233)	(3,657)	(4,003)	(3,910)	(4,075)	(4,110)	(3,906)	(3,930)	**$ (35,447)**
12														
13	ENDING BALANCE	**$ (53,618)**	**$ (155,436)**	**$ (279,818)**	**$ (414,581)**	**$ (511,608)**	**$ (570,488)**	**$ (576,142)**	**$ (581,035)**	**$ (586,159)**	**$ (591,267)**	**$ (596,459)**	**$ (601,780)**	**$ (601,780)**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
OFF PEAK BAD DEBT ADJUSTMENT FOR NOV 06 - OCT 07
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-06** **30**	**Dec-06** **31**	**Jan-07** **31**	**Feb-07** **28**	**Mar-07** **31**	**Apr-07** **30**	**May-07** **31**	**Jun-07** **30**	**Jul-07** **31**	**Aug-07** **31**	**Sep-07** **30**	**Oct-07** **31**	**Total**
1	BEGINNING BALANCE	$ -	$ -	$ (750)	$ (755)	$ (759)	$ (764)	$ (769)	$ (24,960)	$ (42,390)	$ (56,486)	$ (70,244)	$ (84,114)	**0**
2														
3	Add: COST ALLOW (Net Difference from Revised and Origi	-	(748)	-	-	-	-	(24,101)	(17,202)	(13,751)	(13,315)	(13,363)	(27,796)	**$ (110,277)**
4														
5	Add: Adjustment	-	-	-	-	-	-							-
6		-	-	-	-	-	-							
7	Less: CUSTOMER BILLINGS	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9	ENDING BALANCE PRE INTEREST	**0**	**(748)**	**(750)**	**(755)**	**(759)**	**(764)**	**(24,870)**	**(42,162)**	**(56,141)**	**(69,802)**	**(83,607)**	**(111,910)**	**(110,277)**
10														
11	MONTH'S AVERAGE BALANCE	0	(374)	(750)	(755)	(759)	(764)	(12,820)	(33,561)	(49,266)	(63,144)	(76,925)	(98,012)	
12														
13	INTEREST (Net Difference from Revised and Original)	0	(2)	(5)	(4)	(5)	(5)	(90)	(228)	(345)	(442)	(507)	(646)	**$ (2,279)**
14														
15	ENDING BALANCE	**$ -**	**$ (750)**	**$ (755)**	**$ (759)**	**$ (764)**	**$ (769)**	**$ (24,960)**	**$ (42,390)**	**$ (56,486)**	**$ (70,244)**	**$ (84,114)**	**$ (112,556)**	**$ (112,556)**

ATTACHMENT A
Part 1

Prior Period Adjustment

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
PEAK WORKING CAPITAL ADJUSTMENT FOR MAY 07- OCT 07
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF:	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Total
	DAYS IN MONTH:	30	31	31	28	31	30	31	30	31	31	30	31	0
1	BEGINNING BALANCE							$ -	$ (917)	$ (1,468)	$ (2,061)	$ (2,629)	$ (3,361)	$ -
2														
3	Add: COST ALLOW (Net Difference from Revised and Original)							(914)	(544)	(581)	(552)	(712)	(769)	(4,071)
4	Less: WORKING CAPITAL REVENUE BILLED							-	-	-	-	-	-	-
5														
6	ENDING BALANCE PRE INTEREST							**$ (914)**	**$ (1,460)**	**$ (2,049)**	**$ (2,613)**	**$ (3,341)**	**$ (4,130)**	**$ (4,071)**
7														
8	MONTH'S AVERAGE BALANCE							(457)	(1,189)	(1,759)	(2,337)	(2,985)	(3,746)	(2,036)
9														
10	INTEREST (Net Difference from Revised and Original)							(3)	(8)	(12)	(16)	(20)	(24)	(83)
11														
12	ENDING BALANCE							**$ (917)**	**$ (1,468)**	**$ (2,061)**	**$ (2,629)**	**$ (3,361)**	**$ (4,154)**	**$ (4,154)**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
OFF-PEAK WORKING CAPITAL ADJUSTMENT FOR MAY 07 - OCT 07
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF:	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Total
	DAYS IN MONTH	30	31	31	28	31	30	31	0	0	0	0	0	
1	BEGINNING BALANCE							$ -	$ (13,516)	$ (23,291)	$ (31,223)	$ (38,968)	$ (46,777)	$ -
2														
3	Add: COST ALLOW (Net Difference from Revised and Original)							(13,468)	(9,650)	(7,741)	(7,500)	(7,526)	(15,512)	(61,398)
4	Less: WORKING CAPITAL REVENUE BILLED							-	-	-	-	-	-	-
5														
6	ENDING BALANCE PRE INTEREST							**$ (13,468)**	**$ (23,166)**	**$ (31,032)**	**$ (38,723)**	**$ (46,495)**	**$ (62,289)**	**$ (61,398)**
7														
8	MONTH'S AVERAGE BALANCE							(6,734)	(18,341)	(27,162)	(34,973)	(42,732)	(54,533)	(30,699)
9														
10	INTEREST (Net Difference from Revised and Original)							(48)	(125)	(191)	(245)	(282)	(359)	(1,250)
11														
11	ENDING BALANCE							**$ (13,516)**	**$ (23,291)**	**$ (31,223)**	**$ (38,968)**	**$ (46,777)**	**$ (62,648)**	**$ (62,648)**

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Revised Bad Debt

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
PEAK BAD DEBT - REVISED
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: DAYS IN MONTH	Nov-06 30	Dec-06 31	Jan-07 31	Feb-07 28	Mar-07 31	Apr-07 30	May-07	Total
1	BEGINNING BALANCE	$ (83,662)	$ 19,835	$ 62,082	$ 61,159	$ (46,806)	$ (264,293)	$ (420,112)	**(83,662)**
2									
3	Add: COST ALLOW (Schedule 6, line 15)	187,496	354,695	431,095	465,166	329,101	193,763		**$ 1,961,315**
4									
5	Less: CUSTOMER BILLINGS	(83,783)	(312,734)	(432,448)	(573,176)	(545,503)	(347,269)	(119,449)	**(2,414,360)**
6									
7	ENDING BALANCE PRE INTEREST	**20,051**	**61,796**	**60,729**	**(46,851)**	**(263,207)**	**(417,799)**	**(539,561)**	**(536,707)**
8									
9	MONTH'S AVERAGE BALANCE	(31,805)	40,816	61,406	7,154	(155,007)	(341,046)		
10									
11	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%		
12									
13	INTEREST APPLIED	(216)	286	430	45	(1,086)	(2,313)		**$ (2,854)**
14									
15	ENDING BALANCE	**$ 19,835**	**$ 62,082**	**$ 61,159**	**$ (46,806)**	**$ (264,293)**	**$ (420,112)**	**$ (539,561)**	**$ (539,561)**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
OFF PEAK BAD DEBT - REVISED
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: DAYS IN MONTH	Nov-06 30	Dec-06 31	Jan-07 31	Feb-07 28	Mar-07 31	Apr-07 30	May-07	Total
1	BEGINNING BALANCE	$ 36,270	$ (8,902)	$ (6,329)	$ (6,373)	$ (6,413)	$ (6,458)	$ (6,502)	**36,270**
2									
3	Add: COST ALLOW (Schedule 6, line 15)	-	2,626	-	-	-	-		**$ 2,626**
4									
5	Add: Adjustment				-				-
6									
7	Less: CUSTOMER BILLINGS	(45,264)	-	-	-	-	-	-	**(45,264)**
8									
9	ENDING BALANCE PRE INTEREST	**(8,994)**	**(6,276)**	**(6,329)**	**(6,373)**	**(6,413)**	**(6,458)**	**(6,502)**	**(6,368)**
10									
11	MONTH'S AVERAGE BALANCE	13,638	(7,589)	(6,329)	(6,373)	(6,413)	(6,458)		
12									
13	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%		
14									
15	INTEREST APPLIED	92	(53)	(44)	(40)	(45)	(44)		**(134)**
16									
17	ENDING BALANCE	**$ (8,902)**	**$ (6,329)**	**$ (6,373)**	**$ (6,413)**	**$ (6,458)**	**$ (6,502)**	**$ (6,502)**	**$ (6,502)**

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Revised Bad Debt

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS - REVISED

	FOR MONTH OF:	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	Total
1	**Demand**	$ 1,070,745	$ 1,068,299	$ 1,076,304	$ 1,023,848	$ 1,023,868	$ 750,626	**6,013,690**
2	**Commodity**	8,569,033	16,851,383	20,626,785	22,366,467	15,628,397	9,199,501	**93,241,565**
3	**Total Gas Costs**	**$ 9,639,779**	**$ 17,919,682**	**$ 21,703,089**	**$ 23,390,315**	**$ 16,652,264**	**$ 9,950,127**	**$ 99,255,255**
4								
5	**Working Capital Rate**	0.00967	0.00967	0.00967	0.00967	0.00967	0.00967	
6								
7	**Total Working Capital Costs**	**$ 93,217**	**$ 173,283**	**$ 209,869**	**$ 226,184**	**$ 161,027**	**$ 96,218**	**$ 959,798**
8								
9	**Prior Period Undercollection**	(358,219)	(358,219)	(358,219)	(358,219)	(358,219)	(358,219)	**(2,149,312)**
10								
11	**Subtotal Gas Costs, Working Capital & Under Collection**	9,374,777	17,734,747	21,554,739	23,258,280	16,455,073	9,688,126	**98,065,741**
12								
13	**Bad Debt Rate**	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	
14								
15	**Total Bad Debt Cost**	**$ 187,496**	**$ 354,695**	**$ 431,095**	**$ 465,166**	**$ 329,101**	**$ 193,763**	**$ 1,961,315**

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS - REVISED

	FOR MONTH OF:	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	Total
1	Demand	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2	Commodity	$ -	$ 130,054	$ -	$ -	$ -	$ -	**$ 130,054**
3	**Total Gas Costs**	**$ -**	**$ 130,054**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 130,054**
4								
5	Working Capital Rate	0.00967	0.00967	0.00967	0.00967	0.00967	0.00967	
6								
7	**Total Working Capital Costs**	**$ -**	**$ 1,258**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,258**
8								
9	Prior Period Undercollection	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
10								
11	Subtotal Gas Costs, Working Capital & Under Collection	$ -	$ 131,312	$ -	$ -	$ -	$ -	**$ 131,312**
12								
13	Bad Debt Rate	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	
14								
15	**Total Bad Debt Cost**	**$ -**	**$ 2,626**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,626**

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Revised Bad Debt

ENERGYNORTH NATURAL GAS, INC.
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
PEAK PERIOD BAD DEBT - REVISED
SHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: **DAYS IN MONTH**	**May-07** **31**	**Jun-07** **30**	**Jul-07** **31**	**Aug-07** **31**	**Sep-07** **30**	**Oct-07** **31**	**Nov-07** **30**	**Total**
1	BEGINNING BALANCE	$ (420,112)	$ (537,192)	$ (537,423)	$ (537,547)	$ (537,848)	$ (536,934)	$ (535,643)	**$ (420,112)**
2									
3	Add: COST ALLOW (Schedule 6, line 15)	5,711	3,400	3,629	3,453	4,448	4,809	-	**25,451**
4									
5	Less: BAD DEBT BILLED	(119,449)	-	-	-	-	-	-	**(119,449)**
6									
7	ENDING BALANCE PRE INTEREST	**(533,850)**	**(533,792)**	**(533,794)**	**(534,094)**	**(533,399)**	**(532,125)**	**(535,643)**	**(514,110)**
8									
9	MONTH'S AVERAGE BALANCE	(476,981)	(535,492)	(535,609)	(535,820)	(535,624)	(534,530)	(535,643)	
10									
11	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%	-	
12									
13	INTEREST APPLIED	(3,342)	(3,631)	(3,753)	(3,754)	(3,535)	(3,518)		**$ (21,533)**
14									
15	ENDING BALANCE	**$ (537,192)**	**$ (537,423)**	**$ (537,547)**	**$ (537,848)**	**$ (536,934)**	**$ (535,643)**	**$ (535,643)**	**$ (535,643)**

ENERGYNORTH NATURAL GAS, INC.
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
OFF PEAK BAD DEBT - REVISED
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: **DAYS IN MONTH**	**May-07** **31**	**Jun-07** **30**	**Jul-07** **31**	**Aug-07** **31**	**Sep-07** **30**	**Oct-07** **31**	**Nov-07**	**Total**
1	BEGINNING BALANCE	$ (6,502)	$ 9,855	$ (25,187)	$ (45,301)	$ (60,158)	$ (79,760)	$ (63,393)	**$ (6,502)**
2									
3	Add: COST ALLOW (Schedule 6, line 16)	83,350	59,487	47,552	46,045	46,209	96,132	-	**378,774**
4									
5	Less: BAD DEBT BILLED	(67,005)	(94,476)	(67,421)	(60,533)	(65,352)	(79,295)	(77,597)	**(511,678)**
6									
7	ENDING BALANCE PRE INTEREST	**9,843**	**(25,135)**	**(45,055)**	**(59,790)**	**(79,300)**	**(62,923)**	**(140,990)**	**(139,406)**
8									
9	MONTH'S AVERAGE BALANCE	1,670	(7,640)	(35,121)	(52,545)	(69,729)	(71,342)	(102,192)	
10									
11	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%	-	
12									
13	INTEREST APPLIED	12	(52)	(246)	(368)	(460)	(470)		**$ (1,584)**
14									
15	ENDING BALANCE	**$ 9,855**	**$ (25,187)**	**$ (45,301)**	**$ (60,158)**	**$ (79,760)**	**$ (63,393)**	**$ (140,990)**	**$ (140,990)**

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
PEAK WORKING CAPITAL - REVISED
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF:	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Total**
	DAYS IN MONTH:	31	30	31	31	30	31		
1	BEGINNING BALANCE	$ 59,954	$ 17,864	$ 19,079	$ 20,380	$ 21,633	$ 23,206	$ 24,905	**$ 59,954**
2									
3	Add: COST ALLOW (Schedule 6, line 8)	1,830	1,089	1,163	1,107	1,425	1,541	-	**8,155**
4	Less: WORKING CAPITAL REVENUE BILLED	(44,192)	-	-	-	-	-	-	**(44,192)**
5									
6	ENDING BALANCE PRE INTEREST	**$ 17,592**	**$ 18,954**	**$ 20,242**	**$ 21,486**	**$ 23,059**	**$ 24,747**	**$ 24,905**	**$ 23,918**
7									
8	MONTH'S AVERAGE BALANCE	38,773	18,409	19,660	20,933	22,346	23,976		
9									
10	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%		
11	INTEREST APPLIED	272	125	138	147	147	158		**987**
12	ENDING BALANCE	**$ 17,864**	**$ 19,079**	**$ 20,380**	**$ 21,633**	**$ 23,206**	**$ 24,905**	**$ 24,905**	**$ 24,905**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
OFF-PEAK WORKING CAPITAL- REVISED
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF:	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Total**
	DAYS IN MONTH	31	30	31	31	30	31		
1	BEGINNING BALANCE	$ (3,462)	$ (1,563)	$ (17,633)	$ (27,501)	$ (35,336)	$ (44,967)	$ (43,842)	**(3,462)**
2									
3	Add: COST ALLOW (Schedule 6, line 8)	26,977	19,331	15,507	15,023	15,076	31,073	-	**$ 122,988**
4	Less: WORKING CAPITAL REVENUE BILLED	(25,061)	(35,335)	(25,216)	(22,640)	(24,443)	(29,658)	(29,022)	**(191,376)**
5									
6	ENDING BALANCE PRE INTEREST	**$ (1,545)**	**$ (17,568)**	**$ (27,343)**	**$ (35,117)**	**$ (44,703)**	**$ (43,551)**	**$ (72,865)**	**$ (71,850)**
7									
8	MONTH'S AVERAGE BALANCE	(2,503)	(9,566)	(22,488)	(31,309)	(40,020)	(44,259)		
9									
10	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%		
11	INTEREST APPLIED	(18)	(65)	(158)	(219)	(264)	(291)		**(1,015)**
12	ENDING BALANCE	**$ (1,563)**	**$ (17,633)**	**$ (27,501)**	**$ (35,336)**	**$ (44,967)**	**$ (43,842)**	**$ (72,865)**	**$ (72,865)**

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Revised Bad Debt and Working Capital

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
SCHEDULE 6
OFF PEAK BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Total
1	**Demand**	$ 514,406	$ 543,063	$ 523,407	$ 532,287	$ 537,855	$ 542,069	**$ 3,193,087**
2	**Commodity**	3,668,111	2,453,959	1,880,708	1,796,937	1,799,552	4,275,476	**15,874,743**
3	**Total Gas Costs**	**$ 4,182,517**	**$ 2,997,022**	**$ 2,404,116**	**$ 2,329,224**	**$ 2,337,406**	**$ 4,817,546**	**$ 19,067,831**
4								
5	**Working Capital Rate**	0.00645	0.00645	0.00645	0.00645	0.00645	0.00645	
6								
7	**Total Working Capital Costs**	**$ 26,977**	**$ 19,331**	**$ 15,507**	**$ 15,023**	**$ 15,076**	**$ 31,073**	**$ 122,988**
8								
9	**Prior Period (Over)Undercollection**	$ (42,019)	$ (42,019)	$ (42,019)	$ (42,019)	$ (42,019)	$ (42,019)	**$ (252,111)**
10								
11	**Subtotal Gas Costs, Working Capital & Under Collection**	$ 4,167,476	$ 2,974,334	$ 2,377,604	$ 2,302,229	$ 2,310,464	$ 4,806,600	
12								
13	**Bad Debt Rate**	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	
14								
15	**Total Bad Debt Cost**	**$ 83,350**	**$ 59,487**	**$ 47,552**	**$ 46,045**	**$ 46,209**	**$ 96,132**	**$ 378,774**

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2002
SCHEDULE 6
PEAK BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Total
1	**Demand**	$ 329,488	$ 241,078	$ 268,980	$ 272,579	$ 273,983	$ 271,583	**$ 1,657,690**
2	**Commodity**	-	-	-	-	-	-	-
3	**Margins and Capacity Release**	(45,773)	(72,169)	(88,681)	(101,021)	(52,994)	(32,672)	**(393,310)**
4	**Total Gas Costs**	**$ 283,715**	**$ 168,909**	**$ 180,299**	**$ 171,558**	**$ 220,988**	**$ 238,910**	**$ 1,264,380**
5								
6	**Working Capital Rate**	0.00645	0.00645	0.00645	0.00645	0.00645	0.00645	
7								
8	**Total Working Capital Costs**	**$ 1,830**	**$ 1,089**	**$ 1,163**	**$ 1,107**	**$ 1,425**	**$ 1,541**	**$ 8,155**
9								
10	**Prior Period (Over)Undercollection**	-	-	-	-	-	-	-
11								
12	**Subtotal Gas Costs, Working Capital & Under Collection**	$ 285,545	$ 169,999	$ 181,462	$ 172,664	$ 222,414	$ 240,451	$ 1,272,535
13								
14	**Bad Debt Rate**	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	-
15								
16	**Total Bad Debt Cost**	**$ 5,711**	**$ 3,400**	**$ 3,629**	**$ 3,453**	**$ 4,448**	**$ 4,809**	**$ 25,451**

Original Filed Bad Debt

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
PEAK BAD DEBT - AS FILED JULY 26, 2007
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-06** **30**	**Dec-06** **31**	**Jan-07** **31**	**Feb-07** **28**	**Mar-07** **31**	**Apr-07** **30**	**May-07**	**Total**
1	BEGINNING BALANCE	$ (83,662)	$ 73,453	$ 217,518	$ 340,977	$ 367,776	$ 247,315	$ 150,375	**(83,662)**
2									
3	Add: COST ALLOW (Original costs- Sched 6, line 15)	240,932	455,783	553,957	597,738	422,895	248,985		**$ 2,520,290**
4									
5	Less: CUSTOMER BILLINGS	(83,783)	(312,734)	(432,448)	(573,176)	(545,503)	(347,269)	(119,449)	**(2,414,360)**
6									
7	ENDING BALANCE PRE INTEREST	**73,487**	**216,502**	**339,027**	**365,540**	**245,168**	**149,031**	**30,927**	**22,268**
8									
9	MONTH'S AVERAGE BALANCE	(5,087)	144,978	278,273	353,259	306,472	198,173		
10									
11	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%		
12									
13	INTEREST APPLIED	(34)	1,016	1,950	2,236	2,147	1,344		**$ 8,659**
14									
15	ENDING BALANCE	**$ 73,453**	**$ 217,518**	**$ 340,977**	**$ 367,776**	**$ 247,315**	**$ 150,375**	**$ 30,927**	**$ 30,927**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
OFF PEAK BAD DEBT AS FILED JULY 26, 2007
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-06** **30**	**Dec-06** **31**	**Jan-07** **31**	**Feb-07** **28**	**Mar-07** **31**	**Apr-07** **30**	**May-07**	**Total**
1	BEGINNING BALANCE	$ 36,270	$ (8,902)	$ (5,579)	$ (5,618)	$ (5,654)	$ (5,694)	$ (5,733)	**36,270**
2									
3	Add: COST ALLOW (Original costs- Sched 6, line 15)	-	3,375	-	-	-	-		**$ 3,375**
4									
5	Add: Adjustment				-				-
6									
7	Less: CUSTOMER BILLINGS	(45,264)	-	-	-	-	-	-	**(45,264)**
8									
9	ENDING BALANCE PRE INTEREST	**(8,994)**	**(5,528)**	**(5,579)**	**(5,618)**	**(5,654)**	**(5,694)**	**(5,733)**	**(5,620)**
10									
11	MONTH'S AVERAGE BALANCE	13,638	(7,215)	(5,579)	(5,618)	(5,654)	(5,694)		
12									
13	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%		
14									
15	INTEREST APPLIED	92	(51)	(39)	(36)	(40)	(39)		**(113)**
16									
17	ENDING BALANCE	**$ (8,902)**	**$ (5,579)**	**$ (5,618)**	**$ (5,654)**	**$ (5,694)**	**$ (5,733)**	**$ (5,733)**	**$ (5,733)**

Original Filed Bad Debt

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS - AS FILED JULY 26, 2007

	FOR MONTH OF:	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	Total
1	**Demand**	$ 1,070,745	$ 1,068,299	$ 1,076,304	$ 1,023,848	$ 1,023,868	$ 750,626	**6,013,690**
2	**Commodity**	8,569,033	16,851,383	20,626,785	22,366,467	15,628,397	9,199,501	**93,241,565**
3	**Total Gas Costs**	**$ 9,639,779**	**$ 17,919,682**	**$ 21,703,089**	**$ 23,390,315**	**$ 16,652,264**	**$ 9,950,127**	$ 99,255,255
4								
5	**Working Capital Rate**	0.00967	0.00967	0.00967	0.00967	0.00967	0.00967	
6								
7	**Total Working Capital Costs**	**$ 93,217**	**$ 173,283**	**$ 209,869**	**$ 226,184**	**$ 161,027**	**$ 96,218**	**$ 959,798**
8								
9	**Prior Period Undercollection**	(358,219)	(358,219)	(358,219)	(358,219)	(358,219)	(358,219)	**(2,149,312)**
10								
11	**Subtotal Gas Costs, Working Capital & Under Collection**	9,374,777	17,734,747	21,554,739	23,258,280	16,455,073	9,688,126	**98,065,741**
12								
13	**Bad Debt Rate**	0.0257	0.0257	0.0257	0.0257	0.0257	0.0257	
14								
15	**Total Bad Debt Cost**	**$ 240,932**	**$ 455,783**	**$ 553,957**	**$ 597,738**	**$ 422,895**	**$ 248,985**	**$ 2,520,290**

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2006 THROUGH APRIL 2007
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS - AS FILED JULY 26, 2007

	FOR MONTH OF:	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	Total
1	Demand	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2	Commodity	$ -	$ 130,054	$ -	$ -	$ -	$ -	**$ 130,054**
3	**Total Gas Costs**	**$ -**	**$ 130,054**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 130,054**
4								
5	Working Capital Rate	0.00967	0.00967	0.00967	0.00967	0.00967	0.00967	
6								
7	**Total Working Capital Costs**	**$ -**	**$ 1,258**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,258**
8								
9	Prior Period Undercollection	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
10								
11	Subtotal Gas Costs, Working Capital & Under Collection	$ -	$ 131,312	$ -	$ -	$ -	$ -	**$ 131,312**
12								
13	Bad Debt Rate	0.0257	0.0257	0.0257	0.0257	0.0257	0.0257	
14								
15	**Total Bad Debt Cost**	**$ -**	**$ 3,375**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,375**

00000105

Original Filed Bad Debt

ENERGYNORTH NATURAL GAS, INC.
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
PEAK PERIOD BAD DEBT - AS FILED JANUARY 30, 2008
SHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: DAYS IN MONTH	May-07 31	Jun-07 30	Jul-07 31	Aug-07 31	Sep-07 30	Oct-07 31	Nov-07 30	Total
1	BEGINNING BALANCE	$ 150,375	$ 38,950	$ 43,612	$ 48,612	$ 53,420	$ 59,525	$ 66,136	**$ 150,375**
2									
3	Add: COST ALLOW	7,362	4,383	4,679	4,452	5,734	6,199	-	**32,809**
4									
5	Less: BAD DEBT BILLED	(119,449)	-	-	-	-	-	-	**(119,449)**
6									
7	ENDING BALANCE PRE INTEREST	**38,289**	**43,333**	**48,290**	**53,064**	**59,154**	**65,724**	**66,136**	**63,735**
8									
9	MONTH'S AVERAGE BALANCE	94,332	41,141	45,951	50,838	56,287	62,625	66,136	
10									
11	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%	-	
12									
13	INTEREST APPLIED	661	279	322	356	371	412		**$ 2,401**
14									
15	ENDING BALANCE	**$ 38,950**	**$ 43,612**	**$ 48,612**	**$ 53,420**	**$ 59,525**	**$ 66,136**	**$ 66,136**	**$ 66,136**

ENERGYNORTH NATURAL GAS, INC.
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
OFF PEAK BAD DEBT - AS FILED JANUARY 30, 2008
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: DAYS IN MONTH	May-07 31	Jun-07 30	Jul-07 31	Aug-07 31	Sep-07 30	Oct-07 31	Nov-07	Total
1	BEGINNING BALANCE	$ (5,733)	$ 34,815	$ 17,203	$ 11,185	$ 10,086	$ 4,354	$ 49,163	**$ (5,733)**
2									
3	Add: COST ALLOW	107,450	76,688	61,303	59,360	59,572	123,928	-	**488,303**
4									
5	Less: BAD DEBT BILLED	(67,005)	(94,476)	(67,421)	(60,533)	(65,352)	(79,295)	(77,597)	**(511,678)**
6									
7	ENDING BALANCE PRE INTEREST	**34,713**	**17,027**	**11,086**	**10,012**	**4,307**	**48,987**	**(28,434)**	**(29,108)**
8									
9	MONTH'S AVERAGE BALANCE	14,490	25,921	14,145	10,599	7,196	26,670	10,364	
10									
11	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%	-	
12									
13	INTEREST APPLIED	102	176	99	74	47	176		**$ 674**
14									
15	ENDING BALANCE	**$ 34,815**	**$ 17,203**	**$ 11,185**	**$ 10,086**	**$ 4,354**	**$ 49,163**	**$ (28,434)**	**$ (28,434)**

00000106

Original Filed Working Capital

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
PEAK WORKING CAPITAL - AS FILED JANUARY 30, 2008
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	**May-07** 31	**Jun-07** 30	**Jul-07** 31	**Aug-07** 31	**Sep-07** 30	**Oct-07** 31	**Nov-07**	**Total**
1	BEGINNING BALANCE	$ 59,954	$ 18,781	$ 20,547	$ 22,441	$ 24,263	$ 26,567	$ 29,059	**$ 59,954**
2									
3	Add: COST ALLOW (Original costs- Sched 6, line 7)	2,744	1,633	1,743	1,659	2,137	2,310	-	**12,227**
4	Less: WORKING CAPITAL REVENUE BILLED	(44,192)	-	-	-	-	-	-	**(44,192)**
5									
6	ENDING BALANCE PRE INTEREST	**$ 18,506**	**$ 20,414**	**$ 22,291**	**$ 24,100**	**$ 26,400**	**$ 28,877**	**$ 29,059**	**$ 27,989**
7									
8	MONTH'S AVERAGE BALANCE	39,230	19,598	21,419	23,270	25,331	27,722		
9									
10	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%		
11	INTEREST APPLIED	275	133	150	163	167	182		**1,070**
12	ENDING BALANCE	**$ 18,781**	**$ 20,547**	**$ 22,441**	**$ 24,263**	**$ 26,567**	**$ 29,059**	**$ 29,059**	**$ 29,059**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
OFF-PEAK WORKING CAPITAL - AS FILED JANUARY 30, 2008
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH	**May-07** 31	**Jun-07** 30	**Jul-07** 31	**Aug-07** 31	**Sep-07** 30	**Oct-07** 31	**Nov-07**	**Total**
1	BEGINNING BALANCE	$ (3,462)	$ 11,952	$ 5,658	$ 3,723	$ 3,632	$ 1,810	$ 18,806	**(3,462)**
2									
3	Add: COST ALLOW (Original costs- Sched 6, line 8)	40,445	28,981	23,248	22,524	22,603	46,586	-	**$ 184,386**
4	Less: WORKING CAPITAL REVENUE BILLED	(25,061)	(35,335)	(25,216)	(22,640)	(24,443)	(29,658)	(29,022)	**(191,376)**
5									
6	ENDING BALANCE PRE INTEREST	**$ 11,922**	**$ 5,598**	**$ 3,690**	**$ 3,606**	**$ 1,792**	**$ 18,738**	**$ (10,216)**	**$ (10,451)**
7									
8	MONTH'S AVERAGE BALANCE	4,230	8,775	4,674	3,664	2,712	10,274		
9									
10	INTEREST RATE	8.25%	8.25%	8.25%	8.25%	8.03%	7.75%		
11	INTEREST APPLIED	30	60	33	26	18	68		**235**
12	ENDING BALANCE	**$ 11,952**	**$ 5,658**	**$ 3,723**	**$ 3,632**	**$ 1,810**	**$ 18,806**	**$ (10,216)**	**$ (10,216)**

Original Filed Bad Debt and Working Capital

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2007
SCHEDULE 6
OFF PEAK BAD DEBT AND WORKING CAPITAL COSTS - AS FILED JANUARY 30, 2008

	FOR MONTH OF:	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Total
1	**Demand**	$ 514,406	$ 543,063	$ 523,407	$ 532,287	$ 537,855	$ 542,069	**$ 3,193,087**
2	**Commodity**	3,668,111	2,453,959	1,880,708	1,796,937	1,799,552	4,275,476	**15,874,743**
3	**Total Gas Costs**	**$ 4,182,517**	**$ 2,997,022**	**$ 2,404,116**	**$ 2,329,224**	**$ 2,337,406**	**$ 4,817,546**	**$ 19,067,831**
4								
5	**Working Capital Rate**	0.00967	0.00967	0.00967	0.00967	0.00967	0.00967	
6								
7	**Total Working Capital Costs**	**$ 40,445**	**$ 28,981**	**$ 23,248**	**$ 22,524**	**$ 22,603**	**$ 46,586**	**$ 184,386**
8								
9	**Prior Period (Over)Undercollection**	$ (42,019)	$ (42,019)	$ (42,019)	$ (42,019)	$ (42,019)	$ (42,019)	**$ (252,111)**
10								
11	**Subtotal Gas Costs, Working Capital & Under Collection**	$ 4,180,944	$ 2,983,985	$ 2,385,345	$ 2,309,729	$ 2,317,991	$ 4,822,113	
12								
13	**Bad Debt Rate**	0.0257	0.0257	0.0257	0.0257	0.0257	0.0257	
14								
15	**Total Bad Debt Cost**	**$ 107,450**	**$ 76,688**	**$ 61,303**	**$ 59,360**	**$ 59,572**	**$ 123,928**	**$ 488,303**

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
MAY THROUGH OCTOBER 2002
SCHEDULE 6
PEAK BAD DEBT AND WORKING CAPITAL COSTS - AS FILED JANUARY 30, 2008

	FOR MONTH OF:	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Total
1	**Demand**	$ 329,488	$ 241,078	$ 268,980	$ 272,579	$ 273,983	$ 271,583	**$ 1,657,690**
2	**Commodity**	-	-	-	-	-	-	**-**
3	**Margins and Capacity Release**	(45,773)	(72,169)	(88,681)	(101,021)	(52,994)	(32,672)	**(393,310)**
4	**Total Gas Costs**	**$ 283,715**	**$ 168,909**	**$ 180,299**	**$ 171,558**	**$ 220,988**	**$ 238,910**	**$ 1,264,380**
5								
6	**Working Capital Rate**	0.00967	0.00967	0.00967	0.00967	0.00967	0.00967	
7								
8	**Total Working Capital Costs**	**$ 2,744**	**$ 1,633**	**$ 1,743**	**$ 1,659**	**$ 2,137**	**$ 2,310**	**$ 12,227**
9								
10	**Prior Period (Over)Undercollection**	-	-	-	-	-	-	-
11								
12	**Subtotal Gas Costs, Working Capital & Under Collection**	$ 286,458	$ 170,543	$ 182,043	$ 173,217	$ 223,125	$ 241,221	$ 1,276,607
13								
14	**Bad Debt Rate**	0.0257	0.0257	0.0257	0.0257	0.0257	0.0257	-
15								
16	**Total Bad Debt Cost**	**$ 7,362**	**$ 4,383**	**$ 4,679**	**$ 4,452**	**$ 5,734**	**$ 6,199**	**$ 32,809**

Local Distribution Adjustment Charge Calculation

Reference

Residential Non Heating Rates - R-1

				Reference
Energy Efficiency Charge	$0.0184			Energy Efficiency page 1
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0184		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0000			Proposed Eighth Revised Page 88
Environmental Surcharge (ES)		0.0000		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0075		RLIAP page 1
LDAC		**$0.0259**	**per therm**	

Residential Heating Rates - R-3, R-4

				Reference
Energy Efficiency Charge	$0.0184			Energy Efficiency page 1
Demand Side Management Charge	0.0006			Conservation Charge
Conservation Charge (CCx)		$0.0190		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0000			Proposed Eighth Revised Page 88
Environmental Surcharge (ES)		0.0000		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0075		RLIAP page 1
LDAC		**$0.0265**	**per therm**	

Commercial/Industrial Low Annual Use Rates - G-41, G-51

				Reference
Energy Efficiency Charge	$0.0213			Energy Efficiency page 2
Demand Side Management Charge	0.0000			Conservation Charge
Conservation Charge (CCx)		$0.0213		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0000			Proposed Eighth Revised Page 88
Environmental Surcharge (ES)		0.0000		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Gas Restructuring Expense Factor (GREF)		0.0000		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0075		RLIAP page 1
LDAC		**$0.0288**	**per therm**	

Commercial/Industrial Medium Annual Use Rates - G-42, G-52

				Reference
Energy Efficiency Charge	$0.0213			Energy Efficiency page 2
Demand Side Management Charge	0.0000			Conservation Charge
Conservation Charge (CCx)		$0.0213		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0000			Proposed Eighth Revised Page 88
Environmental Surcharge (ES)		0.0000		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Gas Restructuring Expense Factor (GREF)		0.0000		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0075		
LDAC		**$0.0288**	**per therm**	

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-63

				Reference
Energy Efficiency Charge	$0.0213			Energy Efficiency page 2
Demand Side Management Charge	0.0000			Conservation Charge
Conservation Charge (CCx)		$0.0213		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0000			Proposed Eighth Revised Page 88
Environmental Surcharge (ES)		0.0000		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Gas Restructuring Expense Factor (GREF)		0.0000		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0075		
LDAC		**$0.0288**	**per therm**	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Residential Low Income Assistance Program (RLIAP)

Line		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 11.4600	$ 0.3356	$ 0.1950		
3	R-4 Rate at 40% of R-3	$ 4.5800	$ 0.1343	$ 0.0780		
4	Program Subsidy	$ 6.8800	$ 0.2013	$ 0.1170		
5	Average Annual Therms		572	203	775	
6						
7	Peak Period RLIAP Subsidy	$ 41.28	$ 115.18	$ 23.74	$ 180.20	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 11.4600	$ 0.3356	$ 0.1950		
11	R-4 Rate at 40% of R-3	$ 4.5800	$ 0.1343	$ 0.0780		
12	Program Subsidy	$ 6.8800	$ 0.2013	$ 0.1170		
13	Average Annual Therms		118	52	170	
14						
15	Off Peak Period RLIAP Subsidy	$ 41.28	$ 23.79	$ 6.09	$ 71.17	
16						
17	Estimated Annual Subsidy	$ 82.56	$ 138.98	$ 29.83	$ 251.37	
18						
19	Number of Estimated 2008/09 Participants				5,353	1/
20						
21	Annual Subsidy times Number of Particpants (Ln 17 * Ln 19)				$ 1,345,568	
22	Prior Year Ending Balance - RLIAP Page 2				(219,574)	
23	Estimated Annual Administrative Costs				8,650	
24	Total Program Costs				$ 1,134,644	
25						
26	Estimated weather normalized firm therms billed for					
27	the twelve months ended 10/31/09 sales and transportation				152,010,247	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0075**	

1/ Estimated number of participants for 2008-09 is based on the actual number participants as of June 2008, as provided in the RLIAP Quarterly Report filed on July 31, 2008.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
NOVEMBER 2007 THROUGH OCTOBER 2008
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

											(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (247,526)	$ (269,918)	$ (301,630)	$ (321,550)	$ (291,121)	$ (251,241)	$ (184,340)	$ (146,063)	$ (133,528)	$ (118,545)	$ (67,268)	$ (18,317)	$ (247,526)
4														
5	Add: Actual Costs	29,423	77,528	105,651	155,386	152,985	155,353	91,659	48,906	42,672	77,343	77,689	87,605	1,102,201
6														
7	Less: Collected Revenue	(58,875)	(107,466)	(123,730)	(123,502)	(111,805)	(87,514)	(52,682)	(35,798)	(27,155)	(25,673)	(28,562)	(38,358)	(821,120)
8														
9	Per Settlement in Order 24,824 issued 2/29/08												(250,000)	(250,000)
10														
11	Add: Administrative and Start Up Costs	8,650	-	-	-	-	-	-	-	-	-	-	-	**8,650**
12														
13	Ending Balance Pre-Interest	$ (268,328)	$ (299,856)	$ (319,708)	$ (289,666)	$ (249,941)	$ (183,402)	$ (145,363)	$ (132,955)	$ (118,011)	$ (66,874)	$ (18,141)	$ (219,070)	**$ (207,795)**
14														
15	Month's Average Balance	$ (257,927)	$ (284,887)	$ (310,669)	$ (305,608)	$ (270,531)	$ (217,322)	$ (164,851)	$ (139,509)	$ (125,770)	$ (92,710)	$ (42,705)	$ (118,694)	
16														
17	Interest Rate	7.50%	7.33%	6.98%	6.00%	5.66%	5.25%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
18														
19	Interest Applied	$ (1,590)	$ (1,774)	$ (1,842)	$ (1,455)	$ (1,300)	$ (938)	$ (700)	$ (573)	$ (534)	$ (394)	$ (175)	$ (504)	**(11,779)**
20														
21	Ending Balance	**$ (269,918)**	**$ (301,630)**	**$ (321,550)**	**$ (291,121)**	**$ (251,241)**	**$ (184,340)**	**$ (146,063)**	**$ (133,528)**	**$ (118,545)**	**$ (67,268)**	**$ (18,317)**	**$ (219,574)**	**$ (219,574)**

Conservation Charge (CC) Factor Calculation

Conservation Charge Factors for Residential Customers (CCres)

DSM Expenses	$0	Backup Page 4 Line 7
Residential Lost Margins	$29,884	Backup Page 5 Line 5
Residential Conservation Reconciliation Adjustment (CCRres)	4,415	Backup Page 2 Line 11
Total Rate Case Expense Recoverable	$34,298	
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	58,718,919	
Conservation Charge Factor for Residential Customers (CCres)		**$0.0006**

Conservation Charge Factors for Commercial Customers (CCcomm)

DSM Expenses	$0	Backup Page 4 Line 24
Commercial Lost Margins	$799	Backup Page 5 Line 16
Commercial Conservation Reconciliation Adjustment (CCRcomm)	(3,106)	Backup Page 2 Line 28
Total Rate Case Expense Recoverable	($2,307)	
Forecasted Annual Throughput Volumes for Commercial Customer (A:VOLcomm)	92,181,379	
Conservation Charge Factor for Commercial Customers (CCres)		**$0.0000**

2007/2008 EnergyNorth Conservation Charge Reconciliation

Line No.		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
		2007	2007	2007	2008	2008	2008	2008	2008	2008	2008	2008	2008	
	Domestic Heating:	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
1	**Beginning balance**	2,743	$4,007	$5,479	$6,074	$6,914	$7,026	$6,905	$6,234	$5,807	$5,261	$4,694	$4,245	$2,743
2	Therms sold	1,486,017	3,713,088	8,692,419	9,503,457	9,539,936	8,562,340	6,448,937	3,376,587	1,777,499	1,286,373	1,152,032	1,240,508	56,779,193
3	Surcharge (Tariff Pg. 91)	(0.0006)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0005)	
4	Revenue collected	(892)	(1,857)	(4,346)	(4,752)	(4,770)	(4,281)	(3,224)	(1,688)	(889)	(643)	(576)	(620)	(28,538)
5	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Lost net rev (Pg 4 Ln.5)	2,133	3,299	4,906	5,554	4,847	4,128	2,525	1,237	320	55	109	772	29,884
7	Under/(over)	1,242	1,442	560	802	77	(154)	(700)	(451)	(569)	(588)	(467)	152	1,345
8	Pre-interest ending balance	3,985	5,449	6,038	6,876	6,991	6,872	6,205	5,782	5,238	4,673	4,226	4,397	4,089
9	Average monthly balance	3,364	4,728	5,758	6,475	6,952	6,949	6,555	6,008	5,523	4,967	4,460	4,321	3,416
10	Interest for month	22	30	35	38	35	33	29	25	23	21	19	18	326
11	**Month-end balance**	4,007	5,479	6,074	6,914	7,026	6,905	6,234	5,807	5,261	4,694	4,245	4,415	4,415
12	Interest rate	7.75%	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%	5.00%	5.00%	5.00%	5.00%	5.00%	5.96%
13														
14		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
15		2007	2007	2007	2008	2008	2008	2008	2008	2008	2008	2008	2008	
16	**Commercial Heating:**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
17	**Beginning balance**	(3,707)	($3,682)	($3,615)	($3,502)	($3,368)	($3,254)	($3,160)	($3,107)	($3,091)	($3,095)	($3,106)	($3,115)	($3,707)
18	Therms sold	3,880,671	6,032,970	11,085,314	13,278,434	13,202,955	12,021,866	9,649,489	6,292,406	4,781,718	3,681,187	3,334,902	3,551,921	90,793,833
19	Surcharge (Tariff Pg. 91)	-	-	-	-	-	-	-	-	-	-	-	-	
20	Revenue collected	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Lost net rev (Pg 4 Ln.16)	49	90	134	154	130	109	67	29	9	2	4	22	799
23			-											-
24	Under/(over)	49	90	134	154	130	109	67	29	9	2	4	22	799
25	Pre-interest ending balance	(3,658)	(3,592)	(3,480)	(3,348)	(3,238)	(3,145)	(3,093)	(3,078)	(3,082)	(3,093)	(3,102)	(3,093)	(2,908)
26	Average monthly balance	(3,683)	(3,637)	(3,548)	(3,425)	(3,303)	(3,200)	(3,126)	(3,092)	(3,087)	(3,094)	(3,104)	(3,104)	(3,308)
27	Interest for month	(24)	(23)	(22)	(20)	(17)	(15)	(14)	(13)	(13)	(13)	(13)	(13)	(198)
28	**Month-end balance**	(3,682)	(3,615)	(3,502)	(3,368)	(3,254)	(3,160)	(3,107)	(3,091)	(3,095)	(3,106)	(3,115)	(3,106)	(3,106)
29	Interest rate	7.75%	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%	5.00%	5.00%	5.00%	5.00%	5.00%	
30														
31		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
32		2007	2007	2007	2008	2008	2008	2008	2008	2008	2008	2008	2008	
33	**TOTAL**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
34	**Beginning balance**	($964)	$325	$1,864	$2,572	$3,545	$3,771	$3,745	$3,127	$2,716	$2,166	$1,587	$1,130	($964)
35	Therms sold	5,366,688	9,746,058	19,777,733	22,781,891	22,742,891	20,584,206	16,098,426	9,668,993	6,559,217	4,967,560	4,486,934	4,792,429	147,573,026
36	Revenue collected	(892)	(1,857)	(4,346)	(4,752)	(4,770)	(4,281)	(3,224)	(1,688)	(889)	(643)	(576)	(620)	(28,538)
37	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Lost net revenues	2,182	3,389	5,041	5,708	4,978	4,237	2,591	1,266	328	57	113	794	30,683
39	Under/(over)	1,290	1,532	694	956	208	(44)	(633)	(423)	(560)	(586)	(463)	174	2,144
40	Pre-interest ending balance	327	1,857	2,558	3,528	3,753	3,727	3,112	2,704	2,156	1,580	1,124	1,304	1,181
41	Interest for month	(2)	7	14	18	18	18	15	12	10	8	6	5	128
42	**Month-end balance**	325	1,864	2,572	3,545	3,771	3,745	3,127	2,716	2,166	1,587	1,130	1,309	1,309
43	Interest rate	7.75%	7.50%	7.33%	6.98%	6.00%	5.66%	5.24%	5.00%	5.00%	5.00%	5.00%	5.00%	

2005/2006 EnergyNorth Conservation Charge Reconciliation

Actual Throughput

Line No.		2007 OCT	2007 NOV	2007 DEC	2008 JAN	2008 FEB	2008 MAR	2008 APR	2008 MAY	2008 JUN	2008 JUL	2008 AUG	2008 SEP	TOTAL
	Domestic Heating:													
1	Therms sold - actual	1,486,017	3,713,088	8,692,419	9,503,457	9,539,936	8,562,340	6,448,937	3,376,587	1,777,499	1,286,373	1,152,032	1,240,508	56,779,193
2	Surcharge (Tariff Pg 61)	($0.0006)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	
3	Revenue - actual	(892)	(1,857)	(4,346)	(4,752)	(4,770)	(4,281)	(3,224)	(1,688)	(889)	(643)	(576)	(620)	(28,538)
4														
5														
6														
7	**Commercial Heating:**													
8	Therms sold - actual	3,880,671	6,032,970	11,085,314	13,278,434	13,202,955	12,021,866	9,649,489	6,292,406	4,781,718	3,681,187	3,334,902	3,551,921	90,793,833
9	Surcharge (Tariff Pg 61)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
10	Revenue - actual	-	-	-	-	-	-	-	-	-	-	-	-	-
11														
12														
13	**Total:**													
14	Therms sold - actual	5,366,688	9,746,058	19,777,733	22,781,891	22,742,891	20,584,206	16,098,426	9,668,993	6,559,217	4,967,560	4,486,934	4,792,429	147,573,026
15	Revenue - actual	(892)	(1,857)	(4,346)	(4,752)	(4,770)	(4,281)	(3,224)	(1,688)	(889)	(643)	(576)	(620)	(28,538)

2005/2006 EnergyNorth Conservation Charge Reconciliation

Actual Expenses

Line No.		2007 OCT	2007 NOV	2007 DEC	2008 JAN	2008 FEB	2008 MAR	2008 APR	2008 MAY	2008 JUN	2008 JUL	2008 AUG	2008 SEP	TOTAL
	Residential Expenses Incurred													
1	Administrative	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Total Residential Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9														
10														
11	**Commercial Expenses Incurred**													
12														
13	Administrative:													
14	Delivery Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Photocopies	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Telephone	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Travel	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Legal	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
23														
24	Total Commercial Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-

2006/2007 ENERGYNORTH LOST MARGIN SUMMARY

Line No.		2007 Oct	2007 Nov	2007 Dec	2008 Jan	2008 Feb	2008 Mar	2008 Apr	2008 May	2008 June	2008 July	2008 Aug	2008 Sep	TOTAL
	Residential Heating													
	fiscal 2008													
1	Lost Vol Therms (Pg 6 Ln 29)	21,873	33,824	50,305	56,949	49,701	42,323	25,886	12,684	3,279	561	1,079	6,946	305,409
2	Tailblock Rate	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1767	$0.1950	
3	Margin	$3,743	$5,787	$8,607	$9,744	$8,504	$7,242	$4,429	$2,170	$561	$96	$191	$1,354	$52,428
4	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	
5	Lost Margin	$2,133	$3,299	$4,906	$5,554	$4,847	$4,128	$2,525	$1,237	$320	$55	$109	$772	$29,884
6														
7														
8														
9	**Commercial and Industrial:**													
10														
11	**fiscal 2008**													
12	Lost Vol Therms (Pg 5 Ln 53)	551	859	1,284	1,467	1,245	1,044	639	324	97	23	46	217	7,795
13	Tailblock Rate	$0.1551	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1551	$0.1551	$0.1551	$0.1601	$0.1767	
14	Margin	$86	$158	$236	$270	$229	$192	$117	$50	$15	$4	$7	$38	$1,402
15	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%
16	Lost Margin	$49	$90	$134	$154	$130	$109	$67	$29	$9	$2	$4	$22	$799
17														
18														
19	**Total**													
20														
21	**fiscal 2008**													
22	Lost Volume Therms	22,425	34,683	51,588	58,416	50,946	43,367	26,524	13,008	3,375	584	1,124	7,163	
23	Tailblock Rate													
24	Margin	$3,828	$5,945	$8,843	$10,014	$8,733	$7,433	$4,546	$2,220	$576	$100	$198	$1,393	$53,829
25	recovery rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%
26	recoverable portion	$2,182	$3,389	$5,041	$5,708	$4,978	$4,237	$2,591	$1,266	$328	$57	$113	$794	$30,683

ENERGYNORTH 2007/2008 LOST MARGIN CALCULATION BACKUP

Line No.	**Actual tailblock margin**	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	New Rate Eff 8/24/08 Aug-08	Sep-08	
1	**Domestic Heating**	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1767	0.1950	
2														
3	**Commercial Heating**	0.1551	0.1838	0.1838	0.1838	0.1838	0.1838	0.1838	0.1551	0.1551	0.1551	0.1601	0.1767	
4														
5	**Normal heating degree days (calendar):**													
6		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total
7														
8	Heating Degree Days	507	784	1,166	1,320	1,152	981	600	294	76	13	25	161	7,079
9														
10	Percent of Total	7.16%	11.08%	16.47%	18.65%	16.27%	13.86%	8.48%	4.15%	1.07%	0.18%	0.35%	2.27%	100.00%
11														

Residential Heating

Line No.		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	annual load	F Y 97	FY98	FY99	FY00	FY01
12																				
13																				
14								Therms								Pg 8 Ln32	Pg 7 Ln31	Pg 6 Ln14		
15	**program year 2008**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	annual load	F Y 97	FY98	FY99	FY00	FY01
16	**DH** - therm savings fiscal															Savings	Savings	Savings	Savings	Savings
17	Oct-06	1,105	1,709	2,542	2,877	2,511	2,138	1,308	641	166	28	54	351	15,432	15,432	8,616	6,816	-	0	0
18	Nov-06	1,178	1,822	2,710	3,067	2,677	2,280	1,394	683	177	30	58	374	16,450	16,450	3,455	12,996	-	0	0
19	Dec-06	1,852	2,865	4,260	4,823	4,209	3,584	2,192	1,074	278	47	91	588	25,866	25,866	4,342	15,945	5,579	0	0
20	Jan-07	1,849	2,859	4,253	4,814	4,201	3,578	2,188	1,072	277	47	91	587	25,818	25,818	4,088	6,134	15,596	0	0
21	Feb-07	2,605	4,028	5,991	6,782	5,919	5,040	3,083	1,511	390	67	128	827	36,373	36,373	9,277	12,457	14,639	0	0
22	Mar-07	2,259	3,494	5,196	5,882	5,134	4,372	2,674	1,310	339	58	111	717	31,547	31,547	8,055	14,524	8,969	0	0
23	Apr-07	2,583	3,993	5,939	6,724	5,868	4,997	3,056	1,498	387	66	127	820	36,059	36,059	10,465	17,113	8,481	0	0
24	May-07	1,191	1,842	2,740	3,101	2,707	2,305	1,410	691	179	31	59	378	16,633	16,633	11,922	4,711	-	0	0
25	Jun-07	2,346	3,628	5,396	6,109	5,331	4,540	2,777	1,361	352	60	116	745	32,762	32,762	23,809	7,258	1,695	0	0
26	Jul-07	1,131	1,750	2,602	2,946	2,571	2,189	1,339	656	170	29	56	359	15,798	15,798	12,412	3,386	-	0	0
27	Aug-07	1,280	1,980	2,944	3,333	2,909	2,477	1,515	742	192	33	63	407	17,875	17,875	12,514	1,331	4,030	0	0
28	Sep-07	2,492	3,854	5,732	6,489	5,663	4,822	2,950	1,445	374	64	123	791	34,800	34,800	28,758	5,981	61	0	0
29	totals	21,873	33,824	50,305	56,949	49,701	42,323	25,886	12,684	3,279	561	1,079	6,946	305,409	305,409	137,710	108,649	59,050	-	-
30																				
31	Rate	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1767	0.1950							
32	Margin	3,743	5,787	8,607	9,744	8,504	7,242	4,429	2,170	561	96	191	1,354	52,428						
33	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
34		2,133	3,299	4,906	5,554	4,847	4,128	2,525	1,237	320	55	109	772	29,884						
35																				

Commercial Heating

Line No.		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	Total	F Y 97	FY98	FY99	FY00	FY01
36																				
37																				
38								Therms								Pg 8 Ln49	Pg 7 Ln48			
39	**program year 2008**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	Total	F Y 97	FY98	FY99	FY00	FY01
40	**CH** - therm savings															Savings	Savings	Savings	Savings	Savings
41	Oct-06	13	21	31	36	30	25	15	8	2	1	1	5	189	189	-	189	0	0	0
42	Nov-06	40	62	93	107	91	76	46	24	7	2	3	16	567	567	378	189	0	0	0
43	Dec-06	84	131	196	224	190	159	97	49	15	3	7	33	1,189	1,189	439	750	0	0	0
44	Jan-07	67	104	156	178	151	127	77	39	12	3	6	26	945	945	189	756	0	0	0
45	Feb-07	28	44	66	75	64	53	33	17	5	1	2	11	399	399	189	210	0	0	0
46	Mar-07	67	104	156	178	151	127	77	39	12	3	6	26	945	945	378	567	0	0	0
47	Apr-07	13	21	31	36	30	25	15	8	2	1	1	5	189	189	-	189	0	0	0
48	May-07	27	42	62	71	60	51	31	16	5	1	2	11	378	378	-	378	0	0	0
49	Jun-07	89	138	207	236	201	168	103	52	16	4	7	35	1,256	1,256	567	689	0	0	0
50	Jul-07	39	60	90	103	88	74	45	23	7	2	3	15	549	549	549	-	0	0	0
51	Aug-07	13	21	31	36	30	25	15	8	2	1	1	5	189	189	189	-	0	0	0
52	Sep-07	71	110	165	188	160	134	82	42	12	3	6	28	1,000	1,000	-	1,000	0	0	0
53	totals	551	859	1,284	1,467	1,245	1,044	639	324	97	23	46	217	7,795	7,795	2,878	4,917	-	-	-
54																				
55	Rate	$0.1551	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1551	$0.1551	$0.1551	$0.1601	$0.1767							
56	Margin	$86	$158	$236	$270	$229	$192	$117	$50	$15	$4	$7	$38	$1,402						
57	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
58	Total Recovery	$49	$90	$134	$154	$130	$109	$67	$29	$9	$2	$4	$22	$799						

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EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential Non Heating and Heating Classes
November 1, 2008 - October 31, 2009
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures		Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Monthly Federal Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Residential Therm Sales	Residential Therm Sales	# of Days
						Residential	Low-Income								
May 08	**Actual**	**(220,162)**	($0.0133)	(46,065)	86,349	61,899	303	(204,025)	(212,093)	**5.00%**	(901)	(204,925)	3,634,335	3,463,518	31
June 08	Forecast	(204,925)	($0.0133)	(24,573)	86,349	36,381	131	(192,986)	(198,956)	5.00%	(818)	(193,804)	2,377,283	1,847,599	30
July 08	Forecast	(193,804)	($0.0133)	(20,128)	86,349	0	0	(127,584)	(160,694)	5.00%	(682)	(128,266)	1,513,415	0	31
August 08	Forecast	(128,266)	($0.0133)	(16,670)	86,349	0	0	(58,587)	(93,426)	5.00%	(397)	(58,984)	1,253,369	0	31
September 08	Forecast	(58,984)	($0.0133)	(19,055)	86,349	0	0	8,310	(25,337)	5.00%	(104)	8,206	1,432,714	0	30
October 08	Forecast	8,206	($0.0133)	(30,289)	86,349	0	0	64,266	36,236	5.00%	154	64,420	2,277,336	0	31
November 08	Forecast	64,420	($0.0184)	(75,790)	86,830	0	0	75,460	69,940	5.00%	287	75,747	4,123,508	0	30
December 08	Forecast	75,747	($0.0184)	(154,079)	86,830	0	0	8,498	42,123	5.00%	179	8,677	8,382,988	0	31
January 09	Forecast	8,677	($0.0184)	(181,130)	86,830	0	0	(85,622)	(38,473)	5.00%	(163)	(85,786)	9,854,722	0	31
February 09	Forecast	(85,786)	($0.0184)	(189,368)	86,830	0	0	(188,324)	(137,055)	5.00%	(526)	(188,849)	10,302,951	0	28
March 09	Forecast	(188,849)	($0.0184)	(160,907)	86,830	0	0	(262,927)	(225,888)	5.00%	(959)	(263,886)	8,754,478	0	31
April 09	Forecast	(263,886)	($0.0184)	(124,605)	86,830	0	0	(301,661)	(282,773)	5.00%	(1,162)	(302,823)	6,779,391	0	30
May 09	Forecast	(302,823)	($0.0184)	(69,313)	86,830	0	0	(285,305)	(294,064)	5.00%	(1,249)	(286,554)	3,771,083	0	31
June 09	Forecast	(286,554)	($0.0184)	(38,396)	86,830	0	0	(238,119)	(262,337)	5.00%	(1,078)	(239,197)	2,088,995	0	30
July 09	Forecast	(239,197)	($0.0184)	(25,903)	86,830	0	0	(178,270)	(208,734)	5.00%	(886)	(179,157)	1,409,310	0	31
August 09	Forecast	(179,157)	($0.0184)	(22,918)	86,830	0	0	(115,244)	(147,201)	5.00%	(625)	(115,869)	1,246,888	0	31
September 09	Forecast	(115,869)	($0.0184)	(24,633)	86,830	0	0	(53,672)	(84,771)	5.00%	(348)	(54,021)	1,340,217	0	30
October 09	Forecast	(54,021)	($0.0184)	(32,612)	86,830	0	0	197	(26,912)	5.00%	(114)	83	1,774,338	0	31
12 Month Totals				(1,099,655)	1,041,963	0					(6,645)		59,828,869	0	

Residential Non Heating Therm Sales	**1,109,950**	1%
Residential Heating Therm Sales	**58,718,919**	39%
C&I Therm Sales	**92,181,379**	61%
Total Therms	**152,010,247**	100%

		2008-09
Low-Income Program Budget	**$**	**442,864**
Other Refund		-
Total Shared Budget	**$**	**442,864**
Residential Program Budget	**$**	**782,128**
Residential Program Incentive		**85,530**
Total Residential Program Budget	**$**	**867,658**
Commercial/Industrial Program Budget	**$**	**1,426,799**
Commercial/Industrial Program Incentive		**107,922**
Total Commercial/Industrial Program Budget	**$**	**1,534,720**
Total Program Budget	**$**	**2,845,243**
Shared Expenses Allocation to Residential	$	174,304
Shared Expenses Allocation to C&I		268,560
Total Allocated Shared Expenses	**$**	**442,864**
Total Residential (including allocation of Shared Budget)	$	1,041,963
Total C&I (including allocation of Shared Budget)		1,803,280
Total Budget	**$**	**2,845,243**

Estimated Residential Nonheating Conservation Charge Effective November 2008 - October 2009		
Beginning Balance	$	64,420
Program Budget		1,041,963
Projected Interest		(6,645)
Projected Budget with Interest	$	1,099,737
Total Charges	**$**	**1,106,383**
Projected Therm Sales		**59,828,869**
Residential Rate		**$0.0185**
Total Charges with Interest	**$**	**1,099,737**
Projected Therm Sales		**59,828,869**
Residential Rate		**$0.0184**

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EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2008 - October 31, 2009
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Com-Ind	Actual DSM Expenditures Low-Income	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Fed Reserve Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Commercial/ Industrial Therm Sales	Commercial/ Industrial Therm Sales	# of Days
May 08	Actual	**(559,861)**	**($0.0047)**	(29,574)	150,273	32,338	401	(556,695)	(558,278)	**5.00%**	(2,371)	(559,066)	5,734,006	6,292,406	31
June 08	Forecast	(559,066)	($0.0047)	(22,474)	150,273	220,726	174	(360,640)	(459,853)	5.00%	(1,890)	(362,530)	4,880,050	4,781,718	30
July 08	Forecast	(362,530)	($0.0047)	(17,890)	150,273	0	0	(230,147)	(296,339)	5.00%	(1,258)	(231,405)	3,806,307	0	31
August 08	Forecast	(231,405)	($0.0047)	(16,323)	150,273	0	0	(97,455)	(164,430)	5.00%	(698)	(98,153)	3,473,080	0	31
September 08	Forecast	(98,153)	($0.0047)	(17,981)	150,273	0	0	34,139	(32,007)	5.00%	(132)	34,007	3,825,702	0	30
October 08	Forecast	34,007	($0.0047)	(22,488)	150,273	0	0	161,793	97,900	5.00%	416	162,209	4,784,631	0	31
November 08	Forecast	162,209	($0.0213)	(135,007)	150,273	0	0	177,475	169,842	5.00%	698	178,173	6,338,363	0	30
December 08	Forecast	178,173	($0.0213)	(224,297)	150,273	0	0	104,149	141,161	5.00%	599	104,749	10,530,359	0	31
January 09	Forecast	104,749	($0.0213)	(285,134)	150,273	0	0	(30,112)	37,318	5.00%	158	(29,954)	13,386,584	0	31
February 09	Forecast	(29,954)	($0.0213)	(294,265)	150,273	0	0	(173,945)	(101,949)	5.00%	(391)	(174,336)	13,815,243	0	28
March 09	Forecast	(174,336)	($0.0213)	(265,881)	150,273	0	0	(289,944)	(232,140)	5.00%	(986)	(290,930)	12,482,657	0	31
April 09	Forecast	(290,930)	($0.0213)	(217,225)	150,273	0	0	(357,881)	(324,406)	5.00%	(1,333)	(359,215)	10,198,349	0	30
May 09	Forecast	(359,215)	($0.0213)	(123,871)	150,273	0	0	(332,812)	(346,013)	5.00%	(1,469)	(334,282)	5,815,550	0	31
June 09	Forecast	(334,282)	($0.0213)	(98,625)	150,273	0	0	(282,633)	(308,457)	5.00%	(1,268)	(283,901)	4,630,286	0	30
July 09	Forecast	(283,901)	($0.0213)	(75,318)	150,273	0	0	(208,946)	(246,423)	5.00%	(1,046)	(209,992)	3,536,049	0	31
August 09	Forecast	(209,992)	($0.0213)	(75,190)	150,273	0	0	(134,909)	(172,450)	5.00%	(732)	(135,641)	3,530,053	0	31
September 09	Forecast	(135,641)	($0.0213)	(81,243)	150,273	0	0	(66,611)	(101,126)	5.00%	(416)	(67,026)	3,814,243	0	30
October 09	Forecast	(67,026)	($0.0213)	(87,408)	150,273	0	0	(4,161)	(35,594)	5.00%	(151)	(4,312)	4,103,643	0	31
Totals				($1,963,464)	$1,803,280	$0					($6,337)		92,181,379	0	

Estimated C & I Conservation Charge Effective November 2008 - October 2009	
Beginning Balance	$162,209
Program Budget	1,803,280.02
Projected Interest	(6,336.63)
Program Budget with Interest	$1,959,152
Total Charges	**$1,965,489**
Projected Therm Sales	**92,181,379**
C&I Rate	$0.0213
Total Charges with Interest	**$1,959,152**
Projected Therm Sales	**92,181,379**
Com/Ind Rate	**$0.0213**
Com/Ind Rate from Prior Programs (1)	**$0.0000**
Combined Com/Ind Rate	**$0.0213**

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EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2008 - October 31, 2009
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures				Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Therm Sales	# of Days
						Residential	Com-Ind	Low-Income	Total								
May 08	Actual	(780,023)	n/a	(75,639)	236,622	61,899	32,338	704	94,941	(760,720)	(770,371)	**5.00%**	(3,271)	(763,991)	9,368,341	9,755,924	31
June 08	Forecast	(763,991)	n/a	(47,047)	236,622	36,381	220,726	305	257,412	(553,627)	(658,809)	5.00%	(2,707)	(556,334)	7,257,333	6,629,317	30
July 08	Forecast	(556,334)	n/a	(38,018)	236,622	0	0	0	0	(357,730)	(457,032)	5.00%	(1,941)	(359,671)	5,319,722	0	31
August 08	Forecast	(359,671)	n/a	(32,993)	236,622	0	0	0	0	(156,042)	(257,857)	5.00%	(1,095)	(157,137)	4,726,448	0	31
September 08	Forecast	(157,137)	n/a	(37,036)	236,622	0	0	0	0	42,449	(57,344)	5.00%	(236)	42,213	5,258,416	0	30
October 08	Forecast	42,213	n/a	(52,777)	236,622	0	0	0	0	226,059	134,136	5.00%	570	226,628	7,061,967	0	31
November 08	Forecast	226,628	n/a	(210,797)	237,104	0	0	0	0	252,935	239,782	5.00%	985	253,920	10,461,871	0	30
December 08	Forecast	253,920	n/a	(378,376)	237,104	0	0	0	0	112,648	183,284	5.00%	778	113,426	18,913,347	0	31
January 09	Forecast	113,426	n/a	(466,264)	237,104	0	0	0	0	(115,734)	(1,154)	5.00%	(5)	(115,739)	23,241,305	0	31
February 09	Forecast	(115,739)	n/a	(483,633)	237,104	0	0	0	0	(362,269)	(239,004)	5.00%	(917)	(363,186)	24,118,194	0	28
March 09	Forecast	(363,186)	n/a	(426,788)	237,104	0	0	0	0	(552,870)	(458,028)	5.00%	(1,945)	(554,815)	21,237,135	0	31
April 09	Forecast	(554,815)	n/a	(341,830)	237,104	0	0	0	0	(659,542)	(607,179)	5.00%	(2,495)	(662,037)	16,977,740	0	30
May 09	Forecast	(662,037)	n/a	(193,184)	237,104	0	0	0	0	(618,117)	(640,077)	5.00%	(2,718)	(620,835)	9,586,633	0	31
June 09	Forecast	(620,835)	n/a	(137,021)	237,104	0	0	0	0	(520,753)	(570,794)	5.00%	(2,346)	(523,098)	6,719,280	0	30
July 09	Forecast	(523,098)	n/a	(101,221)	237,104	0	0	0	0	(387,216)	(455,157)	5.00%	(1,933)	(389,149)	4,945,359	0	31
August 09	Forecast	(389,149)	n/a	(98,108)	237,104	0	0	0	0	(250,153)	(319,651)	5.00%	(1,357)	(251,510)	4,776,941	0	31
September 09	Forecast	(251,510)	n/a	(105,876)	237,104	0	0	0	0	(120,283)	(185,897)	5.00%	(764)	(121,047)	5,154,460	0	30
October 09	Forecast	(121,047)	n/a	(120,020)	237,104	0	0	0	0	(3,964)	(62,505)	5.00%	(265)	(4,229)	5,877,982	0	31
Totals				($3,063,119)	$2,845,243	$0									152,010,247	0	

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 2008 - October 2009	
Beginning Balance	$226,628
Program Budget	2,845,242.72
Projected Interest	(12,981.74)
Program Budget with Interest	$3,058,889
Total Charges	**$3,058,889**

DSM/MT Program Budget & Goals: Program Year Three (May 1, 2008 - April 30, 2009)

NH Program Budget & Goals	NH Services	NH Vendor Support	NH Company Admin	NH Communication	NH Trade Ally Training	NH Evaluation & Reporting	NH Other	NH Budget	NH Program Goals	
Residential										
Low Income	$278,598	$77,837	$54,494	$6,223	$2,849	$4,672	$18,191	$442,864	160	Participants
Residential Weatherization	$42,344	$7,763	$4,940	$20,586	$10,395	$3,529	$0	$89,557	45	Rebates
Residential High Efficiency Heating	$172,500	$7,500	$21,043	$45,093	$10,012	$15,031	$0	$271,179	500	Audits
Residential Water Heating	$45,000	$3,864	$5,031	$20,781	$1,438	$5,594	$0	$81,708	150	Windows
ES Windows	$30,000	$6,327	$4,026	$18,628	$1,150	$2,876	$0	$63,008	300	Rebates
Advanced Residential Controls	$10,000	$7,185	$1,942	$14,162	$555	$1,387	$0	$35,231	325	New Users
ES Homes	$39,337	$7,212	$4,589	$9,834	$1,311	$3,278	$0	$65,561	55	Thermostats
Energy Analysis: Internet Audit	$18,837	$2,416	$2,868	$16,146	$820	$2,049	$0	$43,136	600	Rebates
Residential Conservation Services	$58,356	$5,772	$3,673	$14,985	$1,049	$2,623	$0	$86,459	200	Participants
Building Practices and Demo	$27,775	$5,092	$3,240	$6,944	$926	$2,315	$0	$46,291	12	
Residential Subtotal	$722,746	$130,968	$105,848	$173,381	$30,505	$43,354	$18,191	**$1,224,992**	2,347	
Commercial & Industrial										
Comm Energy Efficiency Program	$ 267,856	$ 81,904	$ 30,049	$ 117,824	$ 5,710	$ 39,275	$ -	$542,617	84	Participants
Multifamily Housing Program	$ 74,520	$ 35,000	$ 20,820	$ 44,613	$ 5,948	$ 14,871	$ -	$195,773	3	Projects
Comm High Efficiency Heating	$ 99,600	$ 1,500	$ 161	$ 345	$ 5,642	$ 14,556	$ -	$121,803	116	Rebates
Economic Redevelopment	$ 240,405	$ 7,950	$ 19,751	$ 42,324	$ 5,643	$ 14,108	$ -	$330,182	210	New Users
Building Practices and Demo	$ 160,150	$ 24,000	$ 7,519	$ 16,113	$ 2,148	$ 5,371	$ -	$215,301	21	
Energy Analysis: Internet Audit	$ 12,673	$ 2,323	$ 1,479	$ 3,168	$ 422	$ 1,056	$ -	$21,122	2	
Commercial Total								**$1,426,799**		
Total	**$915,075**	**$281,318**	**$220,500**	**$120,330**	**$26,250**	**$36,750**	**$27,278**	**$2,651,791**		

00000121

Exhibit-C: KeySpan Energy Delivery - NH DSM/MT Program Year Two (2007-2008): Shareholder Incentive Calculation - August 27, 2008

	*		*					*					
Program	**Expenditures (Budget) for Program Year 2**		**Design Goal for PY 1**		**Projected Lifetime Therms Savings[1]**	**Actual Lifetime Therm Savings[2]**	**Actual LTT/Projected LTT**	**Projected TRC[3]**	**Actual TRC[4]**	**Actual TRC/Projected TRC**	**Lifetime Savings Incentive**	**Cost-effectiveness Incentive**	**Actual Pre Tax Design Incentive**
Residential													
Low Income	$	402,144	140	Participants	971,208	1,463,749	1.507	2.04	2.59	1.27			
Residential Weatherization	$	53,041	60	Rebates	529,920	600,576	1.133	4.38	4.94	1.13			
Residential High Efficiency Heating	$	237,765	500	Rebates	1,650,000	1,766,820	1.071	5.23	5.47	1.05			
Residential High Efficiency Water Heating	$	45,550	105	Rebates	160,650	256,580	1.597	2.57	2.62	1.02			
Energy Star Windows	$	49,519	3,000	Rebates	235,515	183,620	0.780	3.08	3.44	1.12			
Energy Star Thermostats	$	29,470	460	Rebates	345,000	216,040	0.626	9.41	10.93	1.16			
Energy Star Homes	$	48,154	75	Participants	510,000	340,000	0.667	4.41	2.98	0.67			
Energy Analysis: Internet Audit Guide	$	27,301	600	New Users									
Residential Technology Demonstration	$	44,087	2	Projects									
Residential Conservation Services	$	40,311	200	Participants									
Total	$	977,340	5,142		4,402,293	4,827,385	1.097	3.01	3.29	1.0913	$ 42,869	$ 42,661	$ 85,530
C&I and Mutifamily													
Commercial Energy Efficiency Program	$	310,109	84	Participants	3,421,958	11,895,379	3.476	5.51	7.41	1.34			
Multifamily Housing	$	71,289	21	Participants	1,205,228	5,567,005	4.619	11.36	20.55	1.81			
Commercial High Efficiency Heating	$	82,696	116	Rebates	874,380	638,900	0.731	8.03	7.33	0.91			
Economic Redevelopment	$	124,044	3	Projects	523,500	174,500	0.333	2.57	4.31	1.68			
Commercial Building Practices & Tecnology Demonstration	$	41,348	2	Projects	690,464	345,232	0.500	8.92	12.97	1.45			
C&I Energy Analysis Internet Audit	$	20,674	210	New Users									
Total - C&I and Multifamily	$	650,160	436		6,715,530	18,621,016	2.773	4.33	5.96	1.38	$ 72,111	$ 35,811	$ 107,922
Total of Column		$1,627,500										**TOTAL Incentive**	**$ 193,452**

Notes:

This shareholder incentive calculation is based on the methodology described in NH PUC Order 24,109 of December 31, 2002.

Threshold: KeySpan must achieve a minimum "threshold" performance before being eligible to earn an incentive

For the cost-effectiveness component, KeySpan must achieve an actual year-end TRC of 1.0 before any incentive can be earned

Once the threshold is achieved, the earned incentive will be on a sliding scale from 0% to 12%

Assumptions:

Design Target Incentive = 8%

Incentive Calculation Formula: $Incentive_{res} = Expenditures_{RES} \times \{[4\% \times (TRC_{Actual} / TRC_{Projected})] + [4\% \times Lifetime\ Therm\ Savings_{Actual} / Lifetime\ Therm\ Savings_{Projected})]\}$

Plus

$Incentive_{C\&I} = Expenditures_{C\&I} \times \{[4\% \times (TRC_{Actual} / TRC_{Projected})] + [4\% \times Lifetime\ Therm\ Savings_{Actual} / Lifetime\ Therm\ Savings_{Projected})]\}$

[1]Per a September 9, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the projected lifetime therm savings for each KED New Hampshire natural gas energy efficiency program and the source of the projected benefit/cost ratios by program is KeySpan's response to NH PUC Staff Data Request 2-31, Pages 3 to 6, Docket DG 04-152, filed by attorney Steven V. Camerino on November 22, 2004).

[2]From the updated Exhibit G showing actual Program Year 1 results.

[3,4,5] Per a September 20, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the Lifetime savings and Cost Effectiveness incentive calculations are derived from the updated and streamlined version of the template used by the PUC called "Computation of Actual Performance Incetive-Program Year Two" of DG 02-106 and DG 05-141.
In the Commission approved Settlement Agreement that is part of Order 24,109, the Settling Parties and Staff agree to adopt the simplified Staff template of November 2002 ("Staff Template") attached to the Settlement Agreement as Exhibit G. This template shall be used only for purposes of establishing a benchmark for the Gas Utilities' incentive sharing mechanism described in Section II(H) of the Settlement Agreement. The Staff Template allows for an evaluation of the Programs on a year-by-year basis.

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual increase in rates	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/09- sales and transportation	152,010,247	therms
Surcharge per therm	$0.0000	per therm
Total Environmental Surcharge	$0.0000	

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Concord Pond

internal order no. 500061 (formerly acc no. 1796)

	(thru 3/98) pool #1	(4/98 - 9/98) pool #2	(10/98 - 9/15/99) pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	subtotal
Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	5,979,223
Remediation costs (i.o. 500005)	-	-	-	-						-
A Subtotal - remediation costs	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	5,979,223
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)			(14,314)	(13,446)	-	(2,075,704)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-						(445,985)
Recovery costs (i.o. 500004)	623,784	-	-	-				-	-	623,784
Transfer Credit from Gas Restructuring										-
B Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(1,897,905)
A-B Total net expenses to recover	520,030	1,409,330	1,654,552	95,798	60,293	21,613	81,979	142,350	95,374	4,081,318
Surcharge revenue:										
actual June 1998 - October 1998	(54,889)	-	-	-						(54,889)
actual November 1998 - October 1999	(287,010)	(251,133)	-	-						(538,143)
actual November 1999 - October 2000	(178,131)	(266,400)	(316,340)	-						(760,871)
actual November 2000 - October 2001	-	(292,420)	(334,194)	(13,925)						(640,539)
actual November 2001 - October 2002	-	(281,914)	(318,686)	(24,514)						(625,114)
actual November 2002 - October 2003	-	(258,347)	(334,331)	(15,197)						(607,874)
actual November 2003 - October 2004	-	(14,567)	(276,773)	(14,567)						(305,907)
Actual November 2004- October 2005	-	-	(56,719)	(14,180)	(14,180)					(85,078)
Actual November 2005- October 2006	-	-	-	(6,875)	(6,875)					(13,750)
Actual November 2006- October 2007	-	-	-	-	-	-	(14,091)			(14,091)
Actual November 2007- October 2008										-
AES collections					(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(81,988)
Gas Street overcollection	-	(23,511)								(23,511)
Prior Period Pool under/overcollection		-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	
C Surcharge Subtotal	(520,030)	(1,388,292)	(1,616,004)	(50,710)	(9,559)	39,108	34,729	104,437	234,190	(3,751,754)
D Net balance to be recovered (A-B+C)	-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,564	329,564
E Allocation of Litigated Recovery					-		-		(329,564)	(329,564)
Surcharge calculation 2007/2008										
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-
remaining life	-	-	-	-	36	48	60	72	84	
one year	-	-	-	-	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-		-	
Required annual increase in rates 2007/2008: smaller of D or F	-	-	-	-	-	-	-		-	-
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000124

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Laconia & Liberty Hill

		i.o. no. 500005 (through 9/15/99) pool #1	(9/99 - 9/00) pool #2	(9/00 - 9/01) pool #3	(9/04 - 9/05) pool #4	(9/05 - 9/06) pool #5	(9/06 - 9/07) pool #6	(9/07 - 9/08) pool #7	subtotal
	Remediation costs (i.o. 500061)	-	-		-				-
	Remediation costs (i.o. 500005)	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	434,450	10,104,938
A	Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	434,450	10,104,938
	Cash recoveries (i.o. 500061)	-	-	-	-	-	-	-	-
	Cash recoveries (i.o. 500004)	-	-	-	-	-	-	-	-
	Recovery costs (i.o. 500004)	-	-	-			11,643	21,729	33,372
	Transfer Credit from Gas Restructuring						-	-	-
B	Subtotal - net recoveries	-	-	-	-	-	11,643	21,729	33,372
A-B	Total net expenses to recover	1,027,747	3,513,285	700,000	9,702	2,330,555	2,100,842	456,179	10,138,310
	Surcharge revenue:								
actual	June 1998 - October 1998	-	-	-	-	-		-	-
actual	November 1998 - October 1999	-	-	-	-	-		-	-
actual	November 1999 - October 2000	(151,933)	-	-	-	-		-	(151,933)
actual	November 2000 - October 2001	(153,172)	(543,065)	-	-	-		-	(696,237)
actual	November 2001 - October 2002	(159,343)	(527,057)	(110,314)	-	-		-	(796,714)
actual	November 2002 - October 2003	(151,969)	(547,087)	(106,378)	-	-		-	(805,434)
actual	November 2003 - October 2004	(131,103)	(466,143)	(101,969)					(699,215)
Actual	November 2004- October 2005	(127,617)	(439,570)	(85,078)					(652,264)
Actual	November 2005- October 2006	(141,176)	(453,736)	(96,247)	-	-		-	(691,159)
Actual	November 2006- October 2007	-	(549,539)	(98,635)	-	(309,996)			(958,171)
Actual	November 2007- October 2008								-
	AES collections								-
	Gas Street overcollection								-
	Prior Period Pool under/overcollection		11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	
C	Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	(5,451,127)
D	Net balance to be recovered (A-B+C)	11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	4,687,183	4,687,183
E	Allocation of Litigated Recovery							(4,687,183)	(4,687,183)
	Surcharge calculation 2007/2008								
	Unrecovered costs (D+E)	-	-	-	-			-	-
	remaining life	-	-	-	48	60	72	84	
	one year	-	-	-	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	
	Required annual increase in rates 2007/2								
	smaller of D or F	-	-	-	-	-		-	-
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000125

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Manchester

		(9/00 - 9/01) pool #1	(9/02 - 9/03) pool #2	(9/02 - 9/03) pool #3 (withdrawn 2/1/04)	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8	subtotal
	Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,335,075	8,097,173
	Remediation costs (i.o. 500005)	495,106	329,986							825,092
A	Subtotal - remediation costs	495,106	329,986	-	335,338	1,989,848	875,702	561,210	4,335,075	8,922,265
	Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)	(1,893,328)
	Cash recoveries (i.o. 500004)	-	-							-
	Recovery costs (i.o. 500004)	-	-		1,242,326			2,546	-	1,244,872
	Transfer Credit from Gas Restructuring							-	-	-
B	Subtotal - net recoveries	-	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	(648,457)
A-B	Total net expenses to recover	495,106	329,986	-	1,577,664	1,989,848	330,162	343,402	3,207,639	8,273,808
	Surcharge revenue:									
actual	June 1998 - October 1998	-	-	-	-					-
actual	November 1998 - October 1999	-	-	-	-					-
actual	November 1999 - October 2000	-	-	-	-					-
actual	November 2000 - October 2001	-	-	-	-					-
actual	November 2001 - October 2002	(73,543)	-	-	-					(73,543)
actual	November 2002 - October 2003	(75,984)	-	-	-					(75,984)
actual	November 2003 - October 2004	(72,835)	(24,416)	(41,325)	-					(138,576)
Actual	November 2004- October 2005	(70,898)	(42,539)	-	(212,695)	-			-	(326,132)
Actual	November 2005- October 2006	(54,998)	(41,249)	-	(206,243)	(261,242)			-	(563,732)
Actual	November 2006- October 2007	(70,454)	(56,363)	-	(211,361)	(281,815)	(42,272)			(662,265)
Actual	November 2007- October 2008									-
	AES collections									-
	Gas Street overcollection									-
	Prior Period Pool under/overcollection		76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	
C	Surcharge Subtotal	(418,713)	(88,173)	200,488	(429,812)	604,796	2,552,371	2,882,534	3,225,936	(1,840,233)
D	Net balance to be recovered (A-B+C)	76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	6,433,575	6,433,575
E	Allocation of Litigated Recovery			-	-	-			(6,433,575)	(6,433,575)
	Surcharge calculation 2007/2008									
	Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-
	remaining life	-	-	-	36	48	60	72	84	
	one year	-	-	-	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	-	
	Required annual increase in rates 2007/2 smaller of D or F	-	-	-	-	-	-		-	-
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000126

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	Nashua								
	(9/00 - 9/01) pool #1	**(9/01 - 9/02) pool #2**	**(9/02 - 9/03) pool #3**	**(9/03 - 9/04) pool #4**	**(9/04 - 9/05) pool #5**	**(9/05 - 9/06) pool #6**	Corrected per 2/08 Audit **(9/06 - 9/07) pool #7**	**(9/07 - 9/08) pool #8**	**subtotal**
Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	357,904
Remediation costs (i.o. 500005)	1,233,726	362,663	175,178						1,771,567
A Subtotal - remediation costs	1,233,726	362,663	175,178	10,841	206,367	23,354	9,737	107,605	2,129,470
									-
Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(33,146)
Cash recoveries (i.o. 500004)	-	-	-						-
Recovery costs (i.o. 500004)	-	-	-			5,449	12,938	-	18,388
Transfer Credit from Gas Restructuring							-	-	-
B Subtotal - net recoveries	-	-	-	-		(13,131)	8,787	(10,414)	(14,758)
									-
A-B Total net expenses to recover	1,233,726	362,663	175,178	10,841	206,367	10,223	18,524	97,191	2,114,712
Surcharge revenue:									
actual June 1998 - October 1998	-	-	-	-					-
actual November 1998 - October 1999	-	-	-	-					-
actual November 1999 - October 2000	-	-	-	-					-
actual November 2000 - October 2001	-	-	-	-					-
actual November 2001 - October 2002	(183,857)	-	-	-					(183,857)
actual November 2002 - October 2003	(182,362)	(60,787)	-	-					(243,150)
actual November 2003 - October 2004	(174,804)	(43,701)	(29,134)	-					(247,639)
Actual November 2004- October 2005	(170,156)	(42,539)	(28,359)	-					(241,054)
Actual November 2005- October 2006	(164,995)	(54,998)	(27,499)	-	(27,499)			-	(274,991)
Actual November 2006- October 2007	(169,089)	(56,363)	(28,181)	-	(28,181)	-			(281,815)
Actual November 2007- October 2008									-
AES collections									-
Gas Street overcollection									-
Prior Period Pool under/overcollection		188,463	292,737	354,741	365,582	516,269	526,492	545,015	
C Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	(1,472,506)
D Net balance to be recovered (A-B+C)	188,463	292,737	354,741	365,582	516,269	526,492	545,015	642,206	642,206
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	(642,206)
Surcharge calculation 2007/2008									
Unrecovered costs (D+E)	-	-	-	-	-	-		-	-
remaining life	-	12	24	36	48	60	72	84	
one year	-	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	
Required annual increase in rates 2007/2 smaller of D or F	-	-	-	-	-	-		-	-
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000127

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	Dover						Keene					
	(9/02 - 9/03) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #4	subtotal	(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	subtotal
Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	21,142	-					-
Remediation costs (i.o. 500005)	181,066					181,066	10,165	6,606	35,111	8,766	32	60,680
A Subtotal - remediation costs	181,066	18,854	2,288	-	-	202,208	10,165	6,606	35,111	8,766	32	60,680
												-
Cash recoveries (i.o. 500061)	-					-	-					-
Cash recoveries (i.o. 500004)	-					-	-					-
Recovery costs (i.o. 500004)	-					-			18,831	823	-	19,655
Transfer Credit from Gas Restructuring						-				-	-	-
B Subtotal - net recoveries	-					-	-		18,831	823	-	19,655
A-B Total net expenses to recover	181,066	18,854	2,288	-	-	202,208	10,165	6,606	53,942	9,589	32	80,335
												-
												-
Surcharge revenue:												-
actual June 1998 - October 1998	-					-	-					-
actual November 1998 - October 1999	-					-	-					-
actual November 1999 - October 2000	-					-	-					-
actual November 2000 - October 2001	-					-	-					-
actual November 2001 - October 2002	-					-	-					-
actual November 2002 - October 2003	-					-	-					-
actual November 2003 - October 2004	(29,134)					(29,134)	-					-
Actual November 2004- October 2005	(28,359)					(28,359)	-	-			-	-
Actual November 2005- October 2006	(27,499)	-			-	(27,499)	-	-			-	-
Actual November 2006- October 2007	(28,181)	-	-			(28,181)	-	-	(14,091)			(14,091)
Actual November 2007- October 2008						-						-
AES collections						-						-
Gas Street overcollection						-						-
Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034			10,165	16,771	56,622	66,211	
C Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	(113,174)	-	10,165	2,680	56,622	66,211	(14,091)
D Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	89,034	10,165	16,771	56,622	66,211	66,244	66,244
												-
E Allocation of Litigated Recovery		-		-	(89,034)	(89,034)	-	-	-	-	(66,244)	(66,244)
												-
Surcharge calculation 2007/2008												-
Unrecovered costs (D+E)	-	-	-		-	-	-	-	-		-	-
remaining life	24	48	60	72	84		36	48	60	72	84	
one year	12	12	12	12	12		12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-		-	-	-	-	-	
Required annual increase in rates 2007/2												
smaller of D or F	-	-	-		-	-	-	-	-		-	-
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000128

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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		Concord					
		(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	Corrected per 1/24/07 Audit (9/05 - 9/06) pool #3	Corrected per 2/08 Audit (9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	subtotal
	Remediation costs (i.o. 500061)	-					-
	Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	405,116
A	Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	405,116
							-
	Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	(82,817)
	Cash recoveries (i.o. 500004)	-					-
	Recovery costs (i.o. 500004)					1,432	1,432
	Transfer Credit from Gas Restructuring			-			-
B	Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	(81,385)
A-B	Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	323,731
							-
							-
	Surcharge revenue:						-
actual	June 1998 - October 1998	-					-
actual	November 1998 - October 1999	-					-
actual	November 1999 - October 2000	-					-
actual	November 2000 - October 2001	-					-
actual	November 2001 - October 2002	-					-
actual	November 2002 - October 2003	-					-
actual	November 2003 - October 2004	-					-
Actual	November 2004- October 2005						-
Actual	November 2005- October 2006	-	(27,499)			-	(27,499)
Actual	November 2006- October 2007	-	(28,181)	-			(28,181)
Actual	November 2007- October 2008						-
	AES collections						-
	Gas Street overcollection						-
	Prior Period Pool under/overcollection		22,191	187,442	209,549	271,214	
C	Surcharge Subtotal	-	(33,490)	187,442	209,549	271,214	(55,681)
D	Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	268,051
							-
E	Allocation of Litigated Recovery	-	-	-	-	(268,051)	(268,051)
							-
	Surcharge calculation 2007/2008						-
	Unrecovered costs (D+E)	-	-	-		-	-
	remaining life	48	60	72		84	
	one year	12	12	12		12	
F	amortization 2007/2008	-	-	-		-	
	Required annual increase in rates 2007/2 smaller of D or F	-	-	-		-	-
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000129

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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		General							
		(9/02 - 9/03) pool #1	**(9/03 - 9/04) pool #2**	**(9/04 - 9/05) pool #3**	Corrected per 1/24/07 Audit **(9/05 - 9/06) pool #4**	**(9/06 - 9/07) pool #5**	**(9/07 - 9/08) pool #6**	**subtotal**	**MGP Remediation subtotal**
	Remediation costs (i.o. 500061)	-						-	14,455,442
	Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	625,611	13,974,069
A	Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	625,611	28,429,511
	Cash recoveries (i.o. 500061)	-				-	-	-	(4,084,995)
	Cash recoveries (i.o. 500004)	-						-	(445,985)
	Recovery costs (i.o. 500004)				290,155	31,826	16,012	337,993	2,279,495
	Transfer Credit from Gas Restructuring	(3,331)			-			(3,331)	(3,331)
B	Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	334,662	(2,254,816)
A-B	Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	960,273	26,174,695
									26,174,695
									-
	Surcharge revenue:								
actual	June 1998 - October 1998	-	-					-	(54,889)
actual	November 1998 - October 1999	-	-					-	(538,143)
actual	November 1999 - October 2000	-	-					-	(912,804)
actual	November 2000 - October 2001	-	-					-	(1,336,776)
actual	November 2001 - October 2002	-	-					-	(1,679,228)
actual	November 2002 - October 2003	-	-					-	(1,732,442)
actual	November 2003 - October 2004	(8,265)	-					(8,265)	(1,428,735)
Actual	November 2004- October 2005		(70,898)					(70,898)	(1,403,787)
Actual	November 2005- October 2006		(68,748)	(27,499)			-	(96,247)	(1,694,877)
Actual	November 2006- October 2007		(77,499)	(28,181)	(49,318)			(154,998)	(2,141,793)
Actual	November 2007- October 2008							-	-
	AES collections		-					-	(81,988)
	Gas Street overcollection							-	(23,511)
	Prior Period Pool under/overcollection		(8,388)	313,370	465,817	741,010	794,853	-	
C	Surcharge Subtotal	(8,265)	(225,533)	257,689	416,499	741,010	794,853	(330,408)	(13,028,973)
D	Net balance to be recovered (A-B+C)	(8,388)	313,370	465,817	741,010	794,853	629,865	629,865	13,145,721
E	Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	(629,865)	(13,145,721)
	Surcharge calculation 2007/2008								
	Unrecovered costs (D+E)	-	-	-	-		-	-	
	remaining life		36	48	60	72	84		
	one year		12	12	12	12	12		
F	amortization 2007/2008		-	-	-	-	-		
	Required annual increase in rates 2007/2 smaller of D or F	-	-	-	-		-	-	-
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	**155,445,404**
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	**$0.0000**

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000130

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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Cash Recoveries[1]

									Corrected per 1/24/07 Audit		
		(9/07 - 9/08) Concord Pond	**(9/06 - 9/07) Concord Pond**	**(9/05 - 9/06) Concord Pond**	**(9/04- 9/05) Concord Pond**	**(9/03 - 9/04) Concord Pond**	**(9/07 - 9/08) Laconia**	**(9/06 - 9/07) Laconia**	**(9/05 - 9/06) Laconia**	**(9/04 - 9/05) Laconia**	**(9/03 - 9/04) Laconia**
	Remediation costs (i.o. 500061)	-		-	-	-	-			-	-
	Remediation costs (i.o. 500005)	-		-	-	-	-			-	-
A	Subtotal - remediation costs	-		-	-	-	-			-	-
	Cash recoveries (i.o. 500061)										
	Cash recoveries (i.o. 500004)	568	-	-	-	(648,000)	-	-	-	(23,619)	(2,677,000)
	Recovery costs (i.o. 500004)	-	-	73	-	658,508	-	45	22,240	486,894	1,492,967
	Transfer Credit from Gas Restructuring	-	-	-	-	-					
B	Subtotal - net recoveries	568	-	73	-	10,508	-	45	22,240	463,275	(1,184,033)
A-B	Total net expenses to recover	568	-	73	-	10,508	-	45	22,240	463,275	(1,184,033)
	Surcharge revenue:										
actual	June 1998 - October 1998	-		-	-	-					
actual	November 1998 - October 1999	-		-	-	-					
actual	November 1999 - October 2000	-		-	-	-					
actual	November 2000 - October 2001	-		-	-	-					
actual	November 2001 - October 2002	-		-	-	-					
actual	November 2002 - October 2003	-		-	-	-					
actual	November 2003 - October 2004	-		-	-	-					
Actual	November 2004- October 2005										
Actual	November 2005- October 2006										
Actual	November 2006- October 2007										
Actual	November 2007- October 2008										
	AES collections	-		-	-	-					
	Gas Street overcollection	-		-	-	-					
	Prior Period Pool under/overcollection										
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	568	-	73	-	10,508	-	45	22,240	463,275	(1,184,033)
E	Allocation of Litigated Recovery										
	Surcharge calculation 2007/2008										
	Unrecovered costs (D+E)										
	remaining life										
	one year										
F	amortization 2007/2008										
	Required annual increase in rates 2007/2										
	smaller of D or F										
	forecasted therm sales										
	surcharge per therm										

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000131

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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		(9/07 - 9/08) Manchester	(9/06 - 9/07) Manchester	Corrected per 1/24/07 Audit (9/05 - 9/06) Manchester	(9/04 - 9/05) Manchester	(9/03 - 9/04) Manchester	(9/07 - 9/08) Nashua	(9/06 - 9/07) Nashua	(9/05 - 9/06) Nashua	(9/04 - 9/05) Nashua	(9/03 - 9/04) Nashua
	Remediation costs (i.o. 500061)						-			-	
	Remediation costs (i.o. 500005)						-			-	
A	Subtotal - remediation costs						-			-	
	Cash recoveries (i.o. 500061)										
	Cash recoveries (i.o. 500004)	-	(630,000)	(1,725,792)	(754,938)	-	(1,032,186)	(544,402)	(625,000)	(782,450)	(795,000)
	Recovery costs (i.o. 500004)	77,222	195,929	941,433	307,062	951,425	561,030	78,298	645,302	537,552	655,683
	Transfer Credit from Gas Restructuring										
B	Subtotal - net recoveries	77,222	(434,071)	(784,359)	(447,876)	951,425	(471,155)	(466,104)	20,302	(244,898)	(139,317)
A-B	Total net expenses to recover	77,222	(434,071)	(784,359)	(447,876)	951,425	(471,155)	(466,104)	20,302	(244,898)	(139,317)
	Surcharge revenue:										
actual	June 1998 - October 1998	-		-	-						
actual	November 1998 - October 1999	-	-	-	-						
actual	November 1999 - October 2000	-	-	-	-						
actual	November 2000 - October 2001	-	-	-	-						
actual	November 2001 - October 2002	-	-	-	-						
actual	November 2002 - October 2003	-	-	-	-						
actual	November 2003 - October 2004	-	-	-	-						
Actual	November 2004- October 2005										
Actual	November 2005- October 2006			-	-						
Actual	November 2006- October 2007										
Actual	November 2007- October 2008										
	AES collections	-	-								
	Gas Street overcollection	-	-								
	Prior Period Pool under/overcollection			-	-						
				-	-						
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	77,222	(434,071)	(784,359)	(447,876)	951,425	(471,155)	(466,104)	20,302	(244,898)	(139,317)
E	Allocation of Litigated Recovery										
	Surcharge calculation 2007/2008										
	Unrecovered costs (D+E)										
	remaining life										
	one year										
F	amortization 2007/2008										
	Required annual increase in rates 2007/2										
	smaller of D or F										
	forecasted therm sales										
	surcharge per therm										

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000132

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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		(9/07 - 9/08) Dover	(9/06 - 9/07) Dover	(9/05 - 9/06) Dover	(9/04 - 9/05) Dover	(9/03 - 9/04) Dover	(9/07 - 9/08) Keene	(9/06 - 9/07) Keene	(9/05 - 9/06) Keene	(9/04 - 9/05) Keene	(9/03 - 9/04) Keene	(9/06 - 9/07) General	subtotal	MGP TOTAL
	Remediation costs (i.o. 500061)	-		-	-				-	-			-	14,455,442
	Remediation costs (i.o. 500005)	-		-	-				-	-			-	13,974,069
A	Subtotal - remediation costs	-		-	-				-	-			-	28,429,511
	Cash recoveries (i.o. 500061)												-	(4,084,995)
	Cash recoveries (i.o. 500004)	(2,133)	-	(237,489)	(7,150)	(645,500)			(700,000)	(211,213)	0	(10,760,900)	(22,802,203)	(23,248,188)
	Recovery costs (i.o. 500004)	-	14,848	117,621	517,891	500,868	1,559	28,211	309,618	56,392	121,018		9,279,688	11,559,183
	Transfer Credit from Gas Restructuring												-	(3,331)
B	Subtotal - net recoveries	(2,133)	14,848	(119,868)	510,741	(144,632)	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(2,761,615)	(5,016,432)
													-	-
A-B	Total net expenses to recover	(2,133)	14,848	(119,868)	510,741	(144,632)	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(13,522,515)	12,652,180
	Surcharge revenue:													
actual	June 1998 - October 1998												-	(54,889)
actual	November 1998 - October 1999												-	(538,143)
actual	November 1999 - October 2000												-	(912,804)
actual	November 2000 - October 2001												-	(1,336,776)
actual	November 2001 - October 2002												-	(1,679,228)
actual	November 2002 - October 2003												-	(1,732,442)
actual	November 2003 - October 2004												-	(1,428,735)
Actual	November 2004- October 2005												-	(1,403,787)
Actual	November 2005- October 2006													(1,694,877)
Actual	November 2006- October 2007													(2,141,793)
Actual	November 2007- October 2008													-
	AES collections												-	(81,988)
	Gas Street overcollection												-	(23,511)
	Prior Period Pool under/overcollection												-	
													-	
C	Surcharge Subtotal	-	-	-	-	-		-	-	-	-		-	(13,028,973)
													-	
													-	
D	Net balance to be recovered (A-B+C)	(2,133)	14,848	(119,868)	510,741	(144,632)	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(13,522,515)	(376,794)
E	Allocation of Litigated Recovery												13,145,721	
													(376,794)	
	Surcharge calculation 2007/2008													
	Unrecovered costs (D+E)													
	remaining life													
	one year													
F	amortization 2007/2008													
	Required annual increase in rates 2007/2													
	smaller of D or F													
	forecasted therm sales													
	surcharge per therm													

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000133

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Expense and Collection Summary per Year

		(thru 3/98)	(4/98 - 9/98)	10/98 - 9/15/99	(9/99 - 9/00)	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	Total
	Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,538,054	14,455,442
	Remediation costs (i.o. 500005)	-	-	1,027,747	3,513,285	2,428,832	362,663	689,437	571,259	445,367	2,444,366	2,229,625	261,488	13,974,069
A	Subtotal - remediation costs	1,422,811	1,843,806	3,181,982	3,642,287	2,428,832	362,663	689,437	977,731	2,682,050	3,442,003	2,956,367	4,799,542	28,429,511
	Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(4,084,995)
	Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	(23,248,188)
	Recovery costs (i.o. 500004)	623,784	-	-	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	11,559,183
	Transfer Credit from Gas Restructuring	-	-	-	-	-	-	(3,331)	-	-	-	-	-	(3,331)
B	Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(3,331)	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(15,777,331)
A-B	Total net expenses to recover	520,030	1,409,330	2,682,299	3,609,083	2,428,832	362,663	686,106	1,835,026	2,808,471	1,903,772	(8,887,756)	3,294,324	12,652,180
	Surcharge revenue:													
actual	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	(54,889)
actual	November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	-	(538,143)
actual	November 1999 - October 2000	(178,131)	(266,400)	(468,273)	-	-	-	-	-	-	-	-	-	(912,804)
actual	November 2000 - October 2001	-	(292,420)	(487,366)	(556,990)	-	-	-	-	-	-	-	-	(1,336,776)
actual	November 2001 - October 2002	-	(281,914)	(478,029)	(551,571)	(367,714)	-	-	-	-	-	-	-	(1,679,228)
actual	November 2002 - October 2003	-	(258,347)	(486,300)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	(1,732,442)
actual	November 2003 - October 2004	-	(14,567)	(407,875)	(480,710)	(349,608)	(43,701)	(132,274)	-	-	-	-	-	(1,428,735)
Actual	November 2004- October 2005	-	-	(184,336)	(453,749)	(326,132)	(42,539)	(99,258)	(297,773)	-	-	-	-	(1,403,787)
Actual	November 2005- October 2006	-	-	(141,176)	(460,610)	(316,240)	(54,998)	(96,247)	(281,866)	(343,739)	-	-	-	(1,694,877)
Actual	November 2006- October 2007	-	-	-	(549,539)	(338,178)	(56,363)	(112,726)	(288,860)	(366,359)	(429,768)	-	-	(2,141,793)
Actual	November 2007- October 2008													
	AES collections	-	-	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(81,988)
	Gas Street overcollection	-	(23,511)	-	-	-	-	-	-	-	-	-	-	(23,511)
	Prior Period Pool under/overcollection													
C	Surcharge Subtotal	(520,030)	(1,388,292)	(2,653,355)	(3,615,454)	(2,062,596)	(258,389)	(440,504)	(902,092)	(721,725)	(441,669)	(12,271)	(12,597)	(13,028,973)
D	Net balance to be recovered (A-B+C)	-	21,038	28,944	(6,371)	366,236	104,274	245,602	932,934	2,086,746	1,462,103	(8,900,027)	3,281,727	(376,794)

E Allocation of Litigated Recovery

Surcharge calculation 2007/2008
Unrecovered costs (D+E)
remaining life
one year
F amortization 2007/2008

Required annual increase in rates 2007/2
smaller of D or F

forecasted therm sales

surcharge per therm

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000134

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

CONCORD FORMER MGP

NO.

1. SITE LOCATION: One Gas Street, Concord, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: EnergyNorth Natural Gas, Inc. (ENGI) received a Notice Letter from the New Hampshire Department of Environmental Services (NHDES) in September, 1992. The Notice related primarily to contamination identified in the pond adjacent to Exit 13 off Interstate 93, although it was broad enough to also include the former manufactured gas plant (MGP) site itself.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond, as the NHDOT began site preparation work for the reconfiguration of that interchange. Subsequent investigations by ENGI and others indicate that contaminants originating from the MGP on Gas Street are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI has continued to monitor groundwater semiannually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003 and 2007, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit. These sample results will be evaluated over time to address the efficacy of the existing remedy, and determine if additional treatment may be necessary.

   The New Hampshire Department of Transportation (NHDOT) contacted ENGI in August 2001 and February 2002 regarding possible coal tar-related impacts in a sewer line on a parcel adjacent to the former gas plant. NHDOT is currently conducting groundwater monitoring as part of a Groundwater Management Zone Permit on this parcel. ENGI met with NHDOT and NHDES in January 2003 to review the results of its 2002 site investigation. Limited coal tar impacts were observed in groundwater and subsurface soils at select locations.

   On July 15, 2003, NHDES issued a letter to KeySpan requesting submission of a schedule and scope of work for a site investigation of the gas plant by mid-September 2003. ENGI proposed a May 2005 date for submission of a site investigation report for the former manufactured gas plant on Gas Street to NHDES by way of a letter dated

October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 and is planning for the upcoming site investigation activities, which are expected commence in fall 2008, pending access being provided by several property owners.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results are being used to prepare the Remedial Action Plan which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design.

ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. Completion of the remedial design is ongoing. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way. ENGI is currently drafting an agreement to clarify the responsibilities of the three parties.

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond. In May 2007, NHDES approved ENGI's April 2007 scope of work to conduct additional investigations around this well to determine the extent of the coal tar impacts and the feasibility of removing it from the subsurface. These activities are on-going.

LINE
NO.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI is undertaking a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007 and completion of the design will be completed pending an agreement between the City, NHDOT and ENGI.

   In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the gas plant. ENGI submitted the scope to NHDES in May 2004, and implemented it between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities will be performed in 2008.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Concord MGP operated from approximately 1850 to 1952, when the natural gas pipeline was extended to Concord. The plant was constructed and operated by predecessors of the Concord Gas Company, which later became known as the Concord Natural Gas Company. By virtue of a merger, ENGI acquired Concord Natural Gas. As has been reported previously by ENGI, it filed a contribution claim in the United States District Court for the District of New Hampshire against the successor to the United Gas Improvement Company. In that claim, ENGI alleged that under the federal Superfund statute, the United Gas Improvement Company exercised control over the operations of the Concord Gas Plant to the extent that the United Gas Improvement Company should be considered an "operator" under the statute. That matter was settled in 1997.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Numerous confidential settlements with insurance carriers and with one private party have been entered into. *Insurance recovery efforts at the Concord Site are complete.*

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
KEYSPAN PROJECT DEF056

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Anchor Environmental	11636	13,586.75				13,586.75
2	Anchor Environmental	11851	326.00				326.00
3	Anchor Environmental	12199	2,088.25				2,088.25
4	Anchor Environmental	12666	7,120.31				7,120.31
5	Anchor Environmental	12878	1,346.82				1,346.82
6	Anchor Environmental	12503	434.25				434.25
7	Anchor Environmental	13217	456.50				456.50
8	Anchor Environmental	13404	1,098.67				1,098.67
9	Clean Harbors	SB0739103	739.28				739.28
10	Clean Harbors	SB0700998	1,135.26				1,135.26
11	Clean Harbors	SB0862533	1,149.21				1,149.21
12	Environmental Payroll	Timesheet	1,527.60				1,527.60
13	Environmental Payroll	Timesheet	938.36				938.36
14	Fed Ex	2-316-47894	7.39				7.39
15	GEI Consultants	45770	4,673.70				4,673.70
16	GEI Consultants	45911	12,060.70				12,060.70
17	GEI Consultants	46088	4,387.51				4,387.51
18	GEI Consultants	46392	5,533.36				5,533.36
19	GEI Consultants	46223	19,026.17				19,026.17
20	GEI Consultants	46577	4,153.54				4,153.54
21	GEI Consultants	47247	723.47				723.47
22	GEI Consultants	45943	2,118.74				2,118.74
23	GEI Consultants	46619	2,881.79				2,881.79
24	GEI Consultants	47137	3,317.41				3,317.41
25	GEI Consultants	47429	972.43				972.43
26	New Hampshire Department of Environmental Servic	199212014-03	2,730.47				2,730.47
27	New Hampshire Department of Environmental Servic	199212014-05	839.69				839.69
28							
29	**Total Pool Activity**		**95,373.63**	**-**	**-**	**-**	**95,373.63**

00000138

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
KEYSPAN PROJECT DEF077

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Environmental Staff Payroll	Timesheet	889.20			889.20
2	Environmental Staff Payroll	Timesheet	364.04			364.04
3	Fed Ex	2-303-43386	12.04			12.04
4	UGI	20468359	-		(6,437.57)	(6,437.57)
5	UGI	20478547	-		(6,163.78)	(6,163.78)
6	McLane	2008040245	-	133.00		133.00
7	McLane	2008030390	-	1,299.00		1,299.00
8	New Hampshire Department of Environm	198904063-01	6,130.82			6,130.82
9	New Hampshire Department of Environm	199804063-02	609.93			609.93
10			-			-
11	**Total Pool Activity**		**8,006.03**	**1,432.00**	**(12,601.35)**	**(3,163.32)**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD - LITIGATION
KEYSPAN PROJECT DEF051

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Mclane	2008020917	568.00	-		568.00
2			-			-
3	**Total Pool Activity**		**568.00**		**-**	**568.00**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.

2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI), another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations are necessary to determine the extent of the contamination.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Winnipesaukee River. The full nature and extent of contamination is unknown at this time. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials from the former MGP were disposed of at the Liberty Hill disposal area, and MGP-related constituents have been detected in soil and ground water.

LINE
NO.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: Based on the settlement with PSNH that has previously been reported to the Commission, ENGI has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area. Please contact PSNH and refer to PSNH filings with NHDES for complete information on material developments and interactions with environmental authorities.

With respect to the Liberty Hill disposal area, in October 2004, ENGI notified NHDES of the possible existence of this disposal site; the site was assigned disposal site number 200411113 by NHDES. NHDES collected drinking water samples from two residential wells in the vicinity in December 2004 and from three additional residential wells in June and July 2005; no MGP-related contaminants were detected. In January 2005, NHDES requested that ENGI conduct a preliminary site investigation on the two residential properties. ENGI submitted a scope of work for the investigation to NHDES on March 2, 2005. The investigation began in July 2005 and was completed in June 2006 with the submission of the Site Investigation Report.

Additional site investigations were conducted in 2006 and summarized in the December 20, 2006 Interim Data Report #2 submitted to NHDES. Based upon the results of the investigations, remediation is required at the site. In response, a Remedial Action Plan (RAP) was submitted to NHDES on February 28, 2007. The RAP presented NHDES with several remedial alternatives to address soil and groundwater contamination at the site. The February 2007 RAP identified soil excavation (to a depth of 3 feet), construction of a containment wall and impermeable cap on the four residential properties purchased by ENGI as the recommended alternative. In September 2007, NHDES responded to the February 2007 RAP and required that ENGI evaluate additional remedial alternatives that included further soil removal. In November 2007, a revised RAP was submitted to NHDES. The revised RAP recommended a remedial alternative that included removal of tar-saturated soils to a depth of approximately 45 feet, construction of a containment wall and impermeable cap on the four residential properties owned by ENGI. On February 29, 2008, NHDES issued a letter to ENGI indicating that NHDES had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company will submit a Scope of Work for groundwater modeling and additional data collection to NHDES in September 2008 and expects to complete the modeling and data collection activities in the first quarter of 2009, assuming that NHDES approves of the scope in October 2008.

In addition to the RAP activities, ENGI has also performed numerous other activities requested by NHDES in 2008, including sampling of a groundwater seep on a private property near the site, evaluation of options for providing financial assurances to NHDES for the site remediation activities, coal tar recovery, and semi-annual groundwater and surface water sampling activities.

In conjunction with the Site Investigation work, ENGI has acquired 4 properties on Liberty Hill Road to facilitate remediation activities, and eliminate any potential risk to residents associated with a significant remediation and construction project. The properties were obtained based upon arms-length negotiations, and in one instance to settle potential litigation.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Please refer to Item 4.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc. (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Laconia MGP, which began operating in 1894, was included in that transaction. Gas manufacturing took place at the property until 1952, when the MGP was converted to propane. Half of the property is now owned by Robert Irwin and maintained as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

   The Liberty Hill Road parcel on which disposal was believed to have occurred was utilized as a gravel pit at the time of the disposal. It was subdivided in May 1970, and currently constitutes part of a residential subdivision.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and

LINE
NO.

all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003 the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May, 2004 the Supreme Court responded that a “continuous injury-in-fact” trigger should be applied., The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.
With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECTS DEF086 and DEF087

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Clean Harbors	SB0735506	1,041.18			1,041.18
2	Clean Harbors	SB0701415	646.00			646.00
3	Environmental Staff Payroll	Timesheet	9,165.72			9,165.72
4	Environmental Staff Payroll	Timesheet	32.36			32.36
5	Environmental Staff Travel Expenses	EXP 0231890	4.00			4.00
6	Fed Ex	2-290-45046	8.45			8.45
7	Fed Ex	2-290-45046	8.45			8.45
8	Fed Ex	2-251-18678	12.31			12.31
9	GEI Consultants	47518	12,342.35			12,342.35
10	GEI Consultants	47788	4,338.75			4,338.75
11	GEI Consultants	46222	50,747.37			50,747.37
12	GEI Consultants	46391	67,454.69			67,454.69
13	GEI Consultants	45910	512.41			512.41
14	GEI Consultants	46087	4,278.56			4,278.56
15	GEI Consultants	46857	4,483.25			4,483.25
16	GEI Consultants	46576	23,002.14			23,002.14
17	GEI Consultants	47135	32,904.75			32,904.75
18	GEI Consultants	45942	8,574.27			8,574.27
19	GEI Consultants	47249	26,881.18			26,881.18
20	GEI Consultants	46618	23,140.57			23,140.57
21	GEI Consultants	47428	5,951.21			5,951.21
22	McLane	2007070737	378.00			378.00
23	McLane	2007060083	724.50			724.50
24	McLane	2007080886	662.00			662.00
25	McLane	2007090519	4,724.29			4,724.29
26	McLane	2007100038	3,915.22			3,915.22
27	McLane	2007110406	3,319.02			3,319.02
28	McLane	2008020916	333.50			333.50
29	McLane	2007120215	12,210.50			12,210.50
30	McLane	2008030389	2,341.00			2,341.00
31	McLane	2008040244	24,551.04			24,551.04
32	McLane	2008050262	37,925.90			37,925.90
33	New Hampshire Department of Environmental Services	200411113-02	43,197.81			43,197.81
34	Ostrow & Partners	110703	1,920.00			1,920.00
35	Ostrow & Partners	120701	7,035.50			7,035.50
36	Ostrow & Partners	40801	4,540.30			4,540.30
37	Ostrow & Partners	50810	6,145.30			6,145.30
38	Ostrow & Partners	60814	300.00			300.00
39	Ostrow & Partners	70805	600.00			600.00
40	Ostrow & Partners	30203	695.00			695.00
41	Ostrow & Partners	10808	920.00			920.00
42	Ostrow & Partners	20801	1,824.50			1,824.50
43	Public Service of New Hampshire	111168	(12.80)			(12.80)
44	Public Service of New Hampshire	110514	(68.63)			(68.63)
45	Public Service of New Hampshire	41-29-09918-1-3	8.84			8.84
46	Public Service of New Hampshire	41-29-09918-1-3	8.84			8.84
47	Public Service of New Hampshire	41-29-09944-4-5	8.84			8.84
48	Public Service of New Hampshire	41-29-09918-1-3	8.84			8.84
49	Public Service of New Hampshire	41-29-09918-1-3	8.84			8.84
50	Public Service of New Hampshire	41-29-09944-4-5	9.12			9.12
51	Public Service of New Hampshire	41-29-09944-4-5	20.66			20.66
52	Public Service of New Hampshire	7535933	8.84			8.84
53	Public Service of New Hampshire	41-29-09944-4-5	44.29			44.29
54	Public Service of New Hampshire	41-29-09918-1-3	17.87			17.87
55	Public Service of New Hampshire	41-29-09944-4-5	103.39			103.39
56	Public Service of New Hampshire	41-29-09918-1-3	18.06			18.06
57	Public Service of New Hampshire	41-29-09944-4-5	68.63			68.63
58	Public Service of New Hampshire	41-29-09944-4-5	224.61			224.61
59	Public Service of New Hampshire	41-29-09918-2-1	18.47			18.47
60	Public Service of New Hampshire	41-29-09918-2-1	27.59			27.59
61	Public Service of New Hampshire	41-29-09944-5-2	51.20			51.20
62	Public Service of New Hampshire	41-29-09944-5-2	81.19			81.19
63	New Hampshire Department of Environmental Services	200411113-03	-	21,729.43		21,729.43
64			-			-
65	**Total Pool Activity**		**434,450.04**	**21,729.43**	**-**	**456,179.47**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LACONIA - LITIGATION
KEYSPAN PROJECT DEF050

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1			-	-		-
2			-			-
3						
4						
5	**NO ACTIVITY FOR THIS PERIOD**					
6						
7						
8						
9	**Total Pool Activity**		**-**	**-**	**-**	**-**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

LINE
NO.

1. SITE LOCATION: 130 Elm Street, Manchester, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: The New Hampshire Department of Environmental Services (NHDES) compiled a list of all former Manufactured Gas Plants (MGPs) in New Hampshire that were not already subject to a site investigation or remediation. In March of 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites. EnergyNorth Natural Gas, Inc. (ENGI) received a “Notification of Site Listing and Request for Site Investigation” for the former Manchester MGP from NHDES, which designated the site DES #200003011. It is understood that NHDES intended to solicit site investigation reports on all MGPs and then prioritize them for remedial action.

3. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

    - On behalf of ENGI, Harding ESE, Inc. (Harding ESE), submitted a Scoping Phase Field Investigation Scope of Work to NHDES in March 2000.

    - NHDES approved the Scoping Phase Field Investigation Scope of Work in June 2000.

    - During the summer and fall of 2000, ENGI and Harding ESE conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Manchester MGP and the nearby Merrimack River.

    - On August 31, 2000 an underground tank containing MGP residuals was discovered at the site. As required by NHDES regulations, the tank contents were removed and disposed of subject to a permit from NHDES. Harding ESE submitted a summary report to NHDES in January 2001 on behalf of ENGI documenting the response action.

    - ENGI and Harding ESE submitted the Scoping Phase Field Investigation Report to NHDES in February 2001.

    - NHDES provided comments to ENGI and Harding ESE in April 2001 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

    - ENGI responded to NHDES’ comments on the Scoping Phase Investigation Report and indicated that ENGI planned to solicit bids for the Phase II Scope of Work.

LINE
NO.

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments.

- In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage.

- In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence.

- NHDES approved the ravine sign language in April 2002.

- On May 1, 2002, ENGI issued a Request for Proposals to eight environmental consultants for the Phase II Site Investigation and Risk Characterization.

- ENGI received six proposals for the Phase II work in June 2002.

- In June 2002, the City of Manchester approved the ravine fence location and granted access to City property to install. The work was completed in August 2002.

- URS Consultants were awarded the contract to undertake the next phase of work. A Phase II Site Investigation Scope of Work was submitted in September 2002.

- Phase II field investigations began in the fall of 2002.

- In June 2003, the City of Manchester approved a proposal to construct a minor league ballpark, retail shops, parking garage, hotel and high-rise condominium complex on the Singer Park site, in the same general areas that MGP impacts were detected in ongoing Phase II investigations. Following supplemental ravine investigations during the spring and summer of 2003, the Drainage Ravine Engineering Evaluation was submitted to NHDES in January 2004, and presented four potential remedial alternatives for the ravine, which is located on a portion of Singer Park.

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers since April 2003, until they ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment are being addressed concurrently and that ENGI avoids incurring costs associated with another entity's contamination.

- ENGI entered into confidential agreements with Manchester Parkside Place (the owner of the ravine property) for access and cleanup of MGP byproducts in the ravine in January 2005.

- In January 2005, ENGI submitted a Remedial Design Report to NHDES selecting excavation and off-site disposal of source material and impacted soils as the remedial alternative for the ravine. NHDES approved of this alternative via a letter dated February 7, 2005. Eleven contractors were invited to bid on the ravine remediation in January 2005. The contract was awarded to the low bidder (ENTACT) in February 2005. Remediation of the ravine began in March and was completed in July 2005. A remedial completion report was submitted to NHDES on September 2, 2005.

- ENGI submitted a Phase II Site Investigation Report to NHDES in March 2004. The report concluded that MGP impacts (including impacted soil and groundwater and separate phase coal tar) were present in the subsurface beneath the 130 Elm Street property, in portions of Singer Park at depth and in the Merrimack River sediment. Further investigations were recommended by ENGI to completely bound the nature and extent of this contamination and a work plan proposing those investigations was submitted to NHDES in May 2004 and approved in July 2004. These supplemental investigations were completed and documented in the Supplemental Phase II Investigation Report and the Stage I Ecological Screening Report for the Merrimack River, submitted to NHDES in February and March 2005, respectively. The reports concluded that a Remedial Action Plan for the upland and Merrimack River is required. On September 15, 2005, NHDES issued a letter accepting the reports and requested ENGI prepare a Remedial Action Plan (RAP) to address impacted sediments in the Merrimack River, as well as MGP-related impacts on the upland portion of the site. Preparation of the RAP began in August 2006.

- Additional Merrimack River investigations were completed in 2007 and the Remedial Design Report for dredging approximately 9,000 cubic yards of coal tar-impacted sediments from the river was submitted to NHDES on May 11, 2007. ENGI applied for, and was granted, a Dredge and Fill Permit for the remedial dredging from NHDES and the United States Army Corps of Engineers on May 18, 2007. Dredging of the river commenced in June 2007 and was substantially completed by the end of the year. Final site restoration activities associated with the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

LINE
NO.

- Predesign investigations and preparation of a Remedial Action Plan are ongoing on the upland portion of the former MGP site in 2007. In additional, ENGI is currently commencing interim remediation activities at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale coal tar recovery and limited surface soil removal activities. Following a review of the data to be collected during some of the pilot interim activities, the upland Remedial Action Plan is expected to be completed and submitted to NHDES in fall 2009.

4. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A Remedial Action Plan is currently being developed for the upland portion of the MGP site.

5. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The former Manchester MGP is believed to have started producing coal gas in 1852. Gas was produced at the site by the Manchester Gas Company and its predecessors until the MGP was shut down in 1952 when natural gas was supplied to the city via pipeline. ENGI is the successor by merger to the Manchester Gas Company. ENGI continues to own and operate the 130 Elm Street property as an operations center.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity “operated” the Manchester Gas Plant, as defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as “CERCLA” or “Superfund”). This claim was similar to a claim litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

   Insurance recovery efforts are substantially complete, and confidential settlements have been entered into with all but one insurance company defendant. An agreement with the last remaining insurance carrier has been negotiated under which that carrier will pay ENGI's attorneys fees incurred in the litigation. It is expected that agreement will be signed by the

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beginning of August, 2008. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys fees. EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
KEYSPAN PROJECT DEF057

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Anchor Environmental	11640	18,541.63			18,541.63
2	Anchor Environmental	11892	59,436.26			59,436.26
3	Anchor Environmental	11974	37,130.68			37,130.68
4	Anchor Environmental	12210	53,622.77			53,622.77
5	Anchor Environmental	12667	50,176.45			50,176.45
6	Anchor Environmental	12875	52,068.80			52,068.80
7	Anchor Environmental	12665	84,770.85			84,770.85
8	Anchor Environmental	13405	13,211.91			13,211.91
9	Anchor Environmental	13218	45,138.78			45,138.78
10	Anchor Environmental	13944	5,375.31			5,375.31
11						
12						
13	City of Machester	671882	791.18			791.18
14	Clean Harbors	NH1374850	667.23			667.23
15	Clean Harbors	NH0720449	4,566.38			4,566.38
16	Clean Harbors	NH0745250	250.86			250.86
17	Clean Harbors	NH0715502	371.85			371.85
18	EECS Inc.	198	275.00			275.00
19	EECS Inc.	193	1,080.40			1,080.40
20	EECS Inc.	186	1,662.63			1,662.63
21	Environmental Staff Payroll	Timesheet	8,481.75			8,481.75
22	Environmental Staff Payroll	Timesheet	3,187.11			3,187.11
23	ESMI	1004105	44,932.00			44,932.00
24	ESMI	1004112	25,981.72			25,981.72
25	ESMI	1004248	20,963.58			20,963.58
26	ESMI	1004221	23,793.04			23,793.04
27	ESMI	1004169	48,705.26			48,705.26
28	ESMI	1004203	49,802.82			49,802.82
29	ESMI	1004154	59,514.80			59,514.80
30	ESMI	1004121	60,635.82			60,635.82
31	ESMI	1004119REV	2,363.04			2,363.04
32	ESMI	1004387	52,713.24			52,713.24
33	ESMI	1004516	4,615.18			4,615.18
34	ESMI	1004553	7,168.18			7,168.18
35	ESMI	1004333	15,130.32			15,130.32
36	ESMI	1004310	29,026.00			29,026.00
37	ESMI	1004352	31,705.04			31,705.04
38	Fed Ex	2-393-45723	6.97			6.97
39	Fed Ex	2-214-34675	6.82			6.82
40	Fed Ex	2-277-34351	6.77			6.77
41	Fed Ex	2-329-60023	6.74			6.74
42						
43						
44						
45						
46						
47						
48	Maxymillian Technologies	415217	2,250.00			2,250.00
49	Maxymillian Technologies	415217	73,855.21			73,855.21
50	Maxymillian Technologies	415217	247,240.60			247,240.60
51	Maxymillian Technologies	415217	773,044.24			773,044.24
52	Maxymillian Technologies	415217	526,003.73			526,003.73
53	Maxymillian Technologies	415217	101,381.31			101,381.31
54	Maxymillian Technologies	415217	342,966.56			342,966.56
55	Maxymillian Technologies	415217	761,625.28			761,625.28
56	McLane	2007100036	1,351.50			1,351.50
57	McLane	2007110404	390.00			390.00
58	McLane	2006060871	170.00			170.00
59	Mhrai, Inc.	668444	4,808.20			4,808.20
60	Mhrai, Inc.	7515982	16,000.00			16,000.00
61	Mhrai, Inc.	7529439	8,000.00			8,000.00
62	National Security Protective Services	25591	2,278.54			2,278.54
63	National Security Protective Services	25651	2,688.76			2,688.76
64	National Security Protective Services	25534	1,626.39			1,626.39
65	National Security Protective Services	25705	2,424.36			2,424.36
66	National Security Protective Services	25760	3,755.31			3,755.31
67	National Security Protective Services	25816	3,601.43			3,601.43
68	National Security Protective Services	25872	4,105.76			4,105.76
69	National Security Protective Services	25988B	804.06			804.06
70	National Security Protective Services	26051	3,450.00			3,450.00
71	National Security Protective Services	25932	4,100.59			4,100.59
72	National Security Protective Services	25988A	4,105.76			4,105.76
73	National Security Protective Services	26047	4,156.31			4,156.31

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
KEYSPAN PROJECT DEF057

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
74	National Security Protective Services	26107	4,212.49			4,212.49
75	National Security Protective Services	26228	4,331.68			4,331.68
76	National Security Protective Services	26284	4,507.12			4,507.12
77	National Security Protective Services	26169	4,828.48			4,828.48
78	National Security Protective Services	26544	1,199.02			1,199.02
79	National Security Protective Services	26598	1,207.22			1,207.22
80	National Security Protective Services	26668	1,399.66			1,399.66
81	National Security Protective Services	26490	1,439.68			1,439.68
82	National Security Protective Services	26437	1,439.68			1,439.68
83	National Security Protective Services	26396	3,164.58			3,164.58
84	National Security Protective Services	26338	4,358.89			4,358.89
85	NH Department of Environmental Services	NHD500012257	359.90			359.90
86	NH Department of Environmental Services	136671-26000	184.50			184.50
87	NH Department of Environmental Services	200003011-01	29,614.05			29,614.05
88	NH Department of Environmental Services	200003011-02	55.97			55.97
89	Ostrow & Partners	90702	762.00			762.00
90	UGI	20468359	-		(89,762.96)	(89,762.96)
91	URS	2947511	7,775.50			7,775.50
92	URS	2915837	31,748.09			31,748.09
93	URS	3001816	11,912.21			11,912.21
94	URS	2992321	20,636.27			20,636.27
95	URS	3053911	11,240.43			11,240.43
96	URS	3096387	14,953.63			14,953.63
97	URS	3131443	31,067.80			31,067.80
98	URS	3033213	43,194.33			43,194.33
99	URS	3087022	54,092.92			54,092.92
100	URS	3224818	17,361.97			17,361.97
101	URS	3266523	2,483.75			2,483.75
102	URS	3362016	348.64			348.64
103	URS	3174539	20,403.91			20,403.91
104	URS	3183072	24,792.36			24,792.36
105	URS	3270124	12,699.98			12,699.98
106	URS	3369668	287.22			287.22
107	URS	3319412	5,647.86			5,647.86
108	URS	3416042	1,618.75			1,618.75
109	URS	2956980	145,675.56			145,675.56
110						
111	**Total Pool Activity**		**4,335,075.17**	**-**	**(1,127,436.06)**	**3,207,639.11**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - LITIGATION
KEYSPAN PROJECT DEF058

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1,108 INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Fed Ex	2-329-60023	7.25			7.25
2	McLane	2007060453	-	13,609.52		13,609.52
3	McLane	2007111462	-	13,964.86		13,964.86
4	McLane	2007120594	-	27,205.10		27,205.10
5	McLane	2008010511	-	6,476.87		6,476.87
6	McLane	2008031188	-	4,747.22		4,747.22
7	McLane	2008020320	-	6,167.20		6,167.20
8	McLane	2008050263	-	1,168.00		1,168.00
9	McLane	2008040499	-	3,876.00		3,876.00
10			-			
11	**Total Pool Activity**		**7.25**	**77,214.77**	**-**	**77,222.02**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

1. SITE LOCATION: 38 Bridge Street, Nashua, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: At the end of 1998, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua manufactured gas plant (MGP) to the former plant owners/operators: EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England (ENGI), and Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities Services Company (NU). NHDES designated the site DES #199810022.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - Prior to the time NHDES issued its notice letter to ENGI, the US Environmental Protection Agency (EPA) was remediating contamination (asbestos) at a former Johns Manville plant located adjacent to, and downstream from the 38 Bridge Street property. In the course of that work, EPA detected what it determined to be MGP related residuals in Nashua River sediments containing asbestos. EPA sought reimbursement from ENGI and PSNH of only those incremental additional costs it incurred to dispose of sediments containing MGP related wastes in addition to asbestos. ENGI and PSNH entered into a settlement agreement with the EPA at the end of September 2000. Under the terms of the agreement, each company received a release from liability associated with the so-called Nashua River Superfund Site and contribution protection against future claims associated with that site. The settlement agreement made it clear that EPA does not contend that ENGI or PSNH contributed any asbestos to the Nashua River.

   - In response to the 1998 notice from NHDES, QST Environmental, Inc. (QST, subsequently Environmental Science and Engineering, Inc. (ESE), and now Harding ESE, Inc. (Harding ESE)), submitted a Scoping Phase Field Investigation Scope of Work to NHDES on behalf of ENGI in February 1999.

   - In response to comments from NHDES, QST and ENGI refined the Scope of Work for the Scoping Phase Field Investigation and resubmitted to NHDES in April 1999.

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- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.

- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.

- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.

- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.

- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.

- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.

- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.

- ENGI and ESE developed a letter discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and from PSNH/NU and submitted the document in August 2000 along with a proposed schedule for implementation.

- NHDES approved the Revised Phase II Work Plan for the 38 Bridge Street Site at the end of August 2000.

- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.

- Harding ESE submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH/NU reached agreement in late 2000 regarding sharing of costs for the remediation work and transfer of management of the remediation work to ENGI.

- Harding ESE implemented the Phase II Work Plan during the fall and winter of 2000-2001. Work entailed a comprehensive field program that included river borings and sediment samples as well as borings and monitoring wells completed on and off the property.

- NHDES provided comments on the Phase II Work Plan addendum in February 2001.

- Harding ESE responded to NHDES comments on the Phase II Work Plan addendum in March 2001.

- In May 2001, ENGI and Harding ESE submitted to NHDES a Draft Site Conceptual Model to assist with finalization of the Phase II Work Plan Addendum and met with NHDES to discuss.

- ENGI and NHDES met in early June 2001 to discuss draft site conceptual model and the overall site objectives and approach.

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June.

- In July 2001, ENGI and Harding ESE met with NHDES to review the Site Conceptual Model and proposed Phase II supplemental investigation activities.

- ENGI and NHDES met in August 2001 to discuss the overall site objectives.

- In September 2001, Harding ESE, on behalf of ENGI, submitted a Phase IIB Supplemental Site Investigation (SI) Scope of Work to NHDES.

- NHDES provided verbal approval for the Phase IIB Supplemental SI, and Harding ESE initiated the field program on behalf of ENGI in October 2001.

- NHDES provided written approval of the Phase IIB Supplemental SI in October 2001. A modification to the proposed scope of work relating to investigations adjacent to the gas lines was made, and verbal approval obtained, on November 19, 2001.

- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.

- ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.

- Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.

- The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.

- ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.

- By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.

- ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application administratively complete. The hearing was closed on July 26, 2004 and the

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permit was issued in September 2004. The capping and re-armoring was completed in October 2004 and Remedial Completion Report submitted to NHDES in January 2005, and subsequently approved.

- In October 2005, ENGI submitted the Terrestrial Remedial Action Plan to NHDES, and the document was deemed complete by NHDES in March 2006. NHDES requested supplemental information to be submitted before ENGI proceeded with remediation, and in 2007 ENGI gathered that additional data.

- In November 2007, ENGI submitted a Workplan for DNAPL Recovery Pilot Test to NHDES and the document was approved by NHDES on November 14, 2007.

- ENGI applied for three permits required for the implementation of the NHDES-approved DNAPL pilot testing activities: Nashua Conservation Commission Permit, Nashua Zoning Board of Appeals Permit and NHDES Dredge and Fill Permit. ENGI attended numerous hearings related to obtaining the permits and obtained the three permits on April 21, 2008, April 23, 2008 and May 31, 2008, respectively.

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI is currently completing the construction of the coal tar recovery system (i.e., the equipment that will be use to pump, collect and temporarily store the coal tar on-site) and anticipates starting coal tar recovery in late 2008.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the Fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. Pilot testing of the DNAPL recovery system in the approved RAP is on-going.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Nashua Gas Light Company built the original coal gas facility in 1852 or 1853. In 1889, the Nashua Gas Light Company merged with the Nashua Electric Company to form the Nashua Light, Heat and Power Company (NHLPC). In 1914, the NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester

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NO.

Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: The EPA made a claim against ENGI and PSNH related to the so-called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA's claim in exchange for a payment of $387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

ENGI and PSNH have entered into a confidential Site Responsibility and Indemnity Agreement effective as of September 15, 2000, which governs the financial and decision-making responsibilities of the two companies through the remainder of site study and remediation. Under this agreement, ENGI will take the lead on site investigation and remediation.

Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be paid by the defendants. Subsequent to the verdict, the London Market and ENGI entered into a confidential settlement. Century appealed to the First Circuit Court of Appeals in the summer of 2006. However, on the day its brief was due at the First Circuit, Century withdrew its appeal. Because the site has not yet been remediated, the jury was not asked to make a damage determination. Future proceedings will take place after the remedy has been approved by the NHDES to determine the indemnification amounts to be paid by Century. The New Hampshire Supreme Court's ruling on the allocation issue (discussed in the Manchester MGP summary) will affect that figure.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
KEYSPAN PROJECT DEF054

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
1	Environmental Staff Payroll	Timesheet	1,254.01			1,254.01
2	Environmental Staff Payroll	Timesheet	130.72			130.72
3	Innovative Engineering Solutions, Inc.	6404	5,432.34			5,432.34
4	Innovative Engineering Solutions, Inc.	6450	18,786.75			18,786.75
5	Innovative Engineering Solutions, Inc.	6521	6,026.87			6,026.87
6	Innovative Engineering Solutions, Inc.	6656	5,031.59			5,031.59
7	Innovative Engineering Solutions, Inc.	6799	6,045.35			6,045.35
8	Innovative Engineering Solutions, Inc.	6595	13,607.03			13,607.03
9	Innovative Engineering Solutions, Inc.	6716	32,447.06			32,447.06
10	Innovative Engineering Solutions, Inc.	6868	10,093.18			10,093.18
11						
12	T Ford Company	1000	2,540.12			2,540.12
13	New Hampshire Department of Environmental Servic	19981022-04	6,209.80			6,209.80
14						
15	**Total Pool Activity**		**107,604.82**	**-**	**(10,414.21)**	**97,190.61**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - LITIGATION
KEYSPAN PROJECT DEF049

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Century Imdemnity	2007 DNH 083	-	550,000.00		550,000.00
2						
3						
4						
5						
6						
7	McLane	2007080632	-	4,675.80		4,675.80
8	McLane	2007090776	-	809.50		809.50
9	McLane	2008030392	-	170.00		170.00
10	McLane	2007120410	-	37.00		37.00
11	McLane	2007060454	-	5,338.00		5,338.00
12						
13	**Total Pool Activity**		**-**	**561,030.30**	**(1,032,185.57)**	**(471,155.27)**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

DOVER FORMER MGP

LINE
NO.

1. SITE LOCATION: Intersection of Cocheco Street and Portland Street, Dover, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: In 1999, NHDES sent notice letters to current and former site owners and operators including: Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities (NU).; EnergyNorth Natural Gas, Inc. (ENGI); Northern Utilities, Inc.; and Central Vermont Public Service Company (CVPS). It is the company's understanding that NHDES sent a notice to the current site owner, Estelle Maglaras, earlier. NHDES designated the site DES #198401047.

3. NATURE AND SCOPE OF SITE CONTAMINATION: According to the August 2002 Supplemental Site Investigation Report, the evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - During late 1999 and early 2000, PSNH/NU took the lead on preparation of a Site Investigation Report. PSNH/NU submitted the report to NHDES and the other potentially responsible parties (PRPs) in February 2000.

   - The PRPs held meetings and discussions during 2000 regarding site responsibility and liability.

   - Following an October meeting between NHDES and PSNH/NU, ENGI, and CVPS, Metcalf & Eddy, Inc. (M&E), in December 2000, submitted a Supplemental Site Investigation Work Plan on behalf of PSNH/NU, ENGI, and CVPS to NHDES.

   - NHDES provided written comments on the Supplemental Site Investigation Work Plan in April, 2001.

   - M&E submitted a letter response to NHDES comments on the Work Plan to NHDES in early June 2001.

   - NHDES approved the Supplemental Site Investigation Work Plan and letter addendum in late June 2001.

LINE
NO.

- PSNH/NU, in conjunction with CVPS and ENGI, submitted the M&E Supplemental Site Investigation Report to the DES on August 9, 2002.

- Since 2002, PSNH has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Supplemental Site Investigation completed. Please contact PSNH or NHDES for current status.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Dover MGP, which began operation in 1850, was included in that transaction. GSI operated the Dover MGP until 1956, when it was sold to Allied New Hampshire Gas Company (Allied). Approximately 10 months after that sale, the MGP was shut down when natural gas arrived in Dover. Allied merged into Northern Utilities in 1969, and Northern Utilities continued to own the property until 1978. At that time, the property was sold to Estelle Maglaras, the current owner. The majority of the property is used by the Maglaras family as a marina and boatyard. Northern Utilities, Inc. maintains a regulator station on a small portion of the former MGP property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Mediation between PSNH, ENGI, CVPS and Northern Utilities for allocation was undertaken in the fall of 2001 but was not successful. Since that time, PSNH reached a confidential settlement and allocation with CVPS, and has taken the lead on site investigation and remediation activities. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments. PSNH and ENGI have attempted to negotiate an allocation but thus far have been unsuccessful.

   Insurance recovery efforts resulted in several confidential settlements. Trial was conducted in the United States District Court in February, 2005. At the close of the defendant's case, the court directed a verdict in ENGI's favor on the issue of coverage determining that the defendant is liable for environmental costs related to the site. In May, 2005, the court ordered Century Indemnity to reimburse ENGI's attorneys' fees and costs associated with the litigation. In June 2005, the Court issued an Amended Judgment awarding fees to ENGI. Century appealed the Amended Judgment and oral argument was heard in January 2006.

LINE
NO.

Century's appeal was denied by the Court in June 2006, and ENGI was ultimately awarded its attorneys fees associated with that appeal.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
SITE NAME: DOVER - REMEDIATION
KEYSPAN PROJECT DEF059

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1			-			
2			-			
3	**NO ACTIVITY FOR THIS PERIOD**					
4						
5						
6						
7	**Total Pool Activity**		**-**	**-**	**-**	**-**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
DOVER - LITIGATION
KEYSPAN PROJECT DEF060

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1						
2			-			-
3	**Total Pool Activity**		**-**	**-**	**(2,133.18)**	**(2,133.18)**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

KEENE FORMER MGP

LINE
NO.

1. SITE LOCATION: 207 and 227 Emerald Street, Keene, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: Information on site investigation activities comes from reports prepared by Public Service Company of New Hampshire (PSNH). It is apparent the New Hampshire Department of Environmental Services (NHDES) first investigated Mill Creek adjacent to the former Keene Manufactured Gas Plant (MGP) in 1986. PSNH, a former owner and operator, and its parent company, Northeast Utilities Service Company (NU), conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a Site Investigation in 1996 in response to a notice letter from the NHDES, which designated the site DES # 199412009. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. Although it does not appear to have been actively involved in the site study, Keene Gas Corporation (KGC) received a notice letter from NHDES in January 1999. In response to a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Natural Gas, Inc. (ENGI) in April 2001. ENGI responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI entered into a confidential agreement with PSNH relative to the development and execution of a Remedial Action Plan (RAP) for the aquatic portion of the site in January 2005. Subsequently, in March 2005, ENGI and PSNH/NU submitted a Scope of Work for the ecological evaluation of the Ashuelot River Sediments to NHDES, and met with NHDES on April 25, 2005 to discuss the conceptual RAP (consisting of sediment removal and stream bed restoration) for Mill Creek/Ashuelot River. NHDES approved the scope of the ecological evaluation, and it was conducted in 2005. In February 2006, PSNH submitted a scope of work for a supplemental investigation of the Ashuelot River, which was approved by NHDES in April 2006. This work was completed and in response in February 2007 NHDES requested a Remedial Action Plan for Mill Creek and a portion of the Ashuelot River.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Remediation of the terrestrial portion of the site was completed by PSNH/NU in 2004/2005. An ecological risk assessment in support of a Remedial Action Plan for the Ashuelot River and Mill Creek

portions of the site was conducted jointly by ENGI and PSNH/NU in 2005. A supplemental investigation of the Ashuelot River to support the preparation of a Remedial Action Plan (RAP) was completed in 2007 and NHDES has requested PSNH/NU submit the RAP for Mill Creek and portions of the Ashuelot River in 2007. NHDES files indicate that the RAP was submitted by PSNH in 2008. PSNH has taken the lead on investigation at this Site, and so has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: Given its status at the site, ENGI has not yet conducted a thorough evaluation of its history. It is known that the plant became operational in approximately 1860 and operated as a manufactured gas plant until 1952, after which it was converted to butane and later to propane. Gas Service, Inc., a predecessor of ENGI, owned the former MGP between October 1945 and its closure in 1952. Gas Service continued to own the property until it was sold to KGC in 1979. KGC continues to operate a propane-air plant at the site. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on site history, use and ownership.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS:

Insurance recovery claims are underway, and confidential settlements have been entered into with all but one defendant. Trial had been scheduled for October 2006 against the sole remaining insurance company defendant, Century Indemnity, however that trial was put off while awaiting a ruling on an issue of law in the Manchester MGP litigation by the New Hampshire Supreme Court. The Supreme Court has since ruled on the appropriate method of allocating indemnification obligations among multiple insurers and the applicability of the New Hampshire attorneys fees statute, RSA 491:22-a, which is relevant to the Keene case. In that case, EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007), the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and

done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.
It is anticipated the court will lift the stay during 2008.

ENGI intervened in Docket DE 98-123, the proceeding in which the Commission considered the proposed transfer of operating assets from Keene Gas Corporation (KGC) to New Hampshire Gas Corporation (NHGC). ENGI opposed the proposed transfer because it was concerned that the transfer was likely to create a significant, and possibly insurmountable, obstacle to the potential for KGC customers to share in responsibility for any costs associated with environmental liabilities at the Keene MGP site. At the time, ENGI had not been named as a potentially responsible party for the Keene MGP site, nor had it been notified by any PRP of any claimed liability for the site. Nevertheless, ENGI was aware of the possibility that it would receive such a notice at some point in the future. In the KGC/NHGC proceeding, ENGI proposed that the Commission condition any approval of the proposed transfer on NHGC's willingness to assume responsibility for KGC's liability with regard to the site. The Commission ultimately approved the transfer of assets without imposing such a condition, finding among other things that liability for environmental contamination at the Keene MGP site remained speculative at that time and that assignment of any such liability to various parties was not appropriate for determination by the Commission.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - REMEDIATION
KEYSPAN PROJECT DEF055

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Environmental Staff Payroll	Timesheet	32.36			32.36
2			-			-
3	**Total Pool Activity**		**32.36**	**-**	**-**	**32.36**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - LITIGATION
KEYSPAN PROJECT DEF071

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	McLane	2007090517	387.00			387.00
2	McLane	2007090777	-	55.50		55.50
3	McLane	2007111390	-	882.00		882.00
4	McLane	2007120694	-	234.50		234.50
5			-	-		-
6	**Total Pool Activity**		**387.00**	**1,172.00**	**-**	**1,559.00**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
KEYSPAN PROJECT DEF064

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	American Institute of Professional Geologists	15189	35.00			35.00
2	Dickstein Shapiro	2209363	-	5,042.14		5,042.14
3	Environmental Staff Payroll	Timesheet	3,477.03			3,477.03
4	Environmental Staff Payroll	Timesheet	10,354.93			10,354.93
5	Environmental Staff Travel Expenses	EXP 0235174	1.40			1.40
6	Environmental Staff Travel Expenses	EXP 0243633	39.62			39.62
7	Environmental Staff Travel Expenses	EXP 0245881	20.95			20.95
8	Environmental Staff Travel Expenses	EXP 0245881	2.48			2.48
9	Environmental Staff Travel Expenses	EXP 0242567	44.90			44.90
10	Environmental Staff Travel Expenses	EXP 0243074	30.00			30.00
11	Ikon Office Solutions	BOG07080213	1,503.81			1,503.81
12	LECG, LLC	82477	975.00			975.00
13	LECG, LLC	76174	-	489.58		489.58
14	LECG, LLC	80511	-	61.82		61.82
15	LECG, LLC	85816	-	130.19		130.19
16	LECG, LLC	89248	-	466.92		466.92
17	LECG, LLC	89115	-	547.45		547.45
18	LECG, LLC	91252	-	5,187.35		5,187.35
19	LECG, LLC	94168	-	97.40		97.40
20	LECG, LLC	94165	-	471.35		471.35
21	McLane	2007110405	-	3,517.62		3,517.62
22	McLane	2008050048	4,316.00			4,316.00
23	McLane	2008040243	170.00			170.00
24	McLane	2007070736	4,108.12			4,108.12
25	McLane	2007080884	305.50			305.50
26	McLane	2007060455	106.25			106.25
27	McLane	2007080885	472.50			472.50
28	McLane	2007090518	2,463.30			2,463.30
29	McLane	2007110403	787.50			787.50
30	McLane	2008020918	4,487.50			4,487.50
31	McLane	2008030388	1,054.00			1,054.00
32	Interest on Over Recovery Balance Sep 06 - Jul 08		(215,756.00)			(215,756.00)
32						
33	**Total Pool Activity**		**(181,000.21)**	**16,011.82**	**-**	**(164,988.39)**

ATTACHMENT D
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.12 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	$9.72 MMBTU of Peak MDQ.

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH

Calculation of Supplier Balancing Charge

Rate: **$0.12 /MMBtu**

	Rate	Volume	Total	
Injection Cost	$0.0102	**550,177**	$5,612	
Withdrawal Cost	$0.0102	**300,124**	$3,061	
Delivery Rate	$0.0378	300,124	$11,347	
FTA Demand Charge	$0.1936	300,124	$58,117	
FTA Commodity Charge	$0.0834	300,124	$25,030	
		Total Cost	$103,168	
	Absolute Value of the	Sendout Error	**850,300**	MMBtu
		Rate	$ 0.12	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

TGP FSMA Injection Charge	$0.0102	/ MMBtu
TGP FSMA Withdrawal Charge	$0.0102	/ MMBtu
TGP FSMA Deliverability Charge	$1.15	/ MMBtu per month
	$0.0378	/ MMBtu per day
TGP Z4-6 Demand Charge	$5.89	/ MMBtu per month
	$0.1936	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.0834	/ MMBtu

EnergyNorth Natural Gas Inc.
d/b/a National Grid NH

Calculation of Supplier Balancing Charge

Estimated Monthly Imbalances

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov	814	806	8	1,430,461	1,418,296	12,165	136,858	74,511	62,346
Dec	1,231	1,201	30	2,230,318	2,181,741	48,577	129,539	89,058	40,481
Jan	1,181	1,148	33	2,208,413	2,153,360	55,053	155,148	105,100	50,048
Feb	1,048	1,029	19	2,023,906	1,997,191	26,716	108,434	67,575	40,859
Mar	1,014	971	43	1,844,895	1,782,623	62,272	76,754	69,513	7,241
Apr	518	491	27	943,411	908,365	35,046	105,138	70,092	35,046
May	232	205	27	524,127	502,564	21,563	47,120	34,341	12,778
Jun	51	64	-13	321,086	326,077	-4,991	15,741	5,375	10,366
Jul	8	4	4	299,431	299,431	0	0	0	0
Aug	24	25	-1	299,422	299,422	0	0	0	0
Sep	80	99	-19	336,624	343,909	-7,285	16,488	4,601	11,887
Oct	296	295	1	566,093	565,155	938	59,081	30,009	29,072
Total	**6,497**	**6,338**	**159**	**13,028,189**	**12,778,136**	**250,053**	**850,300**	**550,177**	**300,124**

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
May 1, 07	13	8	5	21,313	17,320	3,993	3,993	3,993	0
May 2, 07	15	12	3	22,910	20,514	2,396	2,396	2,396	0
May 3, 07	13	10	3	21,313	18,917	2,396	2,396	2,396	0
May 4, 07	13	12	1	21,313	20,514	799	799	799	0
May 5, 07	16	11	5	23,709	19,715	3,993	3,993	3,993	0
May 6, 07	15	17	-2	22,910	24,507	-1,597	1,597	0	1,597
May 7, 07	5	5	0	14,924	14,924	0	0	0	0
May 8, 07	0	0	0	10,930	10,930	0	0	0	0
May 9, 07	0	0	0	10,930	10,930	0	0	0	0
May 10, 07	0	0	0	10,930	10,930	0	0	0	0
May 11, 07	1	0	1	11,729	10,930	799	799	799	0
May 12, 07	11	9	2	19,715	18,118	1,597	1,597	1,597	0
May 13, 07	15	12	3	22,910	20,514	2,396	2,396	2,396	0
May 14, 07	10	4	6	18,917	14,125	4,792	4,792	4,792	0
May 15, 07	0	0	0	10,930	10,930	0	0	0	0
May 16, 07	11	17	-6	19,715	24,507	-4,792	4,792	0	4,792
May 17, 07	16	19	-3	23,709	26,105	-2,396	2,396	0	2,396
May 18, 07	19	21	-2	26,105	27,702	-1,597	1,597	0	1,597
May 19, 07	12	11	1	20,514	19,715	799	799	799	0
May 20, 07	15	10	5	22,910	18,917	3,993	3,993	3,993	0
May 21, 07	13	11	2	21,313	19,715	1,597	1,597	1,597	0
May 22, 07	8	6	2	17,320	15,722	1,597	1,597	1,597	0
May 23, 07	4	5	-1	14,125	14,924	-799	799	0	799
May 24, 07	0	0	0	10,930	10,930	0	0	0	0
May 25, 07	0	0	0	10,930	10,930	0	0	0	0
May 26, 07	0	0	0	10,930	10,930	0	0	0	0
May 27, 07	1	2	-1	11,729	12,528	-799	799	0	799
May 28, 07	2	0	2	12,528	10,930	1,597	1,597	1,597	0
May 29, 07	2	0	2	12,528	10,930	1,597	1,597	1,597	0
May 30, 07	0	0	0	10,930	10,930	0	0	0	0
May 31, 07	2	3	-1	12,528	13,326	-799	799	0	799
Jun 1, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 2, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 3, 07	2	13	-11	10,818	15,041	-4,223	4,223	0	4,223
Jun 4, 07	2	8	-6	10,818	13,122	-2,304	2,304	0	2,304
Jun 5, 07	1	2	-1	10,434	10,818	-384	384	0	384
Jun 6, 07	8	9	-1	13,122	13,506	-384	384	0	384
Jun 7, 07	1	1	0	10,434	10,434	0	0	0	0
Jun 8, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 9, 07	6	5	1	12,354	11,970	384	384	384	0
Jun 10, 07	4	0	4	11,586	10,050	1,536	1,536	1,536	0
Jun 11, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 12, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 13, 07	6	9	-3	12,354	13,506	-1,152	1,152	0	1,152
Jun 14, 07	5	9	-4	11,970	13,506	-1,536	1,536	0	1,536
Jun 15, 07	4	0	4	11,586	10,050	1,536	1,536	1,536	0
Jun 16, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 17, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 18, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 19, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 20, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 21, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 22, 07	4	5	-1	11,586	11,970	-384	384	0	384
Jun 23, 07	3	3	0	11,202	11,202	0	0	0	0
Jun 24, 07	2	0	2	10,818	10,050	768	768	768	0
Jun 25, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 26, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 27, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 28, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 29, 07	0	0	0	10,050	10,050	0	0	0	0
Jun 30, 07	3	0	3	11,202	10,050	1,152	1,152	1,152	0
Jul 1, 07	5	4	1	9,659	9,659	0	0	0	0
Jul 2, 07	3	0	3	9,659	9,659	0	0	0	0
Jul 3, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 4, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 5, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 6, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 7, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 8, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 9, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 10, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 11, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 12, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 13, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 14, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 15, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 16, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 17, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 18, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 19, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 20, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 21, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 22, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 23, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 24, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 25, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 26, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 27, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 28, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 29, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 30, 07	0	0	0	9,659	9,659	0	0	0	0
Jul 31, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 1, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 2, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 3, 07	0	0	0	9,659	9,659	0	0	0	0

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Aug 4, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 5, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 6, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 7, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 8, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 9, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 10, 07	1	5	-4	9,659	9,659	0	0	0	0
Aug 11, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 12, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 13, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 14, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 15, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 16, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 17, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 18, 07	5	4	1	9,659	9,659	0	0	0	0
Aug 19, 07	6	4	2	9,659	9,659	0	0	0	0
Aug 20, 07	4	5	-1	9,659	9,659	0	0	0	0
Aug 21, 07	4	6	-2	9,659	9,659	0	0	0	0
Aug 22, 07	4	1	3	9,659	9,659	0	0	0	0
Aug 23, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 24, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 25, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 26, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 27, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 28, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 29, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 30, 07	0	0	0	9,659	9,659	0	0	0	0
Aug 31, 07	0	0	0	9,659	9,659	0	0	0	0
Sep 1, 07	1	2	-1	10,582	10,965	-383	383	0	383
Sep 2, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 3, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 4, 07	0	2	-2	10,198	10,965	-767	767	0	767
Sep 5, 07	2	4	-2	10,965	11,732	-767	767	0	767
Sep 6, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 7, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 8, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 9, 07	0	6	-6	10,198	12,499	-2,301	2,301	0	2,301
Sep 10, 07	0	4	-4	10,198	11,732	-1,534	1,534	0	1,534
Sep 11, 07	0	5	-5	10,198	12,115	-1,917	1,917	0	1,917
Sep 12, 07	4	4	0	11,732	11,732	0	0	0	0
Sep 13, 07	7	4	3	12,882	11,732	1,150	1,150	1,150	0
Sep 14, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 15, 07	10	11	-1	14,033	14,416	-383	383	0	383
Sep 16, 07	14	12	2	15,566	14,800	767	767	767	0
Sep 17, 07	8	11	-3	13,266	14,416	-1,150	1,150	0	1,150
Sep 18, 07	8	11	-3	13,266	14,416	-1,150	1,150	0	1,150
Sep 19, 07	3	5	-2	11,349	12,115	-767	767	0	767
Sep 20, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 21, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 22, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 23, 07	2	0	2	10,965	10,198	767	767	767	0
Sep 24, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 25, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 26, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 27, 07	0	0	0	10,198	10,198	0	0	0	0
Sep 28, 07	5	1	4	12,115	10,582	1,534	1,534	1,534	0
Sep 29, 07	8	7	1	13,266	12,882	383	383	383	0
Sep 30, 07	8	10	-2	13,266	14,033	-767	767	0	767
Oct 1, 07	5	10	-5	13,996	18,685	-4,689	4,689	0	4,689
Oct 2, 07	4	3	1	13,058	12,120	938	938	938	0
Oct 3, 07	0	0	0	9,307	9,307	0	0	0	0
Oct 4, 07	0	0	0	9,307	9,307	0	0	0	0
Oct 5, 07	0	0	0	9,307	9,307	0	0	0	0
Oct 6, 07	0	0	0	9,307	9,307	0	0	0	0
Oct 7, 07	4	9	-5	13,058	17,747	-4,689	4,689	0	4,689
Oct 8, 07	1	10	-9	10,244	18,685	-8,440	8,440	0	8,440
Oct 9, 07	10	10	0	18,685	18,685	0	0	0	0
Oct 10, 07	11	9	2	19,622	17,747	1,876	1,876	1,876	0
Oct 11, 07	8	10	-2	16,809	18,685	-1,876	1,876	0	1,876
Oct 12, 07	17	17	0	25,249	25,249	0	0	0	0
Oct 13, 07	16	16	0	24,311	24,311	0	0	0	0
Oct 14, 07	18	18	0	26,187	26,187	0	0	0	0
Oct 15, 07	16	14	2	24,311	22,436	1,876	1,876	1,876	0
Oct 16, 07	18	18	0	26,187	26,187	0	0	0	0
Oct 17, 07	11	10	1	19,622	18,685	938	938	938	0
Oct 18, 07	1	5	-4	10,244	13,996	-3,751	3,751	0	3,751
Oct 19, 07	0	0	0	9,307	9,307	0	0	0	0
Oct 20, 07	5	5	0	13,996	13,996	0	0	0	0
Oct 21, 07	7	4	3	15,871	13,058	2,813	2,813	2,813	0
Oct 22, 07	6	0	6	14,933	9,307	5,627	5,627	5,627	0
Oct 23, 07	8	0	8	16,809	9,307	7,502	7,502	7,502	0
Oct 24, 07	15	13	2	23,374	21,498	1,876	1,876	1,876	0
Oct 25, 07	20	18	2	28,062	26,187	1,876	1,876	1,876	0
Oct 26, 07	13	12	1	21,498	20,560	938	938	938	0
Oct 27, 07	9	8	1	17,747	16,809	938	938	938	0
Oct 28, 07	19	22	-3	27,125	29,938	-2,813	2,813	0	2,813
Oct 29, 07	24	27	-3	31,814	34,627	-2,813	2,813	0	2,813
Oct 30, 07	20	18	2	28,062	26,187	1,876	1,876	1,876	0
Oct 31, 07	10	9	1	18,685	17,747	938	938	938	0
Nov 1, 07	19	18	1	35,314	33,794	1,521	1,521	1,521	0
Nov 2, 07	23	20	3	41,397	36,835	4,562	4,562	4,562	0
Nov 3, 07	27	22	5	47,479	39,876	7,603	7,603	7,603	0
Nov 4, 07	22	22	0	39,876	39,876	0	0	0	0
Nov 5, 07	20	16	4	36,835	30,752	6,083	6,083	6,083	0
Nov 6, 07	25	26	-1	44,438	45,959	-1,521	1,521	0	1,521
Nov 7, 07	28	27	1	49,000	47,479	1,521	1,521	1,521	0

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Estimated Daily Imbalances

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Nov 8, 07	31	31	0	53,562	53,562	0	0	0	0
Nov 9, 07	28	29	-1	49,000	50,521	-1,521	1,521	0	1,521
Nov 10, 07	33	32	1	56,603	55,083	1,521	1,521	1,521	0
Nov 11, 07	29	33	-4	50,521	56,603	-6,083	6,083	0	6,083
Nov 12, 07	25	24	1	44,438	42,917	1,521	1,521	1,521	0
Nov 13, 07	21	25	-4	38,355	44,438	-6,083	6,083	0	6,083
Nov 14, 07	14	9	5	27,711	20,108	7,603	7,603	7,603	0
Nov 15, 07	24	20	4	42,917	36,835	6,083	6,083	6,083	0
Nov 16, 07	32	30	2	55,083	52,041	3,041	3,041	3,041	0
Nov 17, 07	31	33	-2	53,562	56,603	-3,041	3,041	0	3,041
Nov 18, 07	35	33	2	59,644	56,603	3,041	3,041	3,041	0
Nov 19, 07	35	32	3	59,644	55,083	4,562	4,562	4,562	0
Nov 20, 07	28	32	-4	49,000	55,083	-6,083	6,083	0	6,083
Nov 21, 07	25	28	-3	44,438	49,000	-4,562	4,562	0	4,562
Nov 22, 07	18	26	-8	33,794	45,959	-12,165	12,165	0	12,165
Nov 23, 07	32	39	-7	55,083	65,727	-10,644	10,644	0	10,644
Nov 24, 07	30	36	-6	52,041	61,165	-9,124	9,124	0	9,124
Nov 25, 07	26	27	-1	45,959	47,479	-1,521	1,521	0	1,521
Nov 26, 07	23	22	1	41,397	39,876	1,521	1,521	1,521	0
Nov 27, 07	30	24	6	52,041	42,917	9,124	9,124	9,124	0
Nov 28, 07	35	31	4	59,644	53,562	6,083	6,083	6,083	0
Nov 29, 07	31	27	4	53,562	47,479	6,083	6,083	6,083	0
Nov 30, 07	34	32	2	58,124	55,083	3,041	3,041	3,041	0
Dec 1, 07	47	47	0	83,751	83,751	0	0	0	0
Dec 2, 07	39	41	-2	70,797	74,035	-3,238	3,238	0	3,238
Dec 3, 07	38	40	-2	69,177	72,416	-3,238	3,238	0	3,238
Dec 4, 07	41	45	-4	74,035	80,512	-6,477	6,477	0	6,477
Dec 5, 07	40	42	-2	72,416	75,654	-3,238	3,238	0	3,238
Dec 6, 07	44	45	-1	78,893	80,512	-1,619	1,619	0	1,619
Dec 7, 07	38	41	-3	69,177	74,035	-4,858	4,858	0	4,858
Dec 8, 07	39	36	3	70,797	65,939	4,858	4,858	4,858	0
Dec 9, 07	42	38	4	75,654	69,177	6,477	6,477	6,477	0
Dec 10, 07	40	45	-5	72,416	80,512	-8,096	8,096	0	8,096
Dec 11, 07	34	32	2	62,700	59,462	3,238	3,238	3,238	0
Dec 12, 07	38	35	3	69,177	64,320	4,858	4,858	4,858	0
Dec 13, 07	43	45	-2	77,274	80,512	-3,238	3,238	0	3,238
Dec 14, 07	40	37	3	72,416	67,558	4,858	4,858	4,858	0
Dec 15, 07	50	49	1	88,608	86,989	1,619	1,619	1,619	0
Dec 16, 07	44	44	0	78,893	78,893	0	0	0	0
Dec 17, 07	50	49	1	88,608	86,989	1,619	1,619	1,619	0
Dec 18, 07	48	49	-1	85,370	86,989	-1,619	1,619	0	1,619
Dec 19, 07	38	38	0	69,177	69,177	0	0	0	0
Dec 20, 07	39	40	-1	70,797	72,416	-1,619	1,619	0	1,619
Dec 21, 07	46	46	0	82,131	82,131	0	0	0	0
Dec 22, 07	36	37	-1	65,939	67,558	-1,619	1,619	0	1,619
Dec 23, 07	28	27	1	52,985	51,366	1,619	1,619	1,619	0
Dec 24, 07	34	29	5	62,700	54,604	8,096	8,096	8,096	0
Dec 25, 07	39	35	4	70,797	64,320	6,477	6,477	6,477	0
Dec 26, 07	38	31	7	69,177	57,843	11,335	11,335	11,335	0
Dec 27, 07	36	32	4	65,939	59,462	6,477	6,477	6,477	0
Dec 28, 07	33	29	4	61,081	54,604	6,477	6,477	6,477	0
Dec 29, 07	36	28	8	65,939	52,985	12,954	12,954	12,954	0
Dec 30, 07	36	31	5	65,939	57,843	8,096	8,096	8,096	0
Dec 31, 07	37	38	-1	67,558	69,177	-1,619	1,619	0	1,619
Jan 1, 08	39	35	4	72,746	66,073	6,673	6,673	6,673	0
Jan 2, 08	45	54	-9	82,756	97,770	-15,014	15,014	0	15,014
Jan 3, 08	58	61	-3	104,443	109,448	-5,005	5,005	0	5,005
Jan 4, 08	41	43	-2	76,082	79,419	-3,337	3,337	0	3,337
Jan 5, 08	37	32	5	69,409	61,068	8,341	8,341	8,341	0
Jan 6, 08	29	33	-4	56,063	62,736	-6,673	6,673	0	6,673
Jan 7, 08	25	29	-4	49,390	56,063	-6,673	6,673	0	6,673
Jan 8, 08	18	15	3	37,712	32,708	5,005	5,005	5,005	0
Jan 9, 08	24	20	4	47,722	41,049	6,673	6,673	6,673	0
Jan 10, 08	29	27	2	56,063	52,727	3,337	3,337	3,337	0
Jan 11, 08	28	30	-2	54,395	57,732	-3,337	3,337	0	3,337
Jan 12, 08	32	31	1	61,068	59,400	1,668	1,668	1,668	0
Jan 13, 08	35	31	4	66,073	59,400	6,673	6,673	6,673	0
Jan 14, 08	39	40	-1	72,746	74,414	-1,668	1,668	0	1,668
Jan 15, 08	42	39	3	77,751	72,746	5,005	5,005	5,005	0
Jan 16, 08	41	43	-2	76,082	79,419	-3,337	3,337	0	3,337
Jan 17, 08	38	35	3	71,078	66,073	5,005	5,005	5,005	0
Jan 18, 08	38	33	5	71,078	62,736	8,341	8,341	8,341	0
Jan 19, 08	41	37	4	76,082	69,409	6,673	6,673	6,673	0
Jan 20, 08	50	49	1	91,097	89,429	1,668	1,668	1,668	0
Jan 21, 08	49	50	-1	89,429	91,097	-1,668	1,668	0	1,668
Jan 22, 08	43	34	9	79,419	64,405	15,014	15,014	15,014	0
Jan 23, 08	42	39	3	77,751	72,746	5,005	5,005	5,005	0
Jan 24, 08	48	46	2	87,760	84,424	3,337	3,337	3,337	0
Jan 25, 08	45	44	1	82,756	81,087	1,668	1,668	1,668	0
Jan 26, 08	43	39	4	79,419	72,746	6,673	6,673	6,673	0
Jan 27, 08	41	43	-2	76,082	79,419	-3,337	3,337	0	3,337
Jan 28, 08	37	36	1	69,409	67,741	1,668	1,668	1,668	0
Jan 29, 08	30	28	2	57,732	54,395	3,337	3,337	3,337	0
Jan 30, 08	36	35	1	67,741	66,073	1,668	1,668	1,668	0
Jan 31, 08	38	37	1	71,078	69,409	1,668	1,668	1,668	0
Feb 1, 08	34	31	3	64,154	59,440	4,715	4,715	4,715	0
Feb 2, 08	33	29	4	62,583	56,297	6,286	6,286	6,286	0
Feb 3, 08	33	32	1	62,583	61,011	1,572	1,572	1,572	0
Feb 4, 08	32	30	2	61,011	57,868	3,143	3,143	3,143	0
Feb 5, 08	27	31	-4	53,154	59,440	-6,286	6,286	0	6,286
Feb 6, 08	34	32	2	64,154	61,011	3,143	3,143	3,143	0
Feb 7, 08	41	40	1	75,155	73,583	1,572	1,572	1,572	0
Feb 8, 08	40	39	1	73,583	72,012	1,572	1,572	1,572	0
Feb 9, 08	32	33	-1	61,011	62,583	-1,572	1,572	0	1,572
Feb 10, 08	41	44	-3	75,155	79,869	-4,715	4,715	0	4,715
Feb 11, 08	42	49	-7	76,726	87,727	-11,001	11,001	0	11,001

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Estimated Daily Imbalances

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Feb 12, 08	40	40	0	73,583	73,583	0	0	0	0
Feb 13, 08	38	33	5	70,440	62,583	7,858	7,858	7,858	0
Feb 14, 08	40	36	4	73,583	67,297	6,286	6,286	6,286	0
Feb 15, 08	40	37	3	73,583	68,869	4,715	4,715	4,715	0
Feb 16, 08	48	47	1	86,155	84,584	1,572	1,572	1,572	0
Feb 17, 08	31	28	3	59,440	54,725	4,715	4,715	4,715	0
Feb 18, 08	30	22	8	57,868	45,296	12,572	12,572	12,572	0
Feb 19, 08	36	36	0	67,297	67,297	0	0	0	0
Feb 20, 08	42	44	-2	76,726	79,869	-3,143	3,143	0	3,143
Feb 21, 08	44	44	0	79,869	79,869	0	0	0	0
Feb 22, 08	39	42	-3	72,012	76,726	-4,715	4,715	0	4,715
Feb 23, 08	39	41	-2	72,012	75,155	-3,143	3,143	0	3,143
Feb 24, 08	37	37	0	68,869	68,869	0	0	0	0
Feb 25, 08	35	31	4	65,726	59,440	6,286	6,286	6,286	0
Feb 26, 08	32	31	1	61,011	59,440	1,572	1,572	1,572	0
Feb 27, 08	38	40	-2	70,440	73,583	-3,143	3,143	0	3,143
Feb 28, 08	50	50	0	89,298	89,298	0	0	0	0
Feb 29, 08	42	44	-2	76,726	79,869	-3,143	3,143	0	3,143
Mar 1, 08	37	35	2	66,613	63,717	2,896	2,896	2,896	0
Mar 2, 08	38	39	-1	68,062	69,510	-1,448	1,448	0	1,448
Mar 3, 08	28	21	7	53,580	43,443	10,137	10,137	10,137	0
Mar 4, 08	29	26	3	55,028	50,684	4,345	4,345	4,345	0
Mar 5, 08	31	30	1	57,924	56,476	1,448	1,448	1,448	0
Mar 6, 08	31	31	0	57,924	57,924	0	0	0	0
Mar 7, 08	27	29	-2	52,132	55,028	-2,896	2,896	0	2,896
Mar 8, 08	30	29	1	56,476	55,028	1,448	1,448	1,448	0
Mar 9, 08	40	38	2	70,958	68,062	2,896	2,896	2,896	0
Mar 10, 08	39	39	0	69,510	69,510	0	0	0	0
Mar 11, 08	31	31	0	57,924	57,924	0	0	0	0
Mar 12, 08	34	33	1	62,269	60,821	1,448	1,448	1,448	0
Mar 13, 08	33	31	2	60,821	57,924	2,896	2,896	2,896	0
Mar 14, 08	26	26	0	50,684	50,684	0	0	0	0
Mar 15, 08	31	29	2	57,924	55,028	2,896	2,896	2,896	0
Mar 16, 08	33	31	2	60,821	57,924	2,896	2,896	2,896	0
Mar 17, 08	35	33	2	63,717	60,821	2,896	2,896	2,896	0
Mar 18, 08	29	28	1	55,028	53,580	1,448	1,448	1,448	0
Mar 19, 08	30	29	1	56,476	55,028	1,448	1,448	1,448	0
Mar 20, 08	30	30	0	56,476	56,476	0	0	0	0
Mar 21, 08	37	35	2	66,613	63,717	2,896	2,896	2,896	0
Mar 22, 08	35	32	3	63,717	59,373	4,345	4,345	4,345	0
Mar 23, 08	37	35	2	66,613	63,717	2,896	2,896	2,896	0
Mar 24, 08	36	31	5	65,165	57,924	7,241	7,241	7,241	0
Mar 25, 08	29	29	0	55,028	55,028	0	0	0	0
Mar 26, 08	26	22	4	50,684	44,891	5,793	5,793	5,793	0
Mar 27, 08	26	24	2	50,684	47,787	2,896	2,896	2,896	0
Mar 28, 08	33	33	0	60,821	60,821	0	0	0	0
Mar 29, 08	39	38	1	69,510	68,062	1,448	1,448	1,448	0
Mar 30, 08	32	30	2	59,373	56,476	2,896	2,896	2,896	0
Mar 31, 08	23	25	-2	46,339	49,235	-2,896	2,896	0	2,896
Apr 1, 08	14	14	0	27,008	27,008	0	0	0	0
Apr 2, 08	27	29	-2	45,232	48,036	-2,804	2,804	0	2,804
Apr 3, 08	22	23	-1	38,223	39,624	-1,402	1,402	0	1,402
Apr 4, 08	29	26	3	48,036	43,830	4,206	4,206	4,206	0
Apr 5, 08	25	22	3	42,428	38,223	4,206	4,206	4,206	0
Apr 6, 08	25	28	-3	42,428	46,634	-4,206	4,206	0	4,206
Apr 7, 08	24	27	-3	41,026	45,232	-4,206	4,206	0	4,206
Apr 8, 08	23	24	-1	39,624	41,026	-1,402	1,402	0	1,402
Apr 9, 08	16	13	3	29,812	25,606	4,206	4,206	4,206	0
Apr 10, 08	16	12	4	29,812	24,204	5,607	5,607	5,607	0
Apr 11, 08	23	20	3	39,624	35,419	4,206	4,206	4,206	0
Apr 12, 08	24	13	11	41,026	25,606	15,420	15,420	15,420	0
Apr 13, 08	23	24	-1	39,624	41,026	-1,402	1,402	0	1,402
Apr 14, 08	26	23	3	43,830	39,624	4,206	4,206	4,206	0
Apr 15, 08	21	19	2	36,821	34,017	2,804	2,804	2,804	0
Apr 16, 08	13	13	0	25,606	25,606	0	0	0	0
Apr 17, 08	12	11	1	24,204	22,802	1,402	1,402	1,402	0
Apr 18, 08	4	2	2	12,989	10,186	2,804	2,804	2,804	0
Apr 19, 08	13	10	3	25,606	21,400	4,206	4,206	4,206	0
Apr 20, 08	13	13	0	25,606	25,606	0	0	0	0
Apr 21, 08	11	9	2	22,802	19,999	2,804	2,804	2,804	0
Apr 22, 08	8	1	7	18,597	8,784	9,813	9,813	9,813	0
Apr 23, 08	0	0	0	7,382	7,382	0	0	0	0
Apr 24, 08	6	7	-1	15,793	17,195	-1,402	1,402	0	1,402
Apr 25, 08	10	10	0	21,400	21,400	0	0	0	0
Apr 26, 08	17	14	3	31,213	27,008	4,206	4,206	4,206	0
Apr 27, 08	16	18	-2	29,812	32,615	-2,804	2,804	0	2,804
Apr 28, 08	14	19	-5	27,008	34,017	-7,009	7,009	0	7,009
Apr 29, 08	20	22	-2	35,419	38,223	-2,804	2,804	0	2,804
Apr 30, 08	20	24	-4	35,419	41,026	-5,607	5,607	0	5,607
May	232	205	27	524,127	502,564	21,563	47,120	34,341	12,778
Jun	51	64	-13	321,086	326,077	-4,991	15,741	5,375	10,366
Jul	8	4	4	299,431	299,431	0	0	0	0
Aug	24	25	-1	299,422	299,422	0	0	0	0
Sep	80	99	-19	336,624	343,909	-7,285	16,488	4,601	11,887
Oct	296	295	1	566,093	565,155	938	59,081	30,009	29,072
Nov	814	806	8	1,430,461	1,418,296	12,165	136,858	74,511	62,346
Dec	1,231	1,201	30	2,230,318	2,181,741	48,577	129,539	89,058	40,481
Jan	1,181	1,148	33	2,208,413	2,153,360	55,053	155,148	105,100	50,048
Feb	1,090	1,073	17	2,023,906	1,997,191	26,716	108,434	67,575	40,859
Mar	995	952	43	1,844,895	1,782,623	62,272	76,754	69,513	7,241
Apr	515	490	25	943,411	908,365	35,046	105,138	70,092	35,046
Total	6,517	6,362	155	13,028,189	12,778,136	250,053	850,300	550,177	300,124
Datacheck	0	0	0	0	0	0	0	0	0

ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		145,100	Dekatherm	
2					
3	Pipeline MDQ				Attachment A: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 33371	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
10			49,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		67,267	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
24	Gas Supply		$1,579,133		Attachment B Line 11
25	Indirect Production & Storage Capacity		$2,105,212		Attachment D: Order No. 23,675 (page 15), Docket DG 00-063,
26	Granite Ridge		$240,000		Attachment B Line 1
27	Total		$3,924,345		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$58.34		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$9.72**	**/Dekatherm**	Line 29 divided by 6 month

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ENERGY NORTH NATURAL GAS

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	46.00%	33.00%
Storage	16.00%	20.00%
Peaking	38.00%	47.00%
TOTAL:	100.00%	100.00%

Attachment A

Capacity Resources effective November 1, 2008:

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE II*	Supply at Waddington		4,000		$9.7743		10/31/2016	X
	Iroquois	RTS to Wright	470-01	4,047		$6.5971		10/31/2011	
	TGP	NET-NE	33371	4,000		$10.6100		10/31/2011	
	BP Canada Energy Co.**	Supply at Niagara		3,199		$0.0000		3/31/2012	X
	TGP	FT-A (Z5-Z6)	2302	3,122		$4.9300		10/31/2010	
	TGP	FT-A (Z0-Z6)	8587	7,035		$16.5900		10/31/2010	
	TGP	FT-A (Z1-Z6)	8587	14,561		$15.1500		10/31/2010	
	TGP	FT-A (Z6-Z6)	42076	20,000		$3.1600		10/31/2010	
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	$1.1500	$0.0185	10/31/2010	
	TGP	FT-A (Z4-Z6)	632	15,265		$5.8900		10/31/2010	
	TGP	FT-A (Z4-Z6)	8587	3,811		$5.8900		10/31/2010	
	National Fuel	FSS-1 (Storage)	O02357***	6,098	670,800	$2.1556	$0.0432	3/31/2008	
	National Fuel	FST (Transport)	N02358	6,098		$3.3612		3/31/2008	
	TGP	FT-A (Z4-Z6)	11234	6,150		$5.8900		10/31/2010	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	$4.4683	$0.0000	4/1/2008	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$4.9300		10/31/2010	
	Dominion	GSS (Storage)	300076***	934	102,700	$1.8780	$0.0145	3/31/2011	
	TGP	FT-A (Z4-Z6)	11234	932		$5.8900		10/31/2010	
Peaking									
	Energy North	LNG/Propane****		67,267	-	$9.7200	$0.0000		X

* Volumes and Demand Charges are based on MMBtu at the border.
**BP commodity price is based on Inside FERC at Niagara plus $.01 per Dth.
***All gas transferred for storage contracts will be based on LDC's monthly WACOG.
****All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months.

Note: **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/08. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the Energy North Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $27.4017/dth.

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ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

			Volume	Rate	Monthly Cost	Months/Year	Annual Cost
1	Granite Ridge - 30 days @ 15,000/dt						
2							
3							
4	DOMAC	FLS 164					
5	DOMAC	FLS 160					
6	Transgas	Trucking					*
7	Subtotal						**$1,579,133.36**
8							
9	**Total**						**$1,819,133.36**

* Contract currently being negotiated for an effective date of November 1, 2008.

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ATTACHMENT F

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	33.0%	20.0%	47.0%	100.0%
G-51	Low Annual /Low Winter Use	46.0%	16.0%	38.0%	100.0%
G-42	Medium Annual / High Winter	33.0%	20.0%	47.0%	100.0%
G-52	High Annual / Low Winter Use	46.0%	16.0%	38.0%	100.0%
G-43	High Annual / High Winter	33.0%	20.0%	47.0%	100.0%
G-53	High Annual / Load Factor < 90%	46.0%	16.0%	38.0%	100.0%
G-54	High Annual / Load Factor < 110%	46.0%	16.0%	38.0%	100.0%
G-63	High Annual / Load Factor > 110%	46.0%	16.0%	38.0%	100.0%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	**Storage**	**Peaking**	**Total**
G-41	**LAHW**	Low Annual C&I - High Winter Use	33.0%	20.0%	47.0%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	46.0%	16.0%	38.0%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	33.0%	20.0%	47.0%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	46.0%	16.0%	38.0%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	33.0%	20.0%	47.0%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	46.0%	16.0%	38.0%	100.0%
G-54	**HALW110**	High Annual C&I - LF < 110%	46.0%	16.0%	38.0%	100.0%
G-63	**HALWG110**	High Annual C&I - LF >110%	46.0%	16.0%	38.0%	100.0%

HLF	High Load Factor	46%	16%	38%	100%
LLF	Low Load Factor	33%	20%	47%	100%
	Total	35%	19%	46%	100%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD			80	
		Base load	Heat load	Total
HLF	R-1 RNSH	182	589	771
LLF	R-3 RSH	3,933	64,643	68,576
LLF	G-41 SL	786	24,044	24,830
HLF	G-51 SH	624	2,255	2,880
LLF	G-42 ML	1,807	34,276	36,083
HLF	G-52 MH	1,187	3,254	4,441
LLF	G-43 LL	446	3,218	3,663
HLF	G-53 LLL90	255	1,361	1,616
HLF	G-54 LLL110	425	68	493
HLF	G-63 LLG110	51	1,696	1,748
	TOTAL	9,696	135,404	145,100

HLF	2,725	9,223	11,948
LLF	6,971	126,181	133,152
Total	9,696	135,404	145,100

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	182	174	356	122	293	771
R-3 RSH	3,933	19,107	23,040	13,422	32,114	68,576
G-41 SL	786	7,107	7,893	4,992	11,945	24,830
G-51 SH	624	667	1,291	468	1,120	2,880
G-42 ML	1,807	10,131	11,938	7,117	17,028	36,083
G-52 MH	1,187	962	2,148	676	1,617	4,441
G-43 LL	446	951	1,397	668	1,598	3,663
G-53 LLL90	255	402	658	283	676	1,616
G-54 LLL110	425	20	445	14	34	493
G-63 LLG110	51	501	553	352	843	1,748
TOTAL	9,696	40,022	49,718	28,115	67,267	145,100

HLF	2,725	2,726	5,451	1,915	4,582	11,948
LLF	6,971	37,296	44,267	26,200	62,685	133,152
Total	9,696	40,022	49,718	28,115	67,267	145,100

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	46.2%	15.9%	37.9%	100.0%
R-3 RSH	33.6%	19.6%	46.8%	100.0%
G-41 SL	31.8%	20.1%	48.1%	100.0%
G-51 SH	44.8%	16.3%	38.9%	100.0%
G-42 ML	33.1%	19.7%	47.2%	100.0%
G-52 MH	48.4%	15.2%	36.4%	100.0%
G-43 LL	38.1%	18.2%	43.6%	100.0%
G-53 LLL90	40.7%	17.5%	41.8%	100.0%
G-54 LLL110	90.3%	2.9%	6.8%	100.0%
G-63 LLG110	31.6%	20.2%	48.2%	100.0%
TOTAL	34.3%	19.4%	46.4%	100.0%

High Load Factor	46%	16%	38%	100%
Low Load Factor	33%	20%	47%	100%
Total	35%	19%	46%	100%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU) | **Allocate Design Day Sendout to Rate Classes**

Design DD **80**

	Daily Baseload * 1000	February Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	182	6.534	523	705	26%	0.435%	182	589	771
R-3 RSH	3,933	717.273	57,382	61,315	6%	47.741%	3,933	64,643	68,576
G-41 SL	786	266.783	21,343	22,129	4%	17.757%	786	24,044	24,830
G-51 SH	624	25.026	2,002	2,626	24%	1.666%	624	2,255	2,880
G-42 ML	1,807	380.322	30,426	32,233	6%	25.314%	1,807	34,276	36,083
G-52 MH	1,187	36.107	2,889	4,075	29%	2.403%	1,187	3,254	4,441
G-43 LL	446	35.702	2,856	3,302	13%	2.376%	446	3,218	3,663
G-53 LLL90	255	15.098	1,208	1,463	17%	1.005%	255	1,361	1,616
G-54 LLL110	425	0.752	60	485	88%	0.050%	425	68	493
G-63 LLG110	51	18.822	1,506	1,557	3%	1.253%	51	1,696	1,748
TOTAL	9,696	1,502.419	120,194	129,890		100.000%	9,696	135,404	145,100

HLF	2,725	102	8,187	10,912
LLF	6,971	1,400	112,006	118,978
Total	9,696	1,502	120,194	129,890

Design Day from 2008-2009 Resource Plan		**145,100**
Design Day from Billing Calculation		129,890
Variance		15,210

7.275	6.534	0.74
789.745	717.273	72.47
292.165	266.783	25.38
29.339	25.026	4.31
385.503	380.322	5.18
36.876	36.107	0.77
41.787	35.702	6.08
8.367	15.098	(6.73)
0.928	0.752	0.18
-	11.884	(11.88)
1,591.984	1,495.481	

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-07	Sep-07	Oct-07	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	8	12	13	13	12	11	9	7	6	5	5	6	107	5.647	0.182
LLF	R-3 RSH	371	869	950	954	856	645	338	178	129	115	124	149	5,678	121.920	3.933
LLF	G-41 SL	101	282	341	336	312	211	90	41	25	23	26	34	1,821	24.367	0.786
HLF	G-51 SH	27	41	47	47	44	37	28	24	19	20	20	20	375	19.353	0.624
LLF	G-42 ML	188	428	509	498	464	340	172	97	59	53	60	75	2,944	56.012	1.807
HLF	G-52 MH	45	65	74	76	70	61	49	45	38	35	37	36	633	36.783	1.187
LLF	G-43 LL	18	28	59	54	53	59	47	35	19	9	8	17	406	13.815	0.446
HLF	G-53 LLL90	0	(0)	11	25	13	24	12	35	10	6	9	(4)	140	7.916	0.255
HLF	G-54 LLL110	3	2	(4)	13	6	7	(1)	13	(2)	2	2	2	42	12.745	0.425
HLF	G-63 LLG110	(7)	(8)	23	24	(31)	(9)	22	(7)	10	(7)	10	9	28	1.596	0.051
	TOTAL	754	1,720	2,024	2,039	1,800	1,385	766	468	313	261	301	343	12,174	287.368	9.270
	HLF	75	112	165	197	115	130	119	117	82	61	83	69	1,325	84.041	2.299
	LLF	679	1,607	1,859	1,842	1,685	1,254	647	352	232	200	218	274	10,850	216.115	6.971

Baseload (= the lesser of actual volumes or the average of July and August volumes)

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-07	Sep-07	Oct-07	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	5	6	6	5	6	5	6	5	6	5	5	6	66
LLF	R-3 RSH	118	122	122	110	122	118	122	118	129	115	118	122	1,436
LLF	G-41 SL	24	24	24	22	24	24	24	24	25	23	24	24	287
HLF	G-51 SH	19	19	19	17	19	19	19	19	19	20	19	19	228
LLF	G-42 ML	54	56	56	51	56	54	56	54	59	53	54	56	659
HLF	G-52 MH	36	37	37	33	37	36	37	36	38	35	36	36	433
LLF	G-43 LL	13	14	14	12	14	13	14	13	19	9	8	14	163
HLF	G-53 LLL90	0	(0)	8	7	8	8	8	8	10	6	8	(4)	93
HLF	G-54 LLL110	3	2	(4)	12	6	7	(1)	13	(2)	2	2	2	42
HLF	G-63 LLG110	(7)	(8)	2	1	(31)	(9)	2	(7)	10	(7)	2	2	19
	TOTAL	264	272	284	271	261	274	286	282	313	261	274	277	3,384
	HLF	55	55	67	76	45	65	70	73	82	61	70	61	881
	LLF	209	216	216	195	216	209	216	209	232	200	204	216	2,545

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Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
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Heating Volumes (= Actual Volumes - Baseload)

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-07	Sep-07	Oct-07	Total
HLF	R-1 RNSH	3	7	7	8	6	5	3	2	0	0	0	0	41
LLF	R-3 RSH	253	747	828	844	734	527	216	60	0	0	6	27	4,242
LLF	G-41 SL	77	257	317	314	288	187	65	17	0	0	3	9	1,534
HLF	G-51 SH	8	22	28	29	25	18	9	5	0	0	1	1	147
LLF	G-42 ML	134	372	453	447	408	286	116	43	0	0	6	19	2,285
HLF	G-52 MH	10	28	37	42	33	26	13	9	0	0	2	0	200
LLF	G-43 LL	5	15	45	42	39	45	33	22	0	0	0	3	244
HLF	G-53 LLL90	0	0	3	18	5	16	4	28	0	0	1	0	47
HLF	G-54 LLL110	0	0	0	1	0	0	0	0	0	0	0	0	0
HLF	G-63 LLG110	0	0	22	22	0	0	20	0	0	0	9	7	9
	TOTAL	490	1,448	1,741	1,768	1,539	1,110	480	186	0	0	27	66	8,791

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-07	Sep-07	Oct-07	Total
HLF	20	57	98	120	70	65	49	43	0	0	13	8	443
LLF	470	1,391	1,643	1,647	1,469	1,045	431	142	0	0	14	58	8,305
Actual BDD	588.0	1061.5	1240.5	1176.5	1082.0	778.5	405.5	161.0	21.5	16.0	70.5	217.5	6819.0

Heat Factors

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-07	Sep-07	Oct-07	Total
HLF	R-1 RNSH	0.0043	0.0063	0.0060	0.0065	0.0059	0.0068	0.0075	0.0094	0.0000	0.0000	0.0000	0.0004	
LLF	R-3 RSH	0.4308	0.7040	0.6678	0.7173	0.6787	0.6768	0.5320	0.3712	0.0000	0.0000	0.0860	0.1227	
LLF	G-41 SL	0.1311	0.2423	0.2554	0.2668	0.2657	0.2402	0.1608	0.1081	0.0000	0.0000	0.0402	0.0423	
HLF	G-51 SH	0.0139	0.0208	0.0223	0.0250	0.0230	0.0234	0.0223	0.0313	0.0000	0.0000	0.0155	0.0052	
LLF	G-42 ML	0.2282	0.3504	0.3650	0.3803	0.3772	0.3674	0.2872	0.2687	0.0000	0.0000	0.0792	0.0876	
HLF	G-52 MH	0.0164	0.0265	0.0302	0.0361	0.0309	0.0331	0.0311	0.0582	0.0000	0.0000	0.0238	0.0000	
LLF	G-43 LL	0.0085	0.0138	0.0363	0.0357	0.0361	0.0582	0.0823	0.1362	0.0000	0.0000	0.0000	0.0127	
HLF	G-53 LLL90	0.0000	0.0000	0.0027	0.0151	0.0046	0.0204	0.0092	0.1710	0.0000	0.0000	0.0170	0.0000	
HLF	G-54 LLL110	0.0000	0.0000	0.0000	0.0008	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
HLF	G-63 LLG110	0.0000	0.0000	0.0175	0.0188	0.0000	0.0000	0.0503	0.0000	0.0000	0.0000	0.1247	0.0325	
	TOTAL	0.8333	1.3642	1.4032	1.5024	1.4221	1.4264	1.1828	1.1542	0.0000	0.0000	0.3865	0.3033	

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	588.0	1061.5	1240.5	1176.5	1082.0	778.5	405.5	161.0	21.5	16.0	70.5	217.5	6819.0
Norm Billing DD	645.7	975.4	1243.2	1235.9	1066.6	790.6	446.8	184.8	44.2	20.6	96.8	336.4	7086.8

Normal Volumes (= Heating Volumes * Normal EDD/Actual EDD + Baseload)

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-07	Sep-07	Oct-07	Total
HLF	**R-1 RNSH**	8	12	13	13	12	11	9	7	6	5	5	6	108
LLF	**R-3 RSH**	396	809	952	997	846	653	360	187	129	115	126	163	5,732
LLF	**G-41 SL**	108	261	342	352	308	213	96	44	25	23	27	39	1,838
HLF	**G-51 SH**	28	40	47	48	44	37	29	25	19	20	20	21	378
LLF	**G-42 ML**	202	398	510	521	458	345	184	104	59	53	62	85	2,980
HLF	**G-52 MH**	46	63	74	78	70	62	51	46	38	35	38	36	637
LLF	**G-43 LL**	19	27	59	57	52	59	51	39	19	9	8	18	416
HLF	**G-53 LLL90**	0	(0)	11	26	13	24	12	39	10	6	9	(4)	146
HLF	**G-54 LLL110**	3	2	(4)	13	6	7	(1)	13	(2)	2	2	2	42
HLF	**G-63 LLG110**	(7)	(8)	23	25	(31)	(9)	24	(7)	10	(7)	14	13	38
	TOTAL	802	1,602	2,028	2,128	1,778	1,402	815	495	313	261	312	379	12,316

HLF	77	108	165	203	114	131	124	123	82	61	88	74	1,349
LLF	725	1,494	1,863	1,926	1,664	1,271	691	373	232	200	224	305	10,967

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6%				$0.3927	$0.3722	$ 943.37	$ 926.93	$ 16.44	1.77%	$0.3927	$0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9%				$0.4724	$0.4628	$ 679.85	$ 672.22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10.90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10.22%
4	Nov 01 - Apr 02	24%				$0.5141	$0.4818	$ 790.65	$ 760.55	$ 30.10	3.96%	$0.5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3.52%
5	Nov 02 - Apr 03	24%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2.27%	$0.5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3.25%	$0.8759	$0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3.34%
7	Nov 04 - Apr 05	30%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189.55	$ (46.60)	-3.92%	$0.9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3.51%
8	Nov 05 - Apr 06	30%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10.90%	$1.3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	15%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415.80	$ 93.99	6.64%	$1.2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	16%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$1,433.09	$1,405.40	$ 27.69	1.97%	$1.2044	$1.1725	$ 2,232.39	$2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09 1/					$1.2835	$1.2635	$1,555.78	$1,537.14	$ 18.64	1.21%	$1.2836	$1.2636	$2,406.91	$2,378.37	$ 28.54	1.20%
12																	
13	Total									$ 214.02						$ 321.34	

1/ The total bill calculation reflects the increase in base distribution rates as approved in Order No. 24,888 in DG 08-009.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2008 - 2009 Winter Cost of Gas Filing
Short Term Debt Limitations

	For Purposes of Fuel Financing
Total Direct Gas Costs	$ 111,027,254
Total Indirect Gas Costs	3,163,335
Total Gas Costs	$ 114,190,590
% of Debt to Total Gas Costs	30%
Short Term Debt	$ 34,257,177

	For Purposes Other Than Fuel Financing
12/1/09 Projected Net Plant	$ 238,900,000
% of Debt to Net Plant	20%
Short Term Debt	$ 47,780,000