ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing

Table of Contents

1	**ENERGY NORTH NATURAL GAS, INC.**			
2	**d/b/a National Grid NH**			
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 11-12
6		Reference		Nov - Apr
7	(a)	(b)		(c)
8				
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (j), ln 43	$	11,669,833
12	Supply Costs	Sch. 6, col (i), ln 44		35,469,665
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (j), ln 58	$	1,247,501
16	Commodity Costs:	Sch. 6, col (i), ln 47		8,822,497
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	381,653
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	2,091,917
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 163	$	-
22				
23	**Total Unadjusted Cost of Gas**		$	59,683,067
24				
25	**Adjustments:**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	3,735,297
28	Interest 10/31/11 - 04//30/12	Sch. 3, col (q) ln 194		123,025
29	Prior Period Adjustments	Sch. 4, ln 26 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(1,417,572)
32	Fuel Financing	Sch. 4, ln 26 col (e)		182,975
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		-
34	Interruptible Sales Margin	Sch. 4, ln 26 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)		(471,144)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
37	FPO Premium - Collection			
38	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		40,691
39				
40	**Total Adjustments**		$	2,193,271
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	61,876,339
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Anticipated Direct Cost of Gas	Ln 23	$	59,683,067
47	Lead Lag Days			0.0391
48	Prime Rate			3.25%
49	Working Capital Percentage	per GTC 16(f)		0.127%
50	Working Capital	ln 46 * ln 49		75,850
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 78		8,916
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	84,766
54				
55	**Bad Debt**			
56	Total Anticipated Direct Cost of Gas	ln 46	$	59,683,067
57	Less Refunds	ln 30		-
58	Plus Working Capital	ln 53		84,766
59	Plus Prior Period (Over) Under Recovery	ln 27		3,735,297
60	Subtotal		$	63,503,130
61	Bad Debt Percentage	per GTC 16(f)		2.37%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	1,505,024
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 163		36,020
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	1,541,044
67				
68	**Production and Storage Capacity**	per GTC16(f)	$	1,980,428
69				
70	**Miscellaneous Overhead**	per GTC 16(f)	$	13,170
71	Sales Volume	Sch. 10B, ln 23/1000		82,647
72	Divided by Total Sales	Sch. 10B, ln 23/1000		105,301
73	Ratio			78.49%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	10,337
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	3,616,575
78				
79	**Total Cost of Gas**	lns 42 + 77	$	65,492,914
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		82,632,661

Ln											
1	**ENERGY NORTH NATURAL GAS, INC.**										
2	**d/b/a National Grid NH**										
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 10 - Oct 10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10											
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	3,232,641	11,679,687	16,903,823	18,386,585	16,531,042	12,680,913	3,217,970	82,632,661
13	Lost Gas (Unaccounted for)		-	218,910	320,385	358,033	323,006	270,100	162,197		1,652,632
14	Company Use		-	129,692	189,811	212,115	191,364	160,020	96,093		979,095
15	Unbilled Therms		-	7,714,960	4,342,621	1,001,213	(2,233,196)	(3,023,460)	(4,569,498)	(3,217,970)	14,672
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	11,296,205	16,532,504	18,475,184	16,667,759	13,937,702	8,369,706		85,279,059
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	907,335	998,310	998,310	933,903	998,310	-		4,836,170
22	Niagara Supply	Sch. 6, ln 64	-	754,368	779,326	779,326	728,606	779,326	594,961		4,415,913
23	TGP Supply (Direct)	Sch. 6, ln 65	-	5,929,481	5,390,071	5,390,071	5,042,273	5,390,071	6,976,097		34,118,064
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	2,495,776	2,495,776	2,334,758	-	-		7,326,310
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	4,247,650	754,368	1,524,034	2,135,096	6,431,051	2,569,844		17,662,044
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	-	22,542	23,348	689,961	22,542	46,695	-		805,089
28	Propane Truck	Sch. 6, ln 70	-	-	-	-	-	-	-		-
29	PNGTS	Sch. 6, ln 71	-	64,407	82,119	89,365	80,509	73,263	53,136		442,799
30	Granite Ridge	Sch. 6, ln 72	-	-	-	-	-	-	-		-
31	Subtotal Pipeline Volumes		-	11,925,784	10,523,319	11,966,844	11,277,688	13,718,718	10,194,038		69,606,390
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	83,729	6,009,185	6,456,009	5,390,071	242,332	-		18,181,326
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	22,542	23,348	742,292	22,542	23,348	22,542		856,615
38	Propane	Sch. 6, ln 81	-	-	-	-	-	-	-		-
39	Subtotal Produced Gas		-	22,542	23,348	742,292	22,542	23,348	22,542		856,615
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(22,542)	(23,348)	(689,961)	(22,542)	(46,695)	-		(805,089)
43	Propane	Sch. 6, ln 87	-	-	-	-	-	-	-		-
44	TGP Storage Refill	Sch. 6, ln 88	-	(713,309)	-	-	-	-	(1,846,874)		(2,560,183)
45	Subtotal Refills		-	(735,851)	(23,348)	(689,961)	(22,542)	(46,695)	(1,846,874)		(3,365,272)
46											
47	Total Firm Sendout Volumes	lns 31 + 34 + 39 + 45	-	11,296,205	16,532,504	18,475,184	16,667,759	13,937,702	8,369,706		85,279,059
48											

Line	Description	Reference	Peak Costs May 10 - Oct 10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Peak Period Nov - Apr
1	**ENERGY NORTH NATURAL GAS, INC.**										
2	**d/b/a National Grid NH**										
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 10 - Oct 10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Nov - Apr
49	**II. Gas Costs**										
50											**REDACTED**
51	**A. Demand Costs**										
52	Supply										
53	Niagra Supply	Sch.5A, ln 12	[redacted]								
54	Subtotal Supply Demand										
55	Less Capacity Credit										
56	Net Pipeline Demand Costs										
57											
58	Pipeline:										
59	Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]								
60	Tenn Gas Pipeline 33371 Z5-Z6	Sch.5A, ln 17									
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18									
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19									
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20									
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21									
65	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22									
66	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 23									
67	Portland Natural Gas Trans Service	Sch.5A, ln 24									
68	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 25									
69	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 26									
70	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 27									
71	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 28									
72	National Fuel FST 2358	Sch.5A, ln 29									
73	Subtotal Pipeline Demand		$ 1,729,457	$ 1,421,521	$ 1,421,521	$ 1,421,521	$ 1,421,521	$ 1,421,521	$ 1,421,521		$ 10,258,586
74	Less Capacity Credit		(369,482)	(277,070)	(277,070)	(277,070)	(277,070)	(277,070)	(277,070)		(2,031,903)
75	Net Pipeline Demand Costs		$ 1,359,975	$ 1,144,451	$ 1,144,451	$ 1,144,451	$ 1,144,451	$ 1,144,451	$ 1,144,451		$ 8,226,683
76											
77	Peaking Supply:										
78	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 34	[redacted]								
79	Granite Ridge Demand	Sch.5A, ln 35									
80	DOMAC Demand FLS-160	Sch.5A, ln 36									
81	Subtotal Peaking Demand		$ 2,023,704	$ 337,284	$ 404,784	$ 404,784	$ 404,784	$ 404,784	$ 337,284		$ 4,317,407
82	Less Capacity Credit		(432,345)	(65,740)	(78,897)	(78,897)	(78,897)	(78,897)	(65,740)		(879,413)
83	Net Peaking Supply Demand Costs		$ 1,591,358	$ 271,544	$ 325,887	$ 325,887	$ 325,887	$ 325,887	$ 271,544		$ 3,437,994
84											
85	Storage:										
86	Dominion - Demand	Sch.5A, ln 46	[redacted]								
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		$ 771,454	$ 132,669	$ 132,669	$ 132,669	$ 132,669	$ 132,669	$ 132,669		$ 1,567,467
94	Less Capacity Credit		(164,814)	(25,859)	(25,859)	(25,859)	(25,859)	(25,859)	(25,859)		(319,965)
95	Net Storage Demand Costs		$ 606,640	$ 106,810	$ 106,810	$ 106,810	$ 106,810	$ 106,810	$ 106,810		$ 1,247,501
96											
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 4,524,614	$ 1,892,530	$ 1,960,065	$ 1,960,065	$ 1,959,995	$ 1,960,065	$ 1,892,530		$ 16,149,864
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(966,641)	(368,875)	(382,038)	(382,038)	(382,024)	(382,038)	(368,875)		(3,232,529)
99	Net Demand Charges		$ 3,557,973	$ 1,523,655	$ 1,578,027	$ 1,578,027	$ 1,577,970	$ 1,578,027	$ 1,523,655		$ 12,917,335
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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Line			Peak Costs May 10 - Oct 10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Peak Period Nov - Apr
5											
6											
7	For Month of:										
102	**B. Commodity Costs**										**REDACTED**
103	Pipeline:										
104	Dawn Supply	Sch. 6, ln 12	[redacted]								
105	Niagara Supply	Sch. 6, ln 13									
106	TGP Supply (Direct)	Sch. 6, ln 14									
107	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
108	Dracut Supply 2 - Swing	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		$ -	$ 5,379,492	$ 5,429,171	$ 6,998,934	$ 6,528,650	$ 6,866,333	$ 4,587,161		$ 35,789,742
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 40,630	$ 2,915,960	$ 3,132,782	$ 2,615,535	$ 117,592	$ -		$ 8,822,497
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50	[redacted]								
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 9,720	$ 10,101	$ 331,289	$ 10,077	$ 10,413	$ 10,054		$ 381,653
123											
124	Less Storage Refills:										
125	LNG Truck	Sch. 6, ln 37	[redacted]								
126	Propane	Sch. 6, ln 38									
127	TGP Storage Refill	Sch. 6, ln 39									
128	Storage Refill (Trans.)	Sch. 6, ln 40									
129	Subtotal Storage Refill		$ -	$ (323,317)	$ (10,230)	$ (309,144)	$ (10,104)	$ (20,788)	$ (869,171)		$ (1,542,755)
130											
131	Total Supply Commodity Costs		$ -	$ 5,106,525	$ 8,345,002	$ 10,153,860	$ 9,144,158	$ 6,973,550	$ 3,728,044		$ 43,451,138
132											
133	**C. Supply Volumetric Transportation Costs:**										
134	Dawn Supply	Sch. 6, ln 26	[redacted]								
135	Niagara Supply	Sch. 6, ln 27									
136	TGP Supply (Direct)	Sch. 6, ln 28									
137	Dracut Supply 1 - Baseload	Sch. 6, ln 29									
138	Dracut Supply 2 - Swing	Sch. 6, ln 30									
139	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 168,275	$ 161,714	$ 168,358	$ 158,525	$ 168,200	$ 216,454		$ 1,041,525
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 834	$ 59,873	$ 64,325	$ 53,705	$ 2,415	$ -		$ 181,152
142											
143	Total Supply Volumetric Trans. Costs	lns 139 + 141	$ -	$ 169,109	$ 221,587	$ 232,683	$ 212,230	$ 170,614	$ 216,454		$ 1,222,677
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 5,275,633	$ 8,566,589	$ 10,386,543	$ 9,356,388	$ 7,144,164	$ 3,944,498		$ 44,673,815
146											
147											

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

5											
6			Peak Costs								Peak Period
7	For Month of:		May 10 - Oct 10	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Nov - Apr
148	**D. Supply and Demand Costs by Source**										**REDACTED**
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	Ins 54 + 73	$ 1,729,457	$ 1,422,577	$ 1,422,612	$ 1,422,612	$ 1,422,542	$ 1,422,612	$ 1,422,577		$ 10,264,990
152	Peaking Gas Demand Costs	In 81	2,023,704	337,284	404,784	404,784	404,784	404,784	337,284		4,317,407
153	Subtotal Purchased Gas Demand Costs		$ 3,753,160	$ 1,759,861	$ 1,827,396	$ 1,827,396	$ 1,827,326	$ 1,827,396	$ 1,759,861		$ 14,582,397
154	Less Capacity Credit	Ins 55 + 74 + 82	(801,827)	(343,016)	(356,180)	(356,180)	(356,166)	(356,180)	(343,016)		(2,912,564)
155	Net Purchased Gas Demand Costs		$ 2,951,333	$ 1,416,845	$ 1,471,217	$ 1,471,217	$ 1,471,160	$ 1,471,217	$ 1,416,845		$ 11,669,833
156											
157	Storage Gas Demand Costs										
158	Storage Demand	In 93	$ 771,454	$ 132,669	$ 132,669	$ 132,669	$ 132,669	$ 132,669	$ 132,669		$ 1,567,467
159	Less Capacity Credit	In 94	(164,814)	(25,859)	(25,859)	(25,859)	(25,859)	(25,859)	(25,859)		(319,965)
160	Net Storage Demand Costs		$ 606,640	$ 106,810	$ 106,810	$ 106,810	$ 106,810	$ 106,810	$ 106,810		$ 1,247,501
161											
162	**Total Demand Costs**	Ins 155 + 160	$ 3,557,973	$ 1,523,655	$ 1,578,027	$ 1,578,027	$ 1,577,970	$ 1,578,027	$ 1,523,655		$ 12,917,335
163											
164	Purchased Gas Supply										
165	Commodity Costs	In 114	$ -	$ 5,379,492	$ 5,429,171	$ 6,998,934	$ 6,528,650	$ 6,866,333	$ 4,587,161		$ 35,789,742
166	Less Storage Inj.(TGP Storage)	In 127	[redacted]								
167	Less Storage Transportation	In 128									
168	Less LNG Truck	In 125									
169	Less Propane Truck	In 126									
170	Plus Transportation Costs	In 139									
171	Subtotal Purchased Gas Supply		$ -	$ 5,224,450	$ 5,580,654	$ 6,858,148	$ 6,677,071	$ 7,013,745	$ 3,934,444		$ 35,288,513
172											
173	Storage Commodity Costs										
174	Commodity Costs	In 117	$ -	$ 40,630	$ 2,915,960	$ 3,132,782	$ 2,615,535	$ 117,592	$ -		$ 8,822,497
175	Transportation Costs	In 141	-	834	59,873	64,325	53,705	2,415	-		181,152
176	Subtotal Storage Commodity Costs		$ -	$ 41,464	$ 2,975,833	$ 3,197,107	$ 2,669,239	$ 120,006	$ -		$ 9,003,650
177											
178	Produced Gas Commodity Costs	In 122	$ -	$ 9,720	$ 10,101	$ 331,289	$ 10,077	$ 10,413	$ 10,054		$ 381,653
179											
180	**SubTotal Commodity Costs**	Ins 171 + 176 + 178	$ -	$ 5,275,633	$ 8,566,589	$ 10,386,543	$ 9,356,388	$ 7,144,164	$ 3,944,498		$ 44,673,815
181											
182	Hedge Contract (Savings)/Loss	Sch 7, In 32	$ -	$ 328,034	$ 423,822	$ 394,762	$ 343,022	$ 427,246	$ 175,031		$ 2,091,917
183											
184	**Total Commodity Costs**	Ins 180 + 182	$ -	$ 5,603,667	$ 8,990,411	$ 10,781,305	$ 9,699,410	$ 7,571,410	$ 4,119,529		$ 46,765,732
185											
186	**Total Demand Costs**	In 99	$ 3,557,973	$ 1,523,655	$ 1,578,027	$ 1,578,027	$ 1,577,970	$ 1,578,027	$ 1,523,655		$ 12,917,335
187	**Total Supply Costs**	In 184	-	5,603,667	8,990,411	10,781,305	9,699,410	7,571,410	4,119,529		46,765,732
188											
189	**Total Direct Gas Costs**	Ins 186 + 187	$ 3,557,973	$ 7,127,323	$ 10,568,438	$ 12,359,332	$ 11,277,380	$ 9,149,437	$ 5,643,184		$ 59,683,067
190											
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Line	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
1	**ENERGY NORTH NATURAL GAS, INC.**					**REDACTED**
2	**d/b/a National Grid NH**					
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**					
4	**Contracts Ranked on a per Unit Cost Basis**					**Peak Period**
5				**Contract**	**Unit Dth**	**Cost per**
6	**Supplier**	**Contract**	**Contract Type**	**Unit**	**(MDQ/ACQ)**	**Unit Dth**
7	(a)	(b)	(c)	(d)	(e)	(f)
8						
9	**Demand Costs**					
10	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	[redacted]
11	Tenn Gas Pipeline - Cap. Reservations	FS-MA	Storage	ACQ	1,560,391	
12	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
13	Niagra Supply		Supply	MDQ	3,199	
14	Granite Ridge Demand		Peaking	MDQ	15,000	
15	Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
18	National Fuel	FST 2358	Transportation	MDQ	6,098	
19	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
20	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
21	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
22	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
23	Tenn Gas Pipeline	33371 Z5-Z6	Transportation	MDQ	4,000	
24	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
25	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
26	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
27	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
28	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	72694 Z6-Z6	Transportation	MDQ	30,000	
29	ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
30	DOMAC Liquid Demand Charge	FLS-160	Peaking	MDQ	-	
31	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
32	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
33	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
34						
35	**Supply Costs - Commodity**					
36	City Gate Delivered Supply		Pipeline	Dkt	-	[redacted]
37	LNG Truck		Pipeline	Dkt	80,509	
38	TGP Supply (Direct)		Pipeline	Dkt	3,411,806	
39	LNG Vapor (Storage)		Produced	Dkt	85,661	
40	Dawn Supply		Pipeline	Dkt	483,617	
41	Niagara Supply		Pipeline	Dkt	441,591	
42	PNGTS		Pipeline	Dkt	44,280	
43	Granite Ridge		Pipeline	Dkt	-	
44	Dracut Supply 1 - Baseload		Pipeline	Dkt	732,631	
45	Dracut Supply 2 - Swing		Pipeline	Dkt	1,766,204	
46	TGP Storage		Storage	Dkt	1,818,133	
47	Propane		Produced	Dkt	-	
48	Propane Truck		Pipeline	Dkt	-	
49						
50	**Supply Costs - Volumetric Transportation**					
51	Dracut Supply 1 - Baseload		Pipeline	Dkt	732,631	[redacted]
52	Dracut Supply 2 - Swing		Pipeline	Dkt	1,766,204	
53	Niagara Supply		Pipeline	Dkt	441,591	
54	TGP Storage - Withdrawals		Pipeline	Dkt	1,818,133	
55	Dawn Supply		Pipeline	Dkt	483,617	
56	TGP Supply (Direct)		Pipeline	Dkt	3,411,806	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

5			Prior Period Balance														
6			Apr-11														
7			Ending Bal	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Peak Period
8		Days in Month	Plus May Billings	31	30	31	31	30	31	30	31	31	29	31	30	31	Total
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**																
12	**Beginning Balance**	Account 175.20 1/	**$ 4,200,751**	$ 3,735,297	$ 4,129,375	$ 4,078,279	$ 4,566,500	$ 5,112,125	$ 5,720,629	$ 6,108,737	$ 5,111,611	$ 3,599,799	$ 2,347,684	$ 1,386,837	$ 407,992	$ 111,513	$ 4,200,751
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		477,447	616,105	616,105	616,105	616,105	616,105	7,127,323	10,568,438	12,359,332	11,277,380	9,149,437	5,643,184	-	59,683,067
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	331,794	331,794	331,794	331,794	331,794	331,794		1,990,765
15	Projected Revenues w/o Int.	In 52 * 59		-	-	-	-	-	-	(2,493,660)	(9,009,710)	(13,039,609)	(14,183,412)	(12,752,046)	(9,782,056)	(2,482,342)	(63,742,834)
16	Projected Unbilled Revenue									(5,951,320)	(9,301,218)	(10,073,554)	(8,350,867)	(6,018,570)	(2,493,660)		(42,189,190)
17	Reverse Prior Month Unbilled										5,951,320	9,301,218	10,073,554	8,350,867	6,018,570	2,493,660	42,189,190
18	Prior Period Adjustment-Unbilled				-					-							-
19	Add Net Adjustments	Schedule 4		(94,850)	(678,149)	(139,798)	(83,820)	(22,050)	(244,301)	(26,229)	(64,441)	(139,494)	(114,112)	(42,802)	(15,004)	-	(1,665,050)
20	Gas Cost Billed	Account 175.20 2/	(465,455)	-	-	-	-	-	-	-	-	-	-	-	-	-	(465,455)
21	Monthly (Over)/Under Recovery		$ 3,735,297	$ 4,117,894	$ 4,067,331	$ 4,554,586	$ 5,098,785	$ 5,706,180	$ 6,092,433	$ 5,096,644	$ 3,587,793	$ 2,339,487	$ 1,382,022	$ 405,518	$ 110,820	$ 122,831	$ 1,244
22	Average Monthly Balance	(In 12 + 21)/2		$ 4,159,323	$ 4,098,353	$ 4,316,432	$ 4,832,643	$ 5,409,152	$ 5,906,531	$ 5,602,691	$ 4,349,702	$ 2,969,643	$ 1,864,853	$ 896,178	$ 259,406	$ 117,172	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
26	Interest Applied	In 22 * In 24 / 365 * Days of Month		$ 11,481	$ 10,948	$ 11,915	$ 13,339	$ 14,449	$ 16,304	$ 14,966	$ 12,006	$ 8,197	$ 4,815	$ 2,474	$ 693	$ -	$ 121,587
28	**(Over)/Under Balance**	In 21 + In 26	$ 3,735,297	$ 4,129,375	$ 4,078,279	$ 4,566,500	$ 5,112,125	$ 5,720,629	$ 6,108,737	$ 5,111,611	$ 3,599,799	$ 2,347,684	$ 1,386,837	$ 407,992	$ 111,513	$ 122,831	122,831
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	In 12	$ 4,200,751	$ 3,735,297	$ 4,129,375	$ 4,078,279	$ 4,566,500	$ 5,112,125	$ 5,720,629	$ 6,108,737	$ 5,095,187	$ 3,559,281	$ 2,280,170	$ 1,294,894	$ 295,508	$ (13,453)	$ 4,200,751
34	Fcst Direct Gas Costs(Inc U/G Hedges)	In 13		477,447	616,105	616,105	616,105	616,105	616,105	7,127,323	10,568,438	12,359,332	11,277,380	9,149,437	5,643,184	-	59,683,067
35	Prod Storage & Misc Overhead	In 14		-	-	-	-	-	-	331,794	331,794	331,794	331,794	331,794	331,794	-	1,990,765
36	Projected Revenues with int.	In 52 * In 61		-	-	-	-	-	-	(2,498,508)	(9,027,230)	(13,064,965)	(14,210,992)	(12,776,842)	(9,801,078)	(2,487,169)	(63,866,783)
37	Projected Unbilled Revenue									(5,962,893)	(9,319,305)	(10,093,143)	(8,367,105)	(6,030,273)	(2,498,508)		(42,271,227)
38	Reverse Prior Month Unbilled										5,962,893	9,319,305	10,093,143	8,367,105	6,030,273	2,498,508	42,271,227
39	Add Net Adjustments	In 19		(94,850)	(678,149)	(139,798)	(83,820)	(22,050)	(244,301)	(26,229)	(64,441)	(139,494)	(114,112)	(42,802)	(15,004)	-	(1,665,050)
40	Gas Cost Billed	In 20	(465,455)		-	-	-	-	-	-	-	-	-	-	-	-	(465,455)
41	Add Interest	In 26		-	-	-	-	-	-	14,966	12,006	8,197	4,815	2,474	693	-	43,152
42	**(Over)/Under Balance**		$ 3,735,297	$ 4,117,894	$ 4,067,331	$ 4,554,586	$ 5,098,785	$ 5,706,180	$ 6,092,433	$ 5,095,189	$ 3,559,342	$ 2,280,307	$ 1,295,093	$ 295,787	$ (13,137)	$ (2,113)	$ (79,553)
44	Average Monthly Balance			$ 4,159,323	$ 4,098,353	$ 4,316,432	$ 4,832,643	$ 5,409,152	$ 5,906,531	$ 5,601,963	$ 4,327,265	$ 2,919,794	$ 1,787,632	$ 795,340	$ 141,186	$ (7,783)	
46	Interest Applied	In 24 * In 44 / 365 * Days of Month		11,481	10,948	11,915	13,339	14,449	16,304	14,964	11,944	8,059	4,616	2,195	377	-	120,592
48	**(Over)/Under Balance**	-In 41 +In 42 + In 46	$ 3,735,297	$ 4,129,375	$ 4,078,279	$ 4,566,500	$ 5,112,125	$ 5,720,629	$ 6,108,737	$ 5,095,187	$ 3,559,281	$ 2,280,170	$ 1,294,894	$ 295,508	$ (13,453)	$ (2,113)	(2,113)
51	Forecast Sendout Therms	Sch 1								11,296,205	16,532,504	18,475,184	16,667,759	13,937,702	8,369,706		85,279,059
52	Less Forecast Billing Therm Sales	Sch. 10B, In 23 Nov - May								3,232,641	11,679,687	16,903,823	18,386,585	16,531,042	12,680,913	3,217,970	82,632,661
53	Less Forecast Unaccounted For	Sch 1								218,910	320,385	358,033	323,006	270,100	162,197		1,652,632
54	Less Forecast Company Use	Sch 1								129,692	189,811	212,115	191,364	160,020	96,093		979,095
55	Unbilled Volumes									7,714,960	4,342,621	1,001,213	-2,233,196	-3,023,460	-4,569,498	-3,217,970	14,672
56	Gross Unbilled									7,714,960	12,057,582	13,058,795	10,825,599	7,802,139	3,232,641	14,672	
59	COB w/o Interest	Sch. 3, pg. 4, In 211 col. (c)								$0.7714	$0.7714	$0.7714	$0.7714	$0.7714	$0.7714	$0.7714	
61	COG With Interest	Sch. 3, pg. 4, In 211 col. (d)								$0.7729	$0.7729	$0.7729	$0.7729	$0.7729	$0.7729	$0.7729	

65 1/ Beginning Balance for Acct 175.20. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
66 2/ Gas Cost Billed Acct 175.20. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line			Prior Period Balance Apr-11 Ending Bal Plus May Collections	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Peak Period Total
73		Days in Month		31	30	31	31	30	31	30	31	31	29	31	30	31	
74	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
75																	
76	**Accunt 142.20 Working Capital (Over)/Under Balance - Interest Calculation**																
77																	
78	**Beginning Balance**	Account 142.20 1/	$ 6,077	$ 8,916	$ 9,544	$ 10,354	$ 11,166	$ 11,981	$ 12,797	$ 13,617	$ 11,761	$ 9,199	$ 7,023	$ 5,218	$ 3,350	$ 2,418	$ 6,077
79																	
80	Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
81	Prime Rate			3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
82	Forecast Working Capital	ln 34 * 0.091%		607	783	783	783	783	783	9,058	13,431	15,707	14,332	11,628	7,172	-	75,850
83																	
84	Projected Revenues w/o Int.	ln 121 * ln 125		-	-	-	-	-	-	(3,233)	(11,680)	(16,904)	(18,387)	(16,531)	(12,681)	(3,218)	(82,633)
85	Projected Unbilled Revenue									(7,715)	(12,058)	(13,059)	(10,826)	(7,802)	(3,233)		(54,692)
86	Reverse Prior Month Unbilled										7,715	12,058	13,059	10,826	7,802	3,233	54,692
87																	
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
89																	
90	Working Capital Billed	Account 142.20 2/	2,839														2,839
91																	
92	Monthly (Over)/Under Recovery		$ 8,916	$ 9,523	$ 10,327	$ 11,137	$ 11,949	$ 12,764	$ 13,580	$ 11,727	$ 9,170	$ 7,001	$ 5,202	$ 3,338	$ 2,411	$ 2,433	$ 2,133
93																	
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ 7,800	$ 9,936	$ 10,745	$ 11,558	$ 12,373	$ 13,189	$ 12,672	$ 10,465	$ 8,100	$ 6,113	$ 4,278	$ 2,880	$ 2,426	
95																	
96	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
97																	
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ 22	$ 27	$ 30	$ 32	$ 33	$ 36	$ 34	$ 29	$ 22	$ 16	$ 12	$ 8	$ -	$ 299
99																	
100	**(Over)/Under Balance**	ln 92 + ln 98	$ 8,916	$ 9,544	$ 10,354	$ 11,166	$ 11,981	$ 12,797	$ 13,617	$ 11,761	$ 9,199	$ 7,023	$ 5,218	$ 3,350	$ 2,418	$ 2,433	2,433
101																	
102																	
103	**Calculation of Working Capital with Interest**																
104																	
105	**Beginning Balance**	ln 78	$ 6,077	$ 8,916	$ 9,544	$ 10,354	$ 11,166	$ 11,981	$ 12,797	$ 13,617	$ 11,761	$ 9,199	$ 7,024	$ 5,218	$ 3,350	$ 2,418	$ 6,077
106	Forecast Working Capital	ln 82		607	783	783	783	783	783	9,058	13,431	15,707	14,332	11,628	7,172	-	75,850
107	Projected Rev. with interest	ln 121 * ln 127		-	-	-	-	-	-	(3,233)	(11,680)	(16,904)	(18,387)	(16,531)	(12,681)	(3,218)	(82,633)
108	Projected Unbilled Revenue									(7,715)	(12,058)	(13,059)	(10,826)	(7,802)	(3,233)		(54,692)
109	Reverse Prior Month Unbilled										7,715	12,058	13,059	10,826	7,802	3,233	54,692
110	Add Net Adjustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	2,839	-	-	-	-	-	-								2,839
112	Add Interest	ln 98		-	-	-	-	-	-	34	29	22	16	12	8	-	120
113	Monthly (Over)/Under Recovery		$ 8,916	$ 9,523	$ 10,327	$ 11,137	$ 11,949	$ 12,764	$ 13,580	$ 11,761	$ 9,199	$ 7,024	$ 5,218	$ 3,350	$ 2,418	$ 2,433	$ 2,254
114																	
115	Average Monthly Balance			$ 7,800	$ 9,936	$ 10,745	$ 11,558	$ 12,373	$ 13,189	$ 12,689	$ 10,480	$ 8,111	$ 6,121	$ 4,284	$ 2,884	$ 2,426	
116																	
117	Interest Applied	ln 96 * ln 115 / 365 * Days of Month		22	27	30	32	33	36	34	29	22	16	12	8	-	$ 300
118																	
119	**(Over)/Under Balance**	-ln 112 +ln 113 + ln 117	$ 8,916	$ 9,544	$ 10,354	$ 11,166	$ 11,981	$ 12,797	$ 13,617	$ 11,761	$ 9,199	$ 7,024	$ 5,218	$ 3,350	$ 2,418	$ 2,433	$ 2,433
120																	
121	Forecast Therm Sales	ln 52								3,232,641	11,679,687	16,903,823	18,386,585	16,531,042	12,680,913	3,217,970	82,632,661
122	Unbilled Therm	ln 55								7,714,960	4,342,621	1,001,213	(2,233,196)	(3,023,460)	(4,569,498)		
123	Gross Unbilled									7,714,960	12,057,582	13,058,795	10,825,599	7,802,139	3,232,641		
124																	
125	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 228 col. (c)								$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	
126																	
127	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 228 col. (d)								$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	

128 1/ Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.
129 2/ Working Capital Billed Acct 142.20. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

130			Prior Period Balance														
131			Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	DemandPeriod
132		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	29	31	30	31	Total
133	(a)	(b)	Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
134																	
135	**Accunt 175.52 Bad Debt (Over)/Under Balance - Interest Calculation**																
136																	
137	Forecast Direct Gas Costs	In 34		$ 477,447	$ 616,105	$ 616,105	$ 616,105	$ 616,105	$ 616,105	$ 7,127,323	$ 10,568,438	$ 12,359,332	$ 11,277,380	$ 9,149,437	$ 5,643,184	$ -	59,683,067
138	Forecast Working Capital	In 106		607	783	783	783	783	783	17,974	13,431	15,707	14,332	11,628	7,172		84,766
139	Prior Period Balance	In 42								622,549	622,549	622,549	622,549	622,549	622,549		3,735,297
140	Total Forecast Direct Gas Costs & Working Capital			478,054	616,888	616,888	616,888	616,888	616,888	7,767,846	11,204,418	12,997,589	11,914,262	9,783,614	6,272,906	-	59,767,834
141																	
142	**Beginning Balance**	Account 175.52 1/	**$ 46,541**	$ 36,020	$ 47,480	$ 62,246	$ 77,059	$ 91,912	$ 106,797	$ 121,732	$ 102,504	$ 70,272	$ 45,440	$ 27,449	$ 8,129	$ 5,943	$ 46,541
143																	
144	Forecast Bad Debt	In 140 * 0.0237		11,330	14,620	14,620	14,620	14,620	14,620	184,098	265,545	308,043	282,368	231,872	148,668		1,505,024
145																	
146	Projected Revenues w/o int	In 183 * In 187		-	-	-	-	-	-	(60,127)	(217,242)	(314,411)	(341,990)	(307,477)	(235,865)	(59,854)	(1,536,967)
147	Projected Unbilled Revenue									(143,498)	(224,271)	(242,894)	(201,356)	(145,120)	(60,127)		(1,017,266)
148	Reverse Prior Month Unbilled										143,498	224,271	242,894	201,356	145,120	60,127	1,017,266
149																	
150	Bad Debt Billed	Account 175.52 2/	(10,521)		-	-	-	-	-		-	-	-	-	-	-	(10,521)
151																	
152	Add Net Adjustments		-	-	-	-	-	-	-		-	-	-	-	-	-	-
153																	
154	Monthly (Over)/Under Recovery		$ 36,020	$ 47,350	$ 62,100	$ 76,867	$ 91,679	$ 106,532	$ 121,417	$ 102,205	$ 70,034	$ 45,281	$ 27,355	$ 8,080	$ 5,925	$ 6,216	$ 4,077
155																	
156	Average Monthly Balance	(In 142 + In 154)/2		$ 46,946	$ 54,790	$ 69,556	$ 84,369	$ 99,222	$ 114,107	$ 111,969	$ 86,269	$ 57,776	$ 36,398	$ 17,765	$ 7,027	$ 6,080	
157																	
158	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
159																	
160	Interest Applied	In 156 * In 158 / 365 * Days of Month		$ 130	$ 146	$ 192	$ 233	$ 265	$ 315	$ 299	$ 238	$ 159	$ 94	$ 49	$ 19		$ 2,139
161																	
162	**(Over)/Under Balance**	In 154 + In 160	$ 36,020	$ 47,480	$ 62,246	$ 77,059	$ 91,912	$ 106,797	$ 121,732	$ 102,504	$ 70,272	$ 45,440	$ 27,449	$ 8,129	$ 5,943	$ 6,216	6,216
163																	
164																	
165	**Calculation of Bad Debt with Interest**																
166																	
167	**Beginning Balance**	In 142	$ 46,541	$ 36,020	$ 47,480	$ 62,246	$ 77,059	$ 91,912	$ 106,797	$ 121,732	$ 101,408	$ 67,569	$ 40,947	$ 21,341	$ 670	$ (2,327)	$ 46,541
168	Forecast Bad Debt	In 144		11,330	14,620	14,620	14,620	14,620	14,620	184,098	265,545	308,043	282,368	231,872	148,668	-	1,505,024
169	Projected Revenues with int.	In 183 * In 189		-	-	-	-	-	-	(60,450)	(218,410)	(316,101)	(343,829)	(309,130)	(237,133)	(60,176)	(1,545,231)
170	Projected Unbilled Revenue									(144,270)	(225,477)	(244,199)	(202,439)	(145,900)	(60,450)		(1,022,735)
171	Reverse Prior Month Unbilled										144,270	225,477	244,199	202,439	145,900	60,450	1,022,735
172	Bad Debt Billed	In 150	(10,521)		-	-	-	-	-	-	-	-	-	-	-	-	(10,521)
173	Add Interest	In 160		-	-	-	-	-	-	299	238	159	94	49	19	-	858
174	Add Net Adjustments	In 152	-							-	-	-	-	-	-	-	0
175	Monthly (Over)/Under Recovery		$ 36,020	$ 47,350	$ 62,100	$ 76,867	$ 91,679	$ 106,532	$ 121,417	$ 101,409	$ 67,574	$ 40,947	$ 21,341	$ 670	$ (2,327)	$ (2,053)	$ (3,328)
176																	
177	Average Monthly Balance			$ 46,946	$ 54,790	$ 69,556	$ 84,369	$ 99,222	$ 114,107	$ 111,571	$ 84,491	$ 54,258	$ 31,144	$ 11,005	$ (829)	$ (2,190)	
178																	
179	Interest Applied	In 158 * In 177 / 365 * Days of Month		130	146	192	233	265	315	298	233	159	94	49	19	-	$ 2,133
180																	
181	**(Over)/Under Balance**	-In 173 +In 175 + In 179	$ 36,020	$ 47,480	$ 62,246	$ 77,059	$ 91,912	$ 106,797	$ 121,732	$ 101,408	$ 67,569	$ 40,947	$ 21,341	$ 670	$ (2,327)	$ (2,053)	$ (2,053)
182																	
183	Forecast Term Sales	In 52								3,232,641	11,679,687	16,903,823	18,386,585	16,531,042	12,680,913	3,217,970	82,632,661
184	Unbilled Therm	In 55								7,714,960	4,342,621	1,001,213	(2,233,196)	(3,023,460)	(4,569,498)		
185	Gross Unbilled									7,714,960	12,057,582	13,058,795	10,825,599	7,802,139	3,232,641		
186																	
187	COG Rate Without Interest	Sch. 3, pg. 4, In 245 col. (c)								$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	
188																	
189	COG With Interest	Sch. 3, pg. 4, In 245 col. (d)								$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	

190 1/ Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.
191 2/ Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.
192

193	**Total Interest**	Ins 46 + 117 + 179	$ -	$ 11,632	$ 11,121	$ 12,136	$ 13,604	$ 14,747	$ 16,655	$ 15,296	$ 12,207	$ 8,241	$ 4,726	$ 2,256	$ 404	$ -	$ 123,025

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			COG Rate Without Interest	COG Rate With Interest
194				
195	**Calculation of COG**			
196	(a)	(b)	(c)	(d)
197	(Over)Under Recovery Balance	ln 12, col. (q)	$ 4,200,751	$ 4,200,751
198				
199	Unadjusted Forecast of Gas Costs	ln 13, col. (q)	59,683,067	59,683,067
200				
201	Production & Storage and Misc Overhea	ln 14, col. (q)	1,990,765	1,990,765
202				
203	Adjustments	ln 19, col. (q)	(2,130,505)	(2,130,505)
204				
205	Interest Nov -Apr	ln 46, col. (q)	-	$ 120,592
206				
207	Total Gas To Be Recovered		$ 63,744,078	$ 63,864,670
208				
209	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	82,632,661	82,632,661
210				
211	Preliminary COG Rate	ln. 207 / ln. 209	$0.7714	$0.7729
212				
213				

Ln			Working Capital Rate without interest	Working Capital Rate with Interest
214	**Calculation of Working Capital Rate**			
215	(a)	(b)	(c)	(d)
216	(Over)Under Recovery Balance	ln 78, col. (q)	$ 6,077	$ 6,077
217				
218	Unadjusted Working Capital Forecast	ln 82, col. (q)	75,850	75,850
219				
220	Adjustments without interest	ln 88, col. (q)	2,839	2,839
221				
222	Interest Nov -Apr	ln 117, col. (q)	-	$ 300
223				
224	Total Gas To Be Recovered		$ 84,766	$ 85,066
225				
226	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	82,632,661	82,632,661
227				
228	Preliminary Working Capital COG Rate		$0.0010	$0.0010
229				
230				

Ln			Bad Debt Rate without Interest	Bad Debt Rate with interest
231	**Calculation of Bad Debt Rate**			
232	(a)	(b)	(c)	
233	(Over)Under Recovery Balance	ln 142, col. (q)	$ 46,541	$ 46,541
234				
235	Unadjusted Bad Debt Forecast	ln 144, col. (q)	1,505,024	1,505,024
236				
237	Adjustments without interest	ln 152, col. (q)	(10,521)	(10,521)
238				
239	Interest Nov -Apr	ln 179, col. (q)	-	$ 2,133
240				
241	Total Gas To Be Recovered		$ 1,541,044	$ 1,543,178
242				
243	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	82,632,661	82,632,661
244				
245	Preliminary Bad Debt COG Rate		$0.0186	$0.0187

ENERGY NORTH NATURAL GAS, INC. **REDACTED**
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Adjustments to Gas Costs

Adjustments		Prior Period Adjustments	Refunds from Suppliers	Broker Revenue	Inventory Finance Charges	Transportation CGA Revenues (Schedule 17)	Interruptible Sales Margin	Off System Sales Margin	Capacity Release	PCB Refunds	Fixed Price Option Administrative Costs	Total Adjustments
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
May-11		$ -	$ -	$ (50,842)	$ 8,616	$ -	[redacted]			$ -	$ -	$ (94,850)
Jun-11		-	-	(606,249)	7,395	-	[redacted]			-	-	(678,149)
Jul-11		-	-	(64,173)	5,636	-	[redacted]			-	-	(139,798)
Aug-11	1/	-	-	(9,614)	21,174	-	[redacted]			-	-	(83,820)
Sep-11	1/	-	-	(29,921)	45,273	-	[redacted]			-	-	(22,050)
Oct-11	1/	-	-	(226,455)	(7,114)	-	[redacted]			-	-	(244,301)
Nov-11	1/	-	-	(69,450)	18,418	-	[redacted]			-	40,691	(26,229)
Dec-11	1/	-	-	(87,252)	24,795	-	[redacted]			-	-	(64,441)
Jan-12	1/	-	-	(69,039)	20,703	-	[redacted]			-	-	(139,494)
Feb-12	1/	-	-	(130,537)	18,700	-	[redacted]			-	-	(114,112)
Mar-12	1/	-	-	(47,165)	6,533	-	[redacted]			-	-	(42,802)
Apr-12	1/	-	-	(26,875)	12,846	-	[redacted]			-	-	(15,004)
Subtotal May 11 - Oct 11		$ -	$ -	$ (987,254)	$ 80,980	$ -	$ -	$ (44,872)	$ (311,822)	$ -	$ -	$ (1,262,968)
Subtotal Nov 11 - Apr 12		$ -	$ -	$ (430,318)	$ 101,995	$ -	$ -	$ (95,170)	$ (19,280)	$ -	$ 40,691	$ (402,082)
Total Peak Period		$ -	$ -	$ (1,417,572)	$ 182,975	$ -	$ -	$ (140,042)	$ (331,102)	$ -	$ 40,691	$ (1,665,050)

1/ Estimate is based on prior years actual. Exception: Transportation Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 10 - Apr 11 calculated on Schedule 16.

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1	**ENERGY NORTH NATURAL GAS, INC.**											
2	**d/b/a National Grid NH**											
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**											
4	**Demand Costs**											
5												
6												Peak
7				Peak Costs								May -Apr
8		Peak	Reference	May 11 -Oct 11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12		Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)		(k)
10												
11	**Supply**											
12	Niagra Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	[redacted]								
13	Subtotal Supply Demand & Reservation Charges											
14												
15	**Pipeline**											
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]								
17	Tenn Gas Pipeline 33371 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days									
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days									
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days									
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days									
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days									
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 24 x days									
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 26 x days									
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 28 x days									
25	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 21 * Sch 5C ln 44 x days									
26	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 22 * Sch 5C ln 30 x days									
27	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 23 * Sch 5C ln 32 x days									
28	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 24 * Sch 5C ln 34 x days									
29	National Fuel FST 2358	peak	Sch 5B, ln 25 * Sch 5C ln 36 x days									
30												
31	Subtotal Pipeline Demand Charges			$ 1,729,457	$ 1,421,521	$ 1,421,521	$ 1,421,521	$ 1,421,521	$ 1,421,521	$ 1,421,521		$ 10,258,586
32												
33	**Peaking Supply**											
34	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 28 * Sch 5C ln 26 x days	[redacted]								
35	Granite Ridge Demand	peak	Sch 5B, ln 29 * Sch 5C ln 47 x days									
36	DOMAC Demand FLS-160	peak	Per Contract									
37	Subtotal Peaking Demand Chargs			$ 2,023,704	$ 337,284	$ 404,784	$ 404,784	$ 404,784	$ 404,784	$ 337,284		$ 4,317,407
38												
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 3,753,160	$ 1,759,861	$ 1,827,396	$ 1,827,396	$ 1,827,326	$ 1,827,396	$ 1,759,861		$ 14,582,397
40												
41	Less Transportation Capacity Credit			$ (801,827)	$ (343,016)	$ (356,180)	$ (356,180)	$ (356,166)	$ (356,180)	$ (343,016)		$ (2,912,564)
42												
43	**Total Supply, Pipeline & Peaking Demand**			$ 2,951,333	$ 1,416,845	$ 1,471,217	$ 1,471,217	$ 1,471,160	$ 1,471,217	$ 1,416,845		$ 11,669,833
44						**THIS PAGE HAS BEEN REDACTED**						
45	**Storage**											
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 51 x days	$ 10,587	$ 1,765	$ 1,765	$ 1,765	$ 1,765	$ 1,765	$ 1,765		$ 21,174
47	Dominion - Storage	peak	Sch 5B, ln 34 * 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 35 * 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 37 * 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 38 * 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 39 * Sch 5C ln 61 x days	222,809	39,538	39,538	39,538	39,538	39,538	39,538		460,035
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 62 x days	223,916	39,010	39,010	39,010	39,010	39,010	39,010		457,975
53												
54	**Subtotal Storage Demand Costs**			$ 771,454	$ 132,669	$ 132,669	$ 132,669	$ 132,669	$ 132,669	$ 132,669		$ 1,567,467
55												
56	Less Transportation Capacity Credit			$ (164,814)	$ (25,859)	$ (25,859)	$ (25,859)	$ (25,859)	$ (25,859)	$ (25,859)		$ (319,965)
57												
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 606,640	$ 106,810	$ 106,810	$ 106,810	$ 106,810	$ 106,810	$ 106,810		$ 1,247,501
59												
60	**Total Demand Charges**		ln 39 + ln 54	$ 4,524,614	$ 1,892,530	$ 1,960,065	$ 1,960,065	$ 1,959,995	$ 1,960,065	$ 1,892,530		$ 16,149,864
61												
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (966,641)	$ (368,875)	$ (382,038)	$ (382,038)	$ (382,024)	$ (382,038)	$ (368,875)		$ (3,232,529)
63												
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 3,557,973	$ 1,523,655	$ 1,578,027	$ 1,578,027	$ 1,577,970	$ 1,578,027	$ 1,523,655		$ 12,917,335
65												
66												

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Demand Volumes

	Peak	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
(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 Z5-Z6	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
Tenn Gas Pipeline (Concord Lateral)		72694 Z6-Z6	4,000	4,000	4,000	4,000	4,000	4,000
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 Parkway 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								
Tenn Gas Pipeline (Concord Lateral)	peak		26,000	26,000	26,000	26,000	26,000	26,000
Granite Ridge Demand	peak		15,000	15,000	15,000	15,000	15,000	15,000
DOMAC Liquid Demand Charge	peak	FLS-160	0	2,850	2,850	2,850	2,850	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

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ENERGY NORTH NATURAL GAS, INC. **REDACTED**
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Demand Rates

				Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Nov - Apr
Tariff Rates				30	31	31	29	31	30	182
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagra Supply		[redacted]		[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$6.5971	First Revised Sheet No. 4	$0.2199	$0.2128	$0.2128	$0.2275	$0.2128	$0.2199	$0.2176
Tenn Gas Pipeline	33371 Z5-Z6	$10.7923	2nd Sub 2nd Rev Sheet No.14	$0.3597	$0.3481	$0.3481	$0.3721	$0.3481	$0.3597	$0.3560
Tenn Gas Pipeline	2302 Z5-Z6	$10.7923	2nd Sub 2nd Rev Sheet No.14	$0.3597	$0.3481	$0.3481	$0.3721	$0.3481	$0.3597	$0.3560
Tenn Gas Pipeline	8587 Z0-Z6	$33.0885	2nd Sub 2nd Rev Sheet No.14	$1.1030	$1.0674	$1.0674	$1.1410	$1.0674	$1.1030	$1.0915
Tenn Gas Pipeline	8587 Z1-Z6	$29.4677	2nd Sub 2nd Rev Sheet No.14	$0.9823	$0.9506	$0.9506	$1.0161	$0.9506	$0.9823	$0.9721
Tenn Gas Pipeline	8587 Z4-Z6	$12.1681	2nd Sub 2nd Rev Sheet No.14	$0.4056	$0.3925	$0.3925	$0.4196	$0.3925	$0.4056	$0.4014
TGP Dracut	42076 FTA Z6-Z6	$7.4442	2nd Sub 2nd Rev Sheet No.14	$0.2481	$0.2401	$0.2401	$0.2567	$0.2401	$0.2481	$0.2456
TGP Concord Lateral	72694 Z6-Z6	$12.1700	Per contract	$0.4057	$0.3926	$0.3926	$0.4197	$0.3926	$0.4057	$0.4015
Portland Natural Gas	FT-1999-001	$40.2456	Part 4.1 v.2.0.0	$1.3415	$1.2982	$1.2982	$1.3878	$1.2982	$1.3415	$1.3276
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$12.1681	2nd Sub 2nd Rev Sheet No.14	$0.4056	$0.3925	$0.3925	$0.4196	$0.3925	$0.4056	$0.4014
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$12.1681	2nd Sub 2nd Rev Sheet No.14	$0.4056	$0.3925	$0.3925	$0.4196	$0.3925	$0.4056	$0.4014
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$10.7923	2nd Sub 2nd Rev Sheet No.14	$0.3597	$0.3481	$0.3481	$0.3721	$0.3481	$0.3597	$0.3560
National Fuel	FST 2358	$3.3612	4.010 Version 1.0.0 Pg 2	$0.1120	$0.1084	$0.1084	$0.1159	$0.1084	$0.1120	$0.1109
ANE Union Gas		$2.3320								
TransCanada PipeLines Limited		$10.1678	Union Parkway to Iroquois							
Delivery Pressure Demand Charge		1.0379	Union Parkway to Iroquois							
Sub Total Demand Charges		13.5376								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		1.0100	08/22/2011							
Demand Rate/US$		$14.4264		$0.4809	$0.4654	$0.4654	$0.4975	$0.4654	$0.4809	$0.4759
Peaking										
Granite Ridge Demand		[redacted]		[redacted]						
DOMAC Demand FLS-160										
Storage										
Dominion - Demand	GSS 300076	$1.8892	Rec No 10.30 Ver 2.0.0	$0.0630	$0.0609	$0.0609	$0.0651	$0.0609	$0.0630	$0.0622
Dominion - Capacity	GSS 300076	$0.0145	Rec No 10.30 Ver 2.0.0	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.9037		$0.0635	$0.0614	$0.0614	$0.0656	$0.0614	$0.0635	$0.0627
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0.2071	$0.2071	$0.2213	$0.2071	$0.2140	$0.2113
National Fuel - Demand	FSS-1 2357	$2.1556	4.020 Version 0.0.0 Pg 1	$0.0719	$0.0695	$0.0695	$0.0743	$0.0695	$0.0719	$0.0710
National Fuel - Capacity	FSS-1 2357	$0.0432	4.020 Version 0.0.0 Pg 1	$0.0014	$0.0014	$0.0014	$0.0015	$0.0014	$0.0014	$0.0014
		$2.1988		$0.0733	$0.0709	$0.0709	$0.0758	$0.0709	$0.0733	$0.0724
Tenn Gas Pipeline	FS-MA	$1.8100	2nd Sub 2nd Rev Sheet No.61	$0.0603	$0.0584	$0.0584	$0.0624	$0.0584	$0.0603	$0.0596
Tenn Gas Pipeline - Space	FS-MA	$0.0250	2nd Sub 2nd Rev Sheet No.61	$0.0008	$0.0008	$0.0008	$0.0009	$0.0008	$0.0008	$0.0008
		$1.8350		$0.0612	$0.0592	$0.0592	$0.0633	$0.0592	$0.0612	$0.0604

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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 TARIFF RECORD 10.31)
RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [5] Surcharge (6)	EPCA [6] Surcharge (7)	FERC ACA (8)	Current Rate (9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0664	$0.0255	($0.0054)	$0.0043	-	$1.8892
	Storage Capacity	$0.0145	-	-	-	-	-	$0.0145
	Injection Charge	$0.0154	-	$0.0081	$0.0001	$0.0006	-	$0.0242
	Withdrawal Charge	$0.0154	-	-	$0.0001	$0.0006	$0.0019	$0.0180
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0007	-	-	$0.0053
	Demand Charge Adjustment	$21.5808	$0.7968	$0.3060	($0.0648)	$0.0516	-	$22.6704
	From Customers Balance	$0.6163	$0.0147	$0.0056	($0.0011)	$0.0016	$0.0019	$0.6390
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0664	$0.0255	($0.0054)	$0.0043	-	$2.3021
	Storage Capacity	$0.0369	-	-	-	-	-	$0.0369
	Injection Charge	$0.0154	-	$0.0081	$0.0001	$0.0006	-	$0.0242
	Withdrawal Charge	$0.0154	-	-	$0.0001	$0.0006	$0.0019	$0.0180
	Authorized Overruns	$1.0657	$0.0147	$0.0056	($0.0011)	$0.0016	$0.0019	$1.0884
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0008	($0.0002)	$0.0001	-	$0.0765
	Injection Charge	$0.0154	-	$0.0081	$0.0001	$0.0006	-	$0.0242
	Withdrawal Charge	$0.0154	-	-	$0.0001	$0.0006	$0.0019	$0.0180
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0147	$0.0056	($0.0011)	$0.0016	$0.0019	$0.6390
	Excess Injection Charge	$0.2245	-	$0.0081	$0.0001	$0.0006	-	$0.2333

[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 $0.6210. Daily Capacity Release Rate for GSS-E per Dt is $1.0704.
[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) ----------------

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

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

(Footnotes continued on Sheet 4.01)

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

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

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

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

Rate Sch. (1)	Rate Component 1/ (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	FERC ACA (6)	Current Rate 2/ (7)
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
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
X-58 Conversion Surcharge							
	Reservation	(Max)	0.1221	-	-	-	$0.1221
		(Min)	-	-	-	-	-
	Commodity	(Max)	-	-	-	-	-
		(Min)	-	-	-	-	-

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*Gathering rates applicable to Transporter's transportation services are set forth in Section 4.040

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.

2/ 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%.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component 1/ (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 4/			0.0702	0.0019	$0.0721
	Max. Volumetric Cap. Rate 5/			0.0014	-	$0.0014
	Storage Balance Transfer	(Max)	6/	3.8600	-	$3.8600
		(Min)	6/	0.0000	-	$0.0000
ISS	Injection	(Max)		1.0635	0.0019	$1.0654
		(Min)		0.0000	-	$0.0000
	Storage Balance Transfer	(Max)	6/	3.8600	-	$3.8600
		(Min)	6/	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 4/			0.0709	0.0019	$0.0728
	Max. Volumetric Cap. Rate 5/			0.0014	-	$0.0014
	Storage Balance Transfer	(Max)	6/	3.8600	-	$3.8600
		(Min)	6/	0.0000	-	$0.0000

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.
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/ Unit Dth Rates per day.
4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ 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	$40.2456	---------	$40.2456
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	---------	$76.4666
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0019	$00.0019
	-- Minimum	$00.0000	$00.0019	$00.0019
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	---------	$27.0128
	--Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0019	$00.4369
	--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 6.18 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	$7.8388		$15.0198	$19.7726	$20.1004	$25.1838	$26.6698	$33.0885
L		$7.0992						
1	$11.3219		$10.7586	$13.9042	$19.1763	$21.6140	$24.2473	$29.4677
2	$19.7726		$13.8422	$7.7920	$7.3650	$10.1388	$13.5681	$17.1056
3	$20.1004		$11.2131	$7.8416	$6.0071	$9.5356	$16.4342	$18.7169
4	$25.1838		$23.0587	$9.7077	$14.0281	$8.3057	$8.9007	$12.1681
5	$29.7879		$21.3027	$10.0699	$11.9223	$9.1155	$8.6128	$10.7923
6	$34.2674		$24.2865	$17.1056	$18.7169	$15.2862	$8.4620	$7.4442

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.2577		$0.4938	$0.6501	$0.6608	$0.8280	$0.8768	$1.0878
L		$0.2334						
1	$0.3722		$0.3537	$0.4571	$0.6305	$0.7106	$0.7972	$0.9688
2	$0.6501		$0.4551	$0.2562	$0.2421	$0.3333	$0.4461	$0.5624
3	$0.6608		$0.3686	$0.2578	$0.1975	$0.3135	$0.5403	$0.6154
4	$0.8280		$0.7581	$0.3192	$0.4612	$0.2731	$0.2926	$0.4000
5	$0.9793		$0.7004	$0.3311	$0.3920	$0.2997	$0.2832	$0.3548
6	$1.1266		$0.7985	$0.5624	$0.6154	$0.5026	$0.2782	$0.2447

Maximum Reservation Rates 2 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$7.8388		$15.0198	$19.7726	$20.1004	$25.1838	$26.6698	$33.0885
L		$7.0992						
1	$11.3219		$10.7586	$13.9042	$19.1763	$21.6140	$24.2473	$29.4677
2	$19.7726		$13.8422	$7.7920	$7.3650	$10.1388	$13.5681	$17.1056
3	$20.1004		$11.2131	$7.8416	$6.0071	$9.5356	$16.4342	$18.7169
4	$25.1838		$23.0587	$9.7077	$14.0281	$8.3057	$8.9007	$12.1681
5	$29.7879		$21.3027	$10.0699	$11.9223	$9.1155	$8.6128	$10.7923
6	$34.2674		$24.2865	$17.1056	$18.7169	$15.2862	$8.4620	$7.4442

Notes:
1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge of $0.00 for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions.

RATE SCHEDULE NET 284 1/, 2/
==

Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions are listed on Sheet No. 32. For service rendered entirely by displacement, Shipper shall render only the quantity of gas assoicated with Losses of 0.09%.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA			
Deliverability Rate	$2.81	$2.81 1/	
Space Rate	$0.0286	$0.0286 1/	
Injection Rate	$0.0073	$0.0073 3/	1.59%
Withdrawal Rate	$0.0073	$0.0073 3/	
Overrun Rate	$0.3372	$0.3372 3/	
FIRM STORAGE SERVICE (FS) - MARKET AREA			
Deliverability Rate	$1.81	$1.81 1/	
Space Rate	$0.0250	$0.0250 1/	
Injection Rate	$0.0204	$0.0204 3/	1.59%
Withdrawal Rate	$0.0204	$0.0204 3/	
Overrun Rate	$0.2172	$0.2172 3/	

1/ Includes a per Dth charge of $0.00 for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions.

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions associated with Losses is equal to 0.09%.

3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

TRANSPORTATION RATES

(A) Applicability

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

(B) Services

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

(C) Rates

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

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

Authorized Overrun (3)

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

Transportation Overrun	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Charges: Fuel Ratio %	AND	Commodity Charge Rate/GJ
Dawn to Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.077
Dawn to Kirkwall				$0.065
Parkway to Dawn				$0.077
Parkway (TCPL) Overrun (4)	n/a	0.540%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.095

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Transportation Tolls
Approved Mainline Revised Interim Tolls effective March 1, 2011

System Average Unit Cost of Transportation

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

Storage Transportation Service

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

Firm Transportation - Short Notice

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

Delivery Pressure

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

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

Union Dawn Receipt Point Surcharge

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

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Revised Interim Tolls effective March 1, 2011

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

Daily currency converter

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

Currency Converter (Using rates from August 22, 2011)

Amount: 1.00 **cash rate**:

From: Canadian Dollar

To: U.S. dollar

Convert

Answer: 1.01

Exchange Rate: 1.0100

Summary: On 22 August 2011, 1.00 Canadian Dollar(s) = 1.01 U.S. dollar(s), at an exchange rate of 1.0100 (using nominal rate).

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1 **ENERGY NORTH NATURAL GAS, INC.** **REDACTED**

2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln	For Month of:	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak 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 63 * ln 102	[redacted]						
13	Niagara Supply	ln 64 * ln 107							
14	TGP Supply (Direct)	ln 65 * ln 123							
15	Dracut Supply 1 - Baseload	ln 66 * ln 112							
16	Dracut Supply 2 - Swing	ln 67 * ln 117							
17	City Gate Delivered Supply	ln 68 * ln 129							
18	LNG Truck	ln 69 * ln 131							
19	Propane Truck	ln 70 * ln 133							
20	PNGTS	ln 71 * ln 138							
21	Granite Ridge	ln 72 * ln 143							
22									
23	Subtotal Pipeline Gas Costs		$ 5,379,492	$ 5,429,171	$ 6,998,934	$ 6,528,650	$ 6,866,333	$ 4,587,161	$ 35,789,742
24									
25	**Volumetric Transportation Costs**								
26	Dawn Supply	ln 63 * ln 190	[redacted]						
27	Niagara Supply	ln 64 * ln 201							
28	TGP Supply (Direct)	ln 65 * ln 228							
29	Dracut Supply 1 - Baseload	ln 66 * ln 249							
30	Dracut Supply 2 - Swing	ln 67 * ln 249							
31	City Gate Delivered Supply	ln 68 * ln 249							
32	TGP Storage - Withdrawals	ln 77 * ln 165							
33									
34	**Total Volumetric Transportation Costs**		$ 169,109	$ 221,587	$ 232,683	$ 212,230	$ 170,614	$ 216,454	$ 1,222,677
35									
36	**Less - Gas Refill:**								
37	LNG Truck	ln 86 * ln 150	[redacted]						
38	Propane	ln 87 * ln 151							
39	TGP Storage Refill	ln 88 * ln 121							
40	Storage Refill (Trans.)	ln 88 * ln 228							
41									
42	Subtotal Refills		$ (323,317)	$ (10,230)	$ (309,144)	$ (10,104)	$ (20,788)	$ (869,171)	$ (1,542,755)
43									
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 5,225,284	$ 5,640,528	$ 6,922,473	$ 6,730,776	$ 7,016,160	$ 3,934,444	$ 35,469,665
45									
46	**Storage Gas:**								
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 40,630	$ 2,915,960	$ 3,132,782	$ 2,615,535	$ 117,592	$ -	$ 8,822,497
48									
49	**Produced Gas:**								
50	LNG Vapor	ln 80 * ln 145	[redacted]						
51	Propane	ln 81 * ln 147							
52									
53	**Total Produced Gas**	ln 50 + ln 51	$ 9,720	$ 10,101	$ 331,289	$ 10,077	$ 10,413	$ 10,054	$ 381,653
54									
55									
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 5,275,633	$ 8,566,589	$ 10,386,543	$ 9,356,388	$ 7,144,164	$ 3,944,498	$ 44,673,815
57									
58									

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1 **ENERGY NORTH NATURAL GAS, INC.** **REDACTED**

2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line	For Month of:	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
59									
60	**Volumes (Therms)**								
61									
62	**Pipeline Gas:**	See Schedule 11A							
63	Dawn Supply		907,335	998,310	998,310	933,903	998,310	-	4,836,170
64	Niagara Supply		754,368	779,326	779,326	728,606	779,326	594,961	4,415,913
65	TGP Supply (Direct)		5,929,481	5,390,071	5,390,071	5,042,273	5,390,071	6,976,097	34,118,064
66	Dracut Supply 1 - Baseload		-	2,495,776	2,495,776	2,334,758	-	-	7,326,310
67	Dracut Supply 2 - Swing		4,247,650	754,368	1,524,034	2,135,096	6,431,051	2,569,844	17,662,044
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		22,542	23,348	689,961	22,542	46,695	-	805,089
70	Propane Truck		-	-	-	-	-	-	-
71	PNGTS		64,407	82,119	89,365	80,509	73,263	53,136	442,799
72	Granite Ridge		-	-	-	-	-	-	-
73									
74	Subtotal Pipeline Volumes		11,925,784	10,523,319	11,966,844	11,277,688	13,718,718	10,194,038	69,606,390
75									
76	**Storage Gas:**								
77	TGP Storage		83,729	6,009,185	6,456,009	5,390,071	242,332	-	18,181,326
78									
79	**Produced Gas:**								
80	LNG Vapor		22,542	23,348	742,292	22,542	23,348	22,542	856,615
81	Propane		-	-	-	-	-	-	-
82									
83	Subtotal Produced Gas		22,542	23,348	742,292	22,542	23,348	22,542	856,615
84									
85	**Less - Gas Refill:**								
86	LNG Truck		(22,542)	(23,348)	(689,961)	(22,542)	(46,695)	-	(805,089)
87	Propane		-	-	-	-	-	-	-
88	TGP Storage Refill		(713,309)	-	-	-	-	(1,846,874)	(2,560,183)
89									
90	Subtotal Refills		(735,851)	(23,348)	(689,961)	(22,542)	(46,695)	(1,846,874)	(3,365,272)
91									
92	**Total Sendout Volumes**		11,296,205	16,532,504	18,475,184	16,667,759	13,937,702	8,369,706	85,279,059
93									
94									
95									

1	**ENERGY NORTH NATURAL GAS, INC.**								**REDACTED**
2	**d/b/a National Grid NH**								
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
96	**Gas Costs and Volumetric Transportation Rates**								**REDACTED**
97									
98	**Pipeline Gas:**								
99	**Dawn Supply**								Average Rate
100	NYMEX Price	Sch 7, ln 10/10	[redacted]						
101	Basis Differential								
102	**Net Commodity Costs**								
103									
104	**Niagara Supply**								
105	NYMEX Price	Sch 7, ln 10/10	[redacted]						
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Dracut Supply 1 - Baseload**								
110	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 2 - Swing**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119									
120	**TGP Supply (Direct)**								
121	NYMEX Price	Sch 7, ln 10/10	[redacted]						
122	Basis Differential								
123	**Net Commodity Costs**								
124									
125									
126	**City Gate Delivered Supply**								
127	NYMEX Price	Sch 7, ln 10/10	[redacted]						
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131	**LNG Truck**	Sch 7, ln 10/10	**$0.4162**	**$0.4382**	**$0.4481**	**$0.4482**	**$0.4452**	**$0.4408**	**$0.4394**
132									
133	**Propane Truck**	NYMEX - Propane	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
134									
135	**PNGTS**								
136	NYMEX Price	Sch 7, ln 10/10	[redacted]						
137	Additional Cost								
138	**Net Commodity Cost**								
139									
140	**Granite Ridge**								
141	NYMEX Price	Sch 7, ln 10/10	[redacted]						
142	Additional Cost								
143	**Net Commodity Cost**								
144									
145	**LNG Vapor (Storage)**	Sch 16, ln 95 /10	**$0.4312**	**$0.4326**	**$0.4463**	**$0.4470**	**$0.4460**	**$0.4460**	**$0.4415**
146									
147	**Propane**	Sch 16, ln 66 /10	**$1.4444**	**$1.4444**	**$1.4444**	**$1.4444**	**$1.4444**	**$1.4444**	**$1.4444**
148									
149	**Storage Refill:**								
150	**LNG Truck**	ln 131	**$0.4162**	**$0.4382**	**$0.4481**	**$0.4482**	**$0.4452**	**$0.4408**	**$0.4415**
151	**Propane**	ln 133	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$1.4444**
152									
153					**THIS PAGE HAS BEEN REDACTED**				

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1 **ENERGY NORTH NATURAL GAS, INC.** **REDACTED**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line	For Month of:	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									**REDACTED**
155									
156	**TGP Storage**								Average Rate
157	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.4853	$0.4853	$0.4853	$0.4853	$0.4853	$0.4853	$0.4853
158									
159	TGP - Max Commodity - Z 4-6	2nd Sub 1st Rev Sheet No.15	$0.00259	$0.00259	$0.00259	$0.00259	$0.00259	$0.00259	$0.00259
160	TGP - Max Comm. ACA Rate - Z 4-6	2nd Sub 1st Rev Sheet No.15	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
161	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.00278	$0.00278	$0.00278	$0.00278	$0.00278	$0.00278	$0.00278
162	TGP - Fuel Charge % - Z 4-6	Sub 1st Rev Sheet No. 32	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00514	$0.00514	$0.00514	$0.00514	$0.00514	$0.00514	$0.00514
164	TGP - Withdrawal Charge	2nd Sub 2nd Rev Sheet No.61	$0.00204	$0.00204	$0.00204	$0.00204	$0.00204	$0.00204	$0.00204
165	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.00996	$0.00996	$0.00996	$0.00996	$0.00996	$0.00996	$0.00996
166									
167	**Total TGP - Comm. & Vol. Trans. Rate**	ln 157 + ln 165	**$0.49521**	**$0.49521**	**$0.49521**	**$0.49521**	**$0.49521**	**$0.49521**	**$0.49521**
168									
169									
170	**Per Unit Volumetric Transportation Rates**								
171	**Dawn Supply Volumetric Transportation Charge**								
172	**Commodity Costs**	ln 102	**$0.4542**	**$0.4772**	**$0.4821**	**$0.4812**	**$0.4822**	**$0.4776**	**$0.4757**
173									
174	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00198	$0.00198	$0.00198	$0.00198	$0.00198	$0.00198	$0.00198
175	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
176	Conversion Rate to US$	08/22/2011	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100
177	Commodity Rate/US$	ln 174 x ln 175 x ln 176	$0.00211	$0.00211	$0.00211	$0.00211	$0.00211	$0.00211	$0.00211
178	TransCanada Fuel %	Union Parkway to Iroquois	0.98%	1.06%	1.24%	1.21%	0.88%	1.12%	1.08%
179	TransCanada Fuel * Percentage	ln 172 x ln 178	$0.00445	$0.00506	$0.00598	$0.00582	$0.00424	$0.00535	$0.00515
180	Subtotal TransCanada		**$0.00656**	**$0.00717**	**$0.00809**	**$0.00794**	**$0.00636**	**$0.00746**	**$0.00726**
181	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
182	IGTS - Z1 RTS ACA Rate Commodity	First Revised Sheet 4A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
183	IGTS - Z1 RTS Deferred Asset Surcharge	First Revised Sheet 4A	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
184	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**
185	TGP NET-NE - Comm. Segments 3 & 4	2nd Sub 1st Rev Sheet No.15	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
186	IGTS -Fuel Use Factor - Percentage	First Revised Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
187	IGTS -Fuel Use Factor - Fuel * Percentage	ln 172 x ln 186	**$0.00454**	**$0.00477**	**$0.00482**	**$0.00481**	**$0.00482**	**$0.00478**	**$0.00476**
188	TGP NET-284 - Fuel Charge % Z 4-6	Original Sheet No. 105	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%
189	TGP NET-284 -Fuel Use Factor - Fuel * %	ln 172 x ln 188	**$0.00350**	**$0.00367**	**$0.00371**	**$0.00371**	**$0.00371**	**$0.00368**	**$0.00366**
190	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01531**	**$0.01633**	**$0.01733**	**$0.01716**	**$0.01560**	**$0.01663**	**$0.01639**
191									
192									
193	**Niagara Supply Volumetric Transportation Charge**								
194	**Commodity Costs**	Ln 107	[redacted]						
195									
196	TGP FTA - FTA Z 5-6 Comm. Rate	2nd Sub 1st Rev Sheet No.15							
197	TGP FTA - FTA Z 5-6 - ACA Rate	2nd Sub 1st Rev Sheet No.15							
198	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
199	TGP FTA Fuel Charge % Z 5-6	Sub 1st Rev Sheet No. 32							
200	TGP FTA Fuel * Percentage	ln 194 x ln 199							
201	**Total Volumetric Transportation Rate - Niagra Supply**								
202									
203									
204					**THIS PAGE HAS BEEN REDACTED**				

Ln		Reference							
1	**ENERGY NORTH NATURAL GAS, INC.**								**REDACTED**
2	**d/b/a National Grid NH**								
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
205									**REDACTED**
206									
207	**TGP Direct Volumetric Transportation Charge**								Average Rate
208	**Commodity Costs**	Ln 121	[redacted]						
209									
210	TGP - Max Comm. Base Rate - Z 0-6	2nd Sub 1st Rev Sheet No.15	$0.00974	$0.00974	$0.00974	$0.00974	$0.00974	$0.00974	$0.00974
211	TGP - Max Commodity ACA Rate - Z 0-6	2nd Sub 1st Rev Sheet No.15	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
212	Subtotal TGP - Max Comm. Rate Z 0-6		$0.00993	$0.00993	$0.00993	$0.00993	$0.00993	$0.00993	$0.00993
213	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
214	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00324**	**$0.00324**	**$0.00324**	**$0.00324**	**$0.00324**	**$0.00324**	**$0.00324**
215	TGP - Max Comm. Base Rate - Z 1-6	2nd Sub 1st Rev Sheet No.15	$0.00845	$0.00845	$0.00845	$0.00845	$0.00845	$0.00845	$0.00845
216	TGP - Max Commodity ACA Rate - Z 1-6	2nd Sub 1st Rev Sheet No.15	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
217	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.00864	$0.00864	$0.00864	$0.00864	$0.00864	$0.00864	$0.00864
218	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
219	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.00582**	**$0.00582**	**$0.00582**	**$0.00582**	**$0.00582**	**$0.00582**	**$0.00582**
220	TGP - Fuel Charge % - Z 0 -6	Sub 1st Rev Sheet No. 32	3.91%	3.91%	3.91%	3.91%	3.91%	7.42%	4.50%
221	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
222	Prorated TGP Fuel Charge % - Z 0-6		1.27%	1.27%	1.27%	1.27%	1.27%	2.42%	1.47%
223	TGP - Fuel Charge % - Z 1 -6	Sub 1st Rev Sheet No. 32	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
224	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.29%	2.29%	2.29%	2.29%	2.29%	2.29%	2.29%
226	TGP - Fuel Charge % - Z 0-6	ln 208 x ln 222	**$0.00531**	**$0.00559**	**$0.00571**	**$0.00571**	**$0.00567**	**$0.01066**	**$0.00644**
227	TGP - Fuel Charge % - Z 1-6	ln 208 x ln 225	**$0.00954**	**$0.01004**	**$0.01027**	**$0.01027**	**$0.01020**	**$0.01010**	**$0.01007**
228	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.02390**	**$0.02469**	**$0.02504**	**$0.02505**	**$0.02494**	**$0.02982**	**$0.02557**
229									
230	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
231	**Commodity Costs**	Ln 121	[redacted]						
232									
233	TGP - Max Comm. Base Rate - Z 6-6	2nd Sub 1st Rev Sheet No.15	$0.00056	$0.00056	$0.00056	$0.00056	$0.00056	$0.00056	$0.00056
234	TGP - Max Commodity ACA Rate - Z 6-6	2nd Sub 1st Rev Sheet No.15	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
235	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00075**	**$0.00075**	**$0.00075**	**$0.00075**	**$0.00075**	**$0.00075**	**$0.00075**
236	TGP - Fuel Charge % - Z 6-6	Sub 1st Rev Sheet No. 32	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
237	TGP - Fuel Charge	ln 231 x ln 236	**$0.00104**	**$0.00110**	**$0.00112**	**$0.00112**	**$0.00111**	**$0.00110**	**$0.00110**
238	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00179**	**$0.00185**	**$0.00187**	**$0.00187**	**$0.00186**	**$0.00185**	**$0.00185**
239									
240									
241	**TGP Dracut**								
242	**Commodity Costs - NYMEX Price**	Ln 112	[redacted]						
243									
244	TGP - Trans Charge - Comm. - Z 6-6	2nd Sub 1st Rev Sheet No.15							
245	TGP - Trans Charge - ACA Rate - Z6-6	2nd Sub 1st Rev Sheet No.15							
246	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
247	TGP - Fuel Charge % - Z 6-6	Sub 1st Rev Sheet No. 32							
248	TGP - Fuel Charge	ln 242 x ln 247							
249	**Total Volumetric Transportation Rate - TGP Dracut**								
250									
251						**THIS PAGE HAS BEEN REDACTED**			

RATES (All in $ Per Dth)

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

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

(Footnotes continued on Sheet 4.01)

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1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).
2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.
3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.
4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:		
Commodity	0.0019	
DEFERRED ASSET SURCHARGE:		
Commodity		
Zone 1	0.0003	
Zone 2	0.0002	
Inter-Zone	0.0005	
MEASUREMENT VARIANCE/FUEL USE FACTOR:		
Minimum		0.00%
Maximum (Non-Eastchester Shipper)		1.00%
Maximum (Eastchester Shipper)		4.50%
Maximum (Brookfield Shipper)		1.20%

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	$0.0083		$0.0305	$0.0469	$0.0582	$0.0702	$0.0797	$0.0974
L		$0.0031						
1	$0.0110		$0.0215	$0.0390	$0.0475	$0.0589	$0.0720	$0.0845
2	$0.0469		$0.0231	$0.0029	$0.0073	$0.0156	$0.0281	$0.0401
3	$0.0582		$0.0475	$0.0073	$0.0006	$0.0226	$0.0332	$0.0460
4	$0.0702		$0.0544	$0.0229	$0.0278	$0.0077	$0.0130	$0.0259
5	$0.0797		$0.0720	$0.0281	$0.0332	$0.0129	$0.0127	$0.0187
6	$0.0974		$0.0845	$0.0401	$0.0460	$0.0242	$0.0115	$0.0056

Minimum Commodity Rates 1/, 2/ 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0132		$0.0438	$0.0665	$0.0821	$0.0987	$0.1118	$0.1356
L		$0.0060						
1	$0.0169		$0.0314	$0.0556	$0.0673	$0.0831	$0.1012	$0.1178
2	$0.0665		$0.0336	$0.0057	$0.0118	$0.0233	$0.0405	$0.0564
3	$0.0821		$0.0673	$0.0118	$0.0025	$0.0329	$0.0476	$0.0646
4	$0.0987		$0.0769	$0.0334	$0.0401	$0.0123	$0.0197	$0.0368
5	$0.1118		$0.1012	$0.0405	$0.0476	$0.0195	$0.0193	$0.0269
6	$0.1356		$0.1178	$0.0564	$0.0646	$0.0345	$0.0169	$0.0088

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0132		$0.0438	$0.0665	$0.0821	$0.0987	$0.1118	$0.1356
L		$0.0060						
1	$0.0169		$0.0314	$0.0556	$0.0673	$0.0831	$0.1012	$0.1178
2	$0.0665		$0.0336	$0.0057	$0.0118	$0.0233	$0.0405	$0.0564
3	$0.0821		$0.0673	$0.0118	$0.0025	$0.0329	$0.0476	$0.0646
4	$0.0987		$0.0769	$0.0334	$0.0401	$0.0123	$0.0197	$0.0368
5	$0.1118		$0.1012	$0.0405	$0.0476	$0.0195	$0.0193	$0.0269
6	$0.1356		$0.1178	$0.0564	$0.0646	$0.0345	$0.0169	$0.0088

Notes:

1/ includes a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions are listed on Sheet No. 32. For service that is rendered entirely by displacement, shipper shall render only the quantity of gas associated with Losses of 0.09%.

3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

4/ Includes a per Dth charge for the Hurricane Surcharge Adjustment per Article XXXIX of the General Terms and Conditions and listed on Sheet No. 34.

RATE SCHEDULE NET 284 1/, 2/
==

Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions are listed on Sheet No. 32. For service rendered entirely by displacement, Shipper shall render only the quantity of gas assoicated with Losses of 0.09%.

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

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

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

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA			
Deliverability Rate	$2.81	$2.81 1/	
Space Rate	$0.0286	$0.0286 1/	
Injection Rate	$0.0073	$0.0073 3/	1.59%
Withdrawal Rate	$0.0073	$0.0073 3/	
Overrun Rate	$0.3372	$0.3372 3/	
FIRM STORAGE SERVICE (FS) - MARKET AREA			
Deliverability Rate	$1.81	$1.81 1/	
Space Rate	$0.0250	$0.0250 1/	
Injection Rate	$0.0204	$0.0204 3/	1.59%
Withdrawal Rate	$0.0204	$0.0204 3/	
Overrun Rate	$0.2172	$0.2172 3/	

1/ Includes a per Dth charge of $0.00 for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions.
2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions associated with Losses is equal to 0.09%.
3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
RATE SCHEDULE IS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA			
Space Rate	$0.1000	$0.1000 1/	
Injection Rate	$0.0204	$0.0204 3/	1.59%
Withdrawal Rate	$0.0204	$0.0204 3/	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA			
Space Rate	$0.1050	$0.1050 1/	
Injection Rate	$0.0073	$0.0073 3/	1.59%
Withdrawal Rate	$0.0073	$0.0073 3/	

1/ Includes a per Dth charge of $0.00 for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions.
2/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions associated with Losses is equal to 0.09%.
3/ Includes a per Dth charge for EPCR Adjustment per Article XXXVIII of the General Terms and Conditions and listed on Sheet No. 33.

NET-284 RATE SCHEDULE (continued)

5. SHIPPERS

The Shippers to which this Rate Schedule is available, each Shipper's Transportation Quantity and the rate zone applicable to the transportation service provided by Transporter are as follows:

Shipper	Transportation Quantity (Dth)	Rate Zones Receipt	Rate Zones Delivery
Bay State (from Granite) - Pleasant St.	3,706	5	6
Bay State (from Granite) - Agawam	6,068	5	6
Boston Gas d/b/a National Grid	35,000	5	6
Boston Gas d/b/a National Grid	8,600	5	6
Barclays Bank PLC	14,010	5	6
EnergyNorth Natural Gas, Inc. d/b/a National Grid	4,000	5	6
Essex Gas Company d/b/a National Grid	2,000	5	6
Iroquois Gas Transmission (Connecticut Natural, Yankee Gas)	37,000	6	6
Lockport Energy Associates	13,184	1	5
New York State Electric & Gas Corp	14,816	1	5
Northern Utilities (from Granite) Pleasant St.	844	5	6
Northern Utilities (from Granite) Agawam	1,382	5	6
The Narragansett Electric Company d/b/a National Grid	1,000	5	6
Yankee Gas Services Company (Wright)	9,000	5	6
Total	150,610		

TransCanada
In business to deliver

Transportation Tolls
Approved Mainline Revised Interim Tolls effective March 1, 2011

System Average Unit Cost of Transportation

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

Storage Transportation Service

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

Firm Transportation - Short Notice

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

Delivery Pressure

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

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

Union Dawn Receipt Point Surcharge

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

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Revised Interim Tolls effective March 1, 2011

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

TRANSCANADA FUEL RATIOS

November 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.2794**	**0.98**	0.29

February 2011

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.2794**	**1.21**	0.52

December 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.2794**	**1.06**	0.37

March 2011

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**0.88**	0.19

January 2011

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.2794**	**1.24**	0.55

April 2011

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**1.12**	0.43

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Ln		Reference							
5									Peak
6	For Month of:	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	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)		4.1621	4.3818	4.4806	4.4822	4.4518	4.4079	$ 4.3944
10	NYMEX	ln 201	4.1621	4.3818	4.4806	4.4822	4.4518	4.4079	$ 4.3944
11									
12									
13									
14									
15									
16									
17									
18									
19									
20	**II. Development of Hedging Costs and Savings**								
21									
22	**TGP (Direct) Volumes**								Total
23	Hedged Volumes (Dth)	ln 83	530,000	540,000	520,000	560,000	860,000	380,000	3,390,000
24	Market Priced Volumes (Dth)		653,883	501,785	598,752	557,464	499,876	634,090	3,445,850
25	Total Volumes (Dth)	Sch 6, lns 63 - 68 / 10	1,183,883	1,041,785	1,118,752	1,117,464	1,359,876	1,014,090	6,835,850
26									
27									Weighted Average
28	Hedge Price	ln 170	$ 4.7810	$ 5.1667	$ 5.2398	$ 5.0947	$ 4.9486	$ 4.8685	$ 5.0170
29	NYMEX Price	ln 10	$ 4.1621	$ 4.3818	$ 4.4806	$ 4.4822	$ 4.4518	$ 4.4079	$ 4.3999
30									
31	Hedged Volumes at Hedged Price	ln 23 * ln 28	$ 2,533,929	$ 2,789,994	$ 2,724,674	$ 2,853,054	$ 4,255,794	$ 1,850,046	$ 17,007,491
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29	2,205,895	2,366,172	2,329,912	2,510,032	3,828,548	1,675,015	14,915,574
33									
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32	$ 328,034	$ 423,822	$ 394,762	$ 343,022	$ 427,246	$ 175,031	$ 2,091,917
35									
36	Total Financial Hedge	ln 23	5,300,000	5,400,000	5,200,000	5,600,000	8,600,000	3,800,000	33,900,000
37	Total Underground Storage	Sch 6, Ln 77	83,729	6,009,185	6,456,009	5,390,071	242,332	-	18,181,326
38	Sub Total		5,383,729	11,409,185	11,656,009	10,990,071	8,842,332	3,800,000	52,081,326
39	Total Throughput	Sch 6, ln 92	11,296,205	16,532,504	18,475,184	16,667,759	13,937,702	8,369,706	85,279,059
40	Hedge Percentage	ln 38 / ln 39	48%	69%	63%	66%	63%	45%	61%

00000047

Line												
1	**ENERGY NORTH NATURAL GAS, INC.**											
2	**d/b/a National Grid NH**											
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**											
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**											
5												Peak
6	For Month of:				Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41												**REDACTED**
42	Hedged Volumes (Dth)											
43	Hedge #	1	Trade Date	11-Jun-10	Swaps	[redacted]						
44	Hedge #	2	Trade Date	25-Jun-10	Swaps							
45	Hedge #	3	Trade Date	09-Jul-10	Swaps							
46	Hedge #	4	Trade Date	26-Jul-10	Swaps							
47	Hedge #	5	Trade Date	06-Aug-10	Swaps							
48	Hedge #	6	Trade Date	20-Aug-10	Swaps							
49	Hedge #	7	Trade Date	10-Sep-10	Swaps							
50	Hedge #	8	Trade Date	24-Sep-10	Swaps							
51	Hedge #	9	Trade Date	08-Oct-10	Swaps							
52	Hedge #	10	Trade Date	22-Oct-10	Swaps							
53	Hedge #	11	Trade Date	22-Nov-10	Swaps							
54	Hedge #	12	Trade Date	29-Nov-10	Swaps							
55	Hedge #	13	Trade Date	03-Dec-10	Swaps							
56	Hedge #	14	Trade Date	17-Dec-10	Swaps							
57	Hedge #	15	Trade Date	07-Jan-11	Swaps							
58	Hedge #	16	Trade Date	08-Apr-11	Swaps							
59	Hedge #	17	Trade Date	21-Apr-11	Swaps							
60	Hedge #	18	Trade Date	06-May-11	Swaps							
61	Hedge #	19	Trade Date	20-May-11	Swaps							
62	Hedge #	20	Trade Date	10-Jun-11	Swaps							
63	Hedge #	21	Trade Date	24-Jun-11	Swaps							
64	Hedge #	22	Trade Date	08-Jul-11	Swaps							
65	Hedge #	23	Trade Date	22-Jul-11	Swaps							
66	Hedge #	24	Trade Date		Swaps							
67	Hedge #	25	Trade Date		Swaps							
68	Hedge #	26	Trade Date		Swaps							
69	Hedge #	27	Trade Date		Swaps							
70	Hedge #	28	Trade Date		Swaps							
71	Hedge #	29	Trade Date		Swaps							
72	Hedge #	30	Trade Date		Swaps							
73												
74												
75												
76												
77												
78												
79												
80	Subtotal Hedge Volumes					420,000	460,000	430,000	440,000	680,000	320,000	2,750,000
81	Remaining					110,000	80,000	90,000	120,000	180,000	60,000	640,000
82	Total Volumes					530,000	540,000	520,000	560,000	860,000	380,000	3,390,000
83												
84								**THIS PAGE HAS BEEN REDACTED**				

00000048

1	**ENERGY NORTH NATURAL GAS, INC.**											
2	**d/b/a National Grid NH**											
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**											
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**											
5												Peak
6	For Month of:				Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
85	Strike Price											**REDACTED** Weighted Average
86	Hedge #	1	Trade Date	11-Jun-10	Swaps	[redacted]						
87	Hedge #	2	Trade Date	25-Jun-10	Swaps							
88	Hedge #	3	Trade Date	09-Jul-10	Swaps							
89	Hedge #	4	Trade Date	26-Jul-10	Swaps							
90	Hedge #	5	Trade Date	06-Aug-10	Swaps							
91	Hedge #	6	Trade Date	20-Aug-10	Swaps							
92	Hedge #	7	Trade Date	10-Sep-10	Swaps							
93	Hedge #	8	Trade Date	24-Sep-10	Swaps							
94	Hedge #	9	Trade Date	08-Oct-10	Swaps							
95	Hedge #	10	Trade Date	22-Oct-10	Swaps							
96	Hedge #	11	Trade Date	22-Nov-10	Swaps							
97	Hedge #	12	Trade Date	29-Nov-10	Swaps							
98	Hedge #	13	Trade Date	03-Dec-10	Swaps							
99	Hedge #	14	Trade Date	17-Dec-10	Swaps							
100	Hedge #	15	Trade Date	07-Jan-11	Swaps							
101	Hedge #	16	Trade Date	08-Apr-11	Swaps							
102	Hedge #	17	Trade Date	21-Apr-11	Swaps							
103	Hedge #	18	Trade Date	06-May-11	Swaps							
104	Hedge #	19	Trade Date	20-May-11	Swaps							
105	Hedge #	20	Trade Date	10-Jun-11	Swaps							
106	Hedge #	21	Trade Date	24-Jun-11	Swaps							
107	Hedge #	22	Trade Date	08-Jul-11	Swaps							
108	Hedge #	23	Trade Date	22-Jul-11	Swaps							
109	Hedge #	24	Trade Date		Swaps							
110	Hedge #	25	Trade Date		Swaps							
111	Hedge #	26	Trade Date		Swaps							
112	Hedge #	27	Trade Date		Swaps							
113	Hedge #	28	Trade Date		Swaps							
114	Hedge #	29	Trade Date		Swaps							
115	Hedge #	30	Trade Date		Swaps							
116												
117												
118												
119												
120												
121												
122												
123	Subtotal Weigthed Average Hedge Prices					$4.9431	$5.3032	$5.3987	$5.2618	$5.0801	$4.9549	5.1608
124	NYMEX					$4.1621	$4.3818	$4.4806	$4.4822	$4.4518	$4.4079	4.3989
125												
126								**THIS PAGE HAS BEEN REDACTED**				

00000049

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line												
5												Peak
6	For Month of:				Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
127	Hedge Dollars											**REDACTED**
128	Hedge #	1	Trade Date	11-Jun-10	Swaps	[redacted]						
129	Hedge #	2	Trade Date	25-Jun-10	Swaps							
130	Hedge #	3	Trade Date	09-Jul-10	Swaps							
131	Hedge #	4	Trade Date	26-Jul-10	Swaps							
132	Hedge #	5	Trade Date	06-Aug-10	Swaps							
133	Hedge #	6	Trade Date	20-Aug-10	Swaps							
134	Hedge #	7	Trade Date	10-Sep-10	Swaps							
135	Hedge #	8	Trade Date	24-Sep-10	Swaps							
136	Hedge #	9	Trade Date	08-Oct-10	Swaps							
137	Hedge #	10	Trade Date	22-Oct-10	Swaps							
138	Hedge #	11	Trade Date	22-Nov-10	Swaps							
139	Hedge #	12	Trade Date	29-Nov-10	Swaps							
140	Hedge #	13	Trade Date	03-Dec-10	Swaps							
141	Hedge #	14	Trade Date	17-Dec-10	Swaps							
142	Hedge #	15	Trade Date	07-Jan-11	Swaps							
143	Hedge #	16	Trade Date	08-Apr-11	Swaps							
144	Hedge #	17	Trade Date	21-Apr-11	Swaps							
145	Hedge #	18	Trade Date	06-May-11	Swaps							
146	Hedge #	19	Trade Date	20-May-11	Swaps							
147	Hedge #	20	Trade Date	10-Jun-11	Swaps							
148	Hedge #	21	Trade Date	24-Jun-11	Swaps							
149	Hedge #	22	Trade Date	08-Jul-11	Swaps							
150	Hedge #	23	Trade Date	22-Jul-11	Swaps							
151	Hedge #	24	Trade Date	00-Jan-00	Swaps							
152	Hedge #	25	Trade Date	00-Jan-00	Swaps							
153	Hedge #	26	Trade Date	00-Jan-00	Swaps							
154	Hedge #	27	Trade Date	00-Jan-00	Swaps							
155	Hedge #	28	Trade Date	00-Jan-00	Swaps							
156	Hedge #	29	Trade Date	00-Jan-00	Swaps							
157	Hedge #	30	Trade Date	00-Jan-00	Swaps							
158												
159												
160												
161												
162												
163												
164												
165	Subtotal Hedge Dollars					$2,076,102	$2,439,450	$2,321,420	$2,315,190	$3,454,470	$1,585,570	$14,192,202
166	Remaining					457,827	350,544	403,254	537,864	801,324	264,476	2,815,289
167												
168			Target Hedged Dollars			$2,533,929	$2,789,994	$2,724,674	$2,853,054	$4,255,794	$1,850,046	$17,007,491
169												
170			Weighted Average Hedged Cost per Unit			$4.7810	$5.1667	$5.2398	$5.0947	$4.9486	$4.8685	$5.0170
171												
172								**THIS PAGE HAS BEEN REDACTED**				

00000050

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line	For Month of:	Reference		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
173	NYMEX Settlement - 15 Day Average									
174		Days	Date							
175		1	01-Aug	4.3030	4.5050	4.6070	4.6080	4.5750	4.5120	
176		2	02-Aug	4.2710	4.4780	4.5760	4.5780	4.5480	4.4890	
177		3	03-Aug	4.2220	4.4250	4.5240	4.5280	4.4990	4.4430	
178		4	04-Aug	4.0900	4.2970	4.3980	4.4030	4.3770	4.3320	
179		5	05-Aug	4.1130	4.3300	4.4320	4.4350	4.4090	4.3690	
180			06-Aug							
181			07-Aug							
182		6	08-Aug	4.1150	4.3400	4.4390	4.4410	4.4140	4.3710	
183		7	09-Aug	4.1670	4.3880	4.4850	4.4860	4.4580	4.4130	
184		8	10-Aug	4.1810	4.4020	4.4970	4.4970	4.4670	4.4180	
185		9	11-Aug	4.2790	4.4970	4.5860	4.5840	4.5450	4.4930	
186		10	12-Aug	4.2190	4.4410	4.5290	4.5310	4.4950	4.4500	
187			13-Aug							
188			14-Aug							
189		11	15-Aug	4.1840	4.4110	4.5050	4.5080	4.4740	4.4320	
190		12	16-Aug	4.0900	4.3220	4.4250	4.4260	4.4000	4.3710	
191		13	17-Aug	4.0840	4.3130	4.4170	4.4170	4.3890	4.3600	
192		14	18-Aug	4.0380	4.2710	4.3770	4.3790	4.3490	4.3220	
193		15	19-Aug	4.0750	4.3070	4.4120	4.4120	4.3780	4.3440	
194			20-Aug							
195			21-Aug							
196			22-Aug							
197			23-Aug							
198			24-Aug							
199			25-Aug							
200										
201			15 Day Average	4.1621	4.3818	4.4806	4.4822	4.4518	4.4079	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Residential Heating Rate R-3

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**

Residential Heating (R3)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	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
	07/01/2011	04/01/2011															
Winter:																	
Cust. Chg	$17.33	$17.16	$17.33	$17.33	$17.33	$17.33	$17.33	$17.33	$103.98								
Headblock	$0.2741	$0.2714	$27.41	$27.41	$27.41	$27.41	$27.41	$27.41	$164.46								
Tailblock	$0.2265	$0.2243	$2.04	$11.33	$19.71	$19.93	$14.95	$7.25	$75.20								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$17.33	$17.16								$17.16	$17.16	$17.33	$17.33	$17.33	$17.33	$103.64	$207.62
Headblock	$0.2741	$0.2714								$5.43	$5.43	$5.48	$5.48	$5.48	$5.48	$32.78	$197.24
Tailblock	$0.2265	$0.2243								$15.70	$7.85	$2.27	$2.27	$4.98	$11.55	$44.62	$119.81
HB Threshold	20	20															
Total Base Rate Amount			$46.78	$56.07	$64.45	$64.67	$59.69	$51.99	$343.64	$38.29	$30.44	$25.08	$25.08	$27.80	$34.36	$181.04	$524.68
CGA Rate - (Seasonal)			$0.7926	$0.7926	$0.7926	$0.7926	$0.7926	$0.7926	$0.7926	$0.7326	$0.7429	$0.7612	$0.7884	$0.7581	$0.7581	$0.7514	$0.7821
CGA amount			$86.39	$118.89	$148.22	$149.01	$131.57	$104.62	$738.70	$65.93	$40.86	$22.84	$23.65	$31.84	$53.83	$238.95	$977.65
LDAC			$0.0697	$0.0697	$0.0697	$0.0697	$0.0697	$0.0697	0.0697	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0696
LDAC amount			$7.60	$10.46	$13.03	$13.10	$11.57	$9.20	$64.96	$6.24	$3.81	$2.08	$2.08	$2.91	$4.92	$22.04	$87.00
Total Bill			**$140.77**	**$185.41**	**$225.70**	**$226.78**	**$202.83**	**$165.81**	**$1,147.30**	**$110.46**	**$75.11**	**$49.99**	**$50.81**	**$62.55**	**$93.11**	**$442.02**	**$1,589.33**

Residential Heating (R3)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	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:	07/01/2010	06/01/2010															
Cust. Chg	$15.78		$15.78	$15.78	$15.78	$15.78	$15.78	$17.16	$96.06								
Headblock	$0.2774		27.74	27.74	27.74	27.74	27.74	27.14	$165.84								
Tailblock	$0.2091		$1.88	$10.46	$18.19	$18.40	$13.80	$7.18	$69.91								
HB Threshold	100																
Summer:																	
Cust. Chg	$15.78	$15.62								$14.03	$15.62	$15.78	$15.78	$15.78	$15.78	$92.77	$188.83
Headblock	$0.2774	$0.2747								$4.93	$5.49	$5.55	$5.55	$5.55	$5.55	$32.62	$198.46
Tailblock	$0.2091	$0.2070								$13.01	$7.25	$2.09	$2.09	$4.60	$10.66	$39.70	$109.61
HB Threshold	20	20															
Total Base Rate Amount			$45.40	$53.98	$61.71	$61.92	$57.32	$51.48	$331.81	$31.98	$28.36	$23.42	$23.42	$25.93	$31.99	$165.09	$496.90
		08/01/2009															
CGA Rate - (Seasonal)		$14.03	$0.8220	$0.7659	$0.7890	$0.8098	$0.8348	$0.7990	$0.8029	$0.7209	$0.7125	$0.7937	$0.7302	$0.7545	$0.7084	$0.7288	$0.7841
CGA amount		$0.2467	$89.60	$114.88	$147.54	$152.24	$138.57	$105.47	$748.29	$64.88	$39.19	$23.81	$21.91	$31.69	$50.30	$231.77	$980.07
		$0.1859															
LDAC		20	$0.0641	$0.0641	$0.0641	$0.0641	$0.0641	$0.0641	0.0641	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0581
LDAC amount			$6.99	$9.62	$11.99	$12.05	$10.64	$8.46	$59.74	$3.64	$2.22	$1.21	$1.21	$1.70	$2.87	$12.85	$72.59
Total Bill			**$141.99**	**$178.47**	**$221.24**	**$226.21**	**$206.53**	**$165.41**	**$1,139.84**	**$100.49**	**$69.77**	**$48.44**	**$46.54**	**$59.31**	**$85.16**	**$409.71**	**$1,549.56**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	Jun	Jul	Aug	Sep	Oct	Summer	Total
Total Bill	**($1.22)**	**$6.94**	**$4.46**	**$0.58**	**($3.70)**	**$0.41**	**$7.46**	**$9.97**	**$5.34**	**$1.55**	**$4.27**	**$3.23**	**$7.95**	**$32.31**	**$39.77**
% Change	**-0.86%**	**3.89%**	**2.02%**	**0.25%**	**-1.79%**	**0.24%**	**0.65%**	**9.92%**	**7.66%**	**3.20%**	**9.18%**	**5.45%**	**9.34%**	**7.89%**	**2.57%**
Base Rate	$1.38	$2.09	$2.73	$2.75	$2.37	$0.51	$11.83	$6.31	$2.08	$1.66	$1.66	$1.87	$2.37	$15.95	$27.78
% Change	3.03%	3.87%	4.43%	4.44%	4.13%	0.99%	3.57%	19.74%	7.33%	7.08%	7.08%	7.20%	7.41%	9.66%	5.59%
CGA & LDAC	($2.59)	$4.85	$1.73	($2.18)	($6.07)	($0.11)	($4.37)	$3.65	$3.26	($0.11)	$2.61	$1.37	$5.58	$16.37	$12.00
% Change	-2.90%	4.22%	1.17%	-1.43%	-4.38%	-0.10%	-0.58%	5.63%	8.32%	-0.45%	11.93%	4.31%	11.10%	7.06%	1.22%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Commercial Rate G-41

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Commercial Rate (G-41)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	07/01/2011	04/01/2011															
Cust. Chg	$40.77	$40.37	$40.77	$40.77	$40.77	$40.77	$40.77	$40.77	$244.62								
Headblock	$0.3254	$0.3222	$32.54	$32.54	$32.54	$32.54	$32.54	$32.54	$195.24								
Tailblock	$0.2116	$0.2095	$19.68	$35.76	$41.90	$34.28	$28.35	$15.02	$174.99								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$40.77	$40.37								$40.37	$40.37	$40.77	$40.77	$40.77	$40.77	$243.82	$488.44
Headblock	$0.3254	$0.3222								$6.44	$6.44	$6.51	$6.51	$6.51	$6.51	$38.92	$234.16
Tailblock	$0.2116	$0.2095								$20.32	$12.78	$11.00	$11.00	$14.60	$25.82	$95.52	$270.52
HB Threshold	20	20															
Total Base Rate Amount			$92.99	$109.07	$115.21	$107.59	$101.66	$88.33	$614.85	$67.14	$59.59	$58.28	$58.28	$61.88	$73.09	$378.26	$993.12
CGA Rate - (Seasonal)			$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7365	$0.7468	$0.7651	$0.7923	$0.7620	$0.7620	$0.7588	$0.7831
CGA amount			$153.03	$213.29	$236.28	$207.74	$185.54	$135.59	$1,131.47	$86.17	$60.49	$55.09	$57.05	$67.82	$108.20	$434.82	$1,566.28
LDAC			$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	0.0497	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0490
LDAC amount			$9.59	$13.37	$14.81	$13.02	$11.63	$8.50	$70.93	$5.55	$3.84	$3.41	$3.41	$4.22	$6.73	$27.16	$98.09
Total Bill			**$255.61**	**$335.73**	**$366.30**	**$328.35**	**$298.83**	**$232.42**	**$1,817.25**	**$158.85**	**$123.92**	**$116.78**	**$118.74**	**$133.92**	**$188.03**	**$840.24**	**$2,657.49**

November 1, 2011 - April 30, 2012
Commercial Rate (G-41)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	07/01/2010	06/01/2010															
Cust. Chg	$39.45		$39.45	$39.45	$39.45	$39.45	$39.45	$40.37	$237.62								
Headblock	$0.3344		33.44	33.44	33.44	33.44	33.44	32.22	$199.42								
Tailblock	$0.2175		$20.23	$36.76	$43.07	$35.24	$29.15	$14.87	$179.30								
HB Threshold	100																
Summer:																	
Cust. Chg	$39.45	$39.07								$35.08	$39.07	$39.45	$39.45	$39.45	$39.45	$231.95	$469.57
Headblock	$0.3344	$0.3312								$6.78	$6.62	$6.69	$6.69	$6.69	$6.69	$40.16	$239.58
Tailblock	$0.2175	$0.2154								$18.76	$13.14	$11.31	$11.31	$15.01	$26.54	$96.06	$275.37
HB Threshold	20	20															
Total Base Rate Amount			$93.12	$109.65	$115.96	$108.13	$102.04	$87.46	$616.34	$60.62	$58.83	$57.45	$57.45	$61.15	$72.67	$368.17	$984.52
		08/01/2009															
CGA Rate - (Seasonal)		$35.08	$0.8234	$0.7673	$0.7904	$0.8112	$0.8362	$0.8004	$0.8030	$0.7212	$0.7128	$0.7940	$0.7305	$0.7548	$0.7087	$0.7324	$0.7828
CGA amount		$0.2974	$158.92	$206.40	$235.53	$212.53	$195.66	$136.87	$1,145.90	$84.38	$57.74	$57.17	$52.60	$67.18	$100.64	$419.69	$1,565.60
		$0.1934															
LDAC		20	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0357
LDAC amount			$8.14	$11.35	$12.58	$11.06	$9.87	$7.22	$60.22	$2.27	$1.57	$1.40	$1.40	$1.73	$2.75	$11.12	$71.34
Total Bill			**$260.18**	**$327.40**	**$364.06**	**$331.71**	**$307.57**	**$231.55**	**$1,822.47**	**$147.27**	**$118.14**	**$116.01**	**$111.44**	**$130.05**	**$176.06**	**$798.98**	**$2,621.45**

DIFFERENCE:

Total Bill	**($4.57)**	**$8.33**	**$2.24**	**($3.36)**	**($8.74)**	**$0.87**	**($5.22)**	**$11.58**	**$5.78**	**$0.77**	**$7.30**	**$3.87**	**$11.96**	**$41.26**	**$36.04**
% Change	**-1.76%**	**2.55%**	**0.62%**	**-1.01%**	**-2.84%**	**0.38%**	**-0.29%**	**7.86%**	**4.89%**	**0.66%**	**6.55%**	**2.97%**	**6.80%**	**5.16%**	**1.37%**
Base Rate	($0.13)	($0.58)	($0.75)	($0.54)	($0.37)	$0.87	($1.49)	$6.51	$0.76	$0.83	$0.83	$0.73	$0.42	$10.09	$8.60
% Change	-0.14%	-0.53%	-0.65%	-0.50%	-0.36%	0.99%	-0.24%	10.74%	1.29%	1.45%	1.45%	1.20%	0.58%	2.74%	0.87%
CGA & LDAC	($4.44)	$8.91	$2.99	($2.82)	($8.37)	$0.00	($3.73)	$5.07	$5.02	($0.06)	$6.47	$3.13	$11.54	$31.17	$27.44
% Change	-2.79%	4.32%	1.27%	-1.33%	-4.28%	0.00%	-0.33%	6.00%	8.70%	-0.11%	12.29%	4.66%	11.47%	7.43%	1.75%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Commercial Rate G-42

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
C&I High Winter Use Medium G-42

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	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
	07/01/2011	04/01/2011															
Winter:																	
Cust. Chg	$122.32	$121.11	$122.32	$122.32	$122.32	$122.32	$122.32	$122.32	$733.92								
Headblock	$0.3041	$0.3011	$304.10	$304.10	$304.10	$304.10	$304.10	$304.10	$1,824.60								
Tailblock	$0.2009	$0.1989	$111.10	$317.02	$455.04	$623.39	$482.56	$295.93	$2,285.04								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.32	$121.11								$121.11	$121.11	$122.32	$122.32	$122.32	$122.32	$731.50	$1,465.42
Headblock	$0.3041	$0.3011								$120.44	$120.44	$121.64	$64.77	$110.69	$121.64	$659.63	$2,484.23
Tailblock	$0.2009	$0.1989								$170.66	$59.87	$2.81	$0.00	$0.00	$60.07	$293.41	$2,578.44
HB Threshold	400	400															
Total Base Rate Amount			$537.52	$743.44	$881.46	$1,049.81	$908.98	$722.35	$4,843.56	$412.21	$301.42	$246.77	$187.09	$233.01	$304.03	$1,684.53	$6,528.09
CGA Rate - (Seasonal)			$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7365	$0.7468	$0.7651	$0.7923	$0.7620	$0.7620	$0.7524	$0.7859
CGA amount			$1,231.37	$2,044.10	$2,588.82	$3,253.27	$2,697.45	$1,960.84	$13,775.84	$926.52	$523.51	$316.75	$168.76	$277.37	$532.64	$2,745.54	$16,521.39
LDAC			$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	0.0497	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0493
LDAC amount			$77.19	$128.13	$162.28	$203.93	$169.09	$122.91	$863.53	$59.63	$33.23	$19.62	$10.10	$17.25	$33.13	$172.96	$1,036.49
Total Bill			**$1,846.08**	**$2,915.67**	**$3,632.56**	**$4,507.01**	**$3,775.52**	**$2,806.10**	**$19,482.93**	**$1,398.35**	**$858.15**	**$583.15**	**$365.95**	**$527.63**	**$869.80**	**$4,603.04**	**$24,085.97**

November 1, 2011 - April 30, 2012
C&I High Winter Use Medium G-42

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	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
	07/01/2010	06/01/2010															
Winter:																	
Cust. Chg	$112.73		$112.73	$112.73	$112.73	$112.73	$112.73	$121.11	$684.76								
Headblock	$0.2971		297.10	297.10	297.10	297.10	297.10	301.10	$1,786.60								
Tailblock	$0.1962		$108.50	$309.60	$444.39	$608.81	$471.27	$292.98	$2,235.56								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$112.73	$111.63								$100.24	$111.63	$112.73	$112.73	$112.73	$112.73	$662.79	$1,347.55
Headblock	$0.2971	$0.2942								$105.68	$117.68	$118.84	$63.28	$108.14	$118.84	$632.47	$2,419.07
Tailblock	$0.1962	$0.1943								$149.72	$58.48	$2.75	$0.00	$0.00	$58.66	$269.62	$2,505.17
HB Threshold	400	400															
Total Base Rate Amount			$518.33	$719.43	$854.22	$1,018.64	$881.10	$715.19	$4,706.92	$355.64	$287.79	$234.32	$176.01	$220.87	$290.23	$1,564.87	$6,271.79
		08/01/2009															
CGA Rate - (Seasonal)		$100.24	$0.8234	$0.7673	$0.7904	$0.8112	$0.8362	$0.8004	$0.8052	$0.7212	$0.7128	$0.7940	$0.7305	$0.7548	$0.7087	$0.7293	$0.7920
CGA amount		$0.2642	$1,278.74	$1,978.05	$2,580.58	$3,328.25	$2,844.61	$1,979.39	$13,989.62	$907.27	$499.67	$328.72	$155.60	$274.75	$495.38	$2,661.38	$16,651.00
		$0.1745															
LDAC		400	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0382
LDAC amount			$65.54	$108.79	$137.78	$173.15	$143.56	$104.36	$733.18	$24.41	$13.60	$8.03	$4.13	$7.06	$13.56	$70.79	$803.97
Total Bill			**$1,862.61**	**$2,806.28**	**$3,572.59**	**$4,520.03**	**$3,869.27**	**$2,798.94**	**$19,429.72**	**$1,287.32**	**$801.07**	**$571.06**	**$335.74**	**$502.68**	**$799.18**	**$4,297.05**	**$23,726.76**
DIFFERENCE:																	
Total Bill			**($16.53)**	**$109.39**	**$59.97**	**($13.02)**	**($93.76)**	**$7.16**	**$53.21**	**$111.04**	**$57.09**	**$12.08**	**$30.21**	**$24.95**	**$70.62**	**$305.99**	**$359.20**
% Change			**-0.89%**	**3.90%**	**1.68%**	**-0.29%**	**-2.42%**	**0.26%**	**0.27%**	**8.63%**	**7.13%**	**2.12%**	**9.00%**	**4.96%**	**8.84%**	**7.12%**	**1.51%**
Base Rate			$19.19	$24.01	$27.24	$31.17	$27.88	$7.16	$136.64	$56.57	$13.62	$12.46	$11.08	$12.14	$13.80	$119.66	$256.30
% Change			3.70%	3.34%	3.19%	3.06%	3.16%	1.00%	2.90%	15.91%	4.73%	5.32%	6.30%	5.50%	4.75%	7.65%	4.09%
CGA & LDAC			($35.72)	$85.38	$32.73	($44.20)	($121.64)	$0.01	($83.43)	$54.47	$43.46	($0.37)	$19.13	$12.81	$56.83	$186.33	$102.90
% Change			-2.79%	4.32%	1.27%	-1.33%	-4.28%	0.00%	-0.60%	6.00%	8.70%	-0.11%	12.29%	4.66%	11.47%	7.00%	0.62%
check			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Commercial Rate G-52

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Commercial Rate (G-52)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	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:	07/01/2011	04/01/2011															
Cust. Chg	$122.32	$121.11	$122.32	$122.32	$122.32	$122.32	$122.32	$122.32	$733.92								
Headblock	$0.1684	$0.1667	$168.40	$168.40	$168.40	$168.40	$168.40	$168.40	$1,010.40								
Tailblock	$0.1143	$0.1131	$82.52	$124.13	$152.02	$152.36	$147.56	$99.67	$758.27								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.32	$121.11								$121.11	$121.11	$122.32	$122.32	$122.32	$122.32	$731.50	$1,465.42
Headblock	$0.1237	$0.1225								$122.50	$122.50	$123.70	$123.70	$123.70	$123.70	$739.80	$1,750.20
Tailblock	$0.0713	$0.0705								$35.96	$26.37	$17.61	$13.55	$14.97	$23.10	$131.55	$889.82
HB Threshold	1,000	1,000															
Total Base Rate Amount			$373.24	$414.85	$442.74	$443.08	$438.28	$390.39	$2,502.59	$279.57	$269.98	$263.63	$259.57	$260.99	$269.12	$1,602.85	$4,105.44
CGA Rate - (Seasonal)			$0.7911	$0.7911	$0.7911	$0.7911	$0.7911	$0.7911	$0.7911	$0.7256	$0.7359	$0.7542	$0.7814	$0.7511	$0.7511	$0.7486	$0.7748
CGA amount			$1,362.27	$1,650.23	$1,843.26	$1,845.64	$1,812.41	$1,480.94	$9,994.76	$1,095.66	$1,011.13	$940.49	$929.87	$908.83	$994.46	$5,880.42	$15,875.18
LDAC			$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	0.0497	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0488
LDAC amount			$85.59	$103.68	$115.81	$115.96	$113.87	$93.04	$627.94	$71.57	$65.13	$59.11	$56.41	$57.35	$62.76	$372.33	$1,000.27
Total Bill			**$1,821.11**	**$2,168.76**	**$2,401.81**	**$2,404.67**	**$2,364.56**	**$1,964.37**	**$13,125.29**	**$1,446.80**	**$1,346.23**	**$1,263.23**	**$1,245.84**	**$1,227.18**	**$1,326.34**	**$7,855.60**	**$20,980.89**

November 1, 2011 - April 30, 2012
Commercial Rate (G-52)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	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:	07/01/2010	06/01/2010															
Cust. Chg	$112.73		$112.73	$112.73	$112.73	$112.73	$112.73	$121.11	$684.76								
Headblock	$0.1692		169.20	169.20	169.20	169.20	169.20	166.70	$1,012.70								
Tailblock	$0.1148		$82.89	$124.67	$152.68	$153.03	$148.21	$98.62	$760.10								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$112.73	$111.63								$100.24	$111.63	$112.73	$112.73	$112.73	$112.73	$662.79	$1,347.55
Headblock	$0.1244	$0.1232								$110.60	$123.20	$124.40	$124.40	$124.40	$124.40	$731.40	$1,744.10
Tailblock	$0.0716	$0.0709								$32.49	$26.52	$17.69	$13.60	$15.04	$23.20	$128.53	$888.63
HB Threshold	1,000	1,000															
Total Base Rate Amount			$364.82	$406.60	$434.61	$434.96	$430.14	$386.43	$2,457.56	$243.33	$261.35	$254.82	$250.73	$252.17	$260.33	$1,522.72	$3,980.28
		08/01/2009															
CGA Rate - (Seasonal)		$100.24	$0.8186	$0.7625	$0.7856	$0.8064	$0.8314	$0.7956	$0.7999	$0.7202	$0.7118	$0.7930	$0.7295	$0.7538	$0.7077	$0.7348	$0.7749
CGA amount		$0.1106	$1,409.63	$1,590.54	$1,830.40	$1,881.27	$1,904.64	$1,489.36	$10,105.84	$1,087.50	$978.01	$988.87	$868.11	$912.10	$936.99	$5,771.58	$15,877.42
		$0.0637															
LDAC		1,000	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0335
LDAC amount			$72.67	$88.03	$98.33	$98.45	$96.68	$79.00	$533.15	$29.29	$26.66	$24.19	$23.09	$23.47	$25.69	$152.39	$685.54
Total Bill			**$1,847.11**	**$2,085.17**	**$2,363.34**	**$2,414.68**	**$2,431.46**	**$1,954.79**	**$13,096.55**	**$1,360.12**	**$1,266.02**	**$1,267.88**	**$1,141.93**	**$1,187.74**	**$1,223.01**	**$7,446.69**	**$20,543.24**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($26.01)**	**$83.59**	**$38.47**	**($10.01)**	**($66.90)**	**$9.58**	**$28.73**	**$86.67**	**$80.22**	**($4.65)**	**$103.91**	**$39.44**	**$103.33**	**$408.92**	**$437.65**
% Change	**-1.41%**	**4.01%**	**1.63%**	**-0.41%**	**-2.75%**	**0.49%**	**0.22%**	**6.37%**	**6.34%**	**-0.37%**	**9.10%**	**3.32%**	**8.45%**	**5.49%**	**2.13%**
Base Rate	$8.43	$8.25	$8.13	$8.12	$8.14	$3.96	$45.03	$36.24	$8.63	$8.82	$8.83	$8.83	$8.79	$80.14	$125.16
% Change	2.31%	2.03%	1.87%	1.87%	1.89%	1.02%	1.83%	14.89%	3.30%	3.46%	3.52%	3.50%	3.38%	5.26%	3.14%
CGA & LDAC	($34.44)	$75.35	$30.35	($18.13)	($75.04)	$5.62	($16.29)	$50.43	$71.59	($13.47)	$95.08	$30.61	$94.53	$328.78	$312.49
% Change	-2.44%	4.74%	1.66%	-0.96%	-3.94%	0.38%	-0.16%	4.64%	7.32%	-1.36%	10.95%	3.36%	10.09%	5.70%	1.97%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Residential Heating

	Winter 2010-11	Winter 2011-12
Customer Charge	$15.78	$17.33
First 100 Therms	$0.2774	$0.2741
Excess 100 Therms	$0.2091	$0.2265
LDAC	$0.0641	$0.0697
CGA	$0.8029	$0.7926
Total Adjust	$0.8670	$0.8623

		Winter 2010-11 CGA @	Winter 2011-12 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.8670	$0.8623	($0.00)	-1%						
Cooking alone	5	$21.50	$23.01	$1.51	7%	$1.53	7%	-$0.05	0%	$0.03	0%
	10	$27.22	$28.69	$1.47	5%	$1.52	6%	-$0.10	0%	$0.06	0%
	20	$38.67	$40.06	$1.39	4%	$1.48	4%	-$0.21	-1%	$0.11	0%
Water Heating alone	30	$50.11	$51.42	$1.31	3%	$1.45	3%	-$0.31	-1%	$0.17	0%
	45	$67.28	$68.47	$1.19	2%	$1.40	2%	-$0.46	-1%	$0.25	0%
	50	$73.00	$74.15	$1.15	2%	$1.39	2%	-$0.51	-1%	$0.28	0%
Heating Alone	80	$101.61	$102.56	$0.95	1%	$1.30	1%	-$0.77	-1%	$0.42	0%
	125	$165.73	$166.90	$1.17	1%	$1.79	1%	-$1.37	-1%	$0.75	0%
	150	$184.02	$185.41	$1.39	1%	$2.09	1%	-$1.54	-1%	$0.84	0%
	200	$237.83	$239.85	$2.02	1%	$2.96	1%	-$2.06	-1%	$1.12	0%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Residential Heating Rate R-3

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Residential Heating (R3)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			55	92	144	148	123	80	641	53	29	18	15	16	24	156	796
	07/01/2011	04/01/2011															
Winter:																	
Cust. Chg	$17.33	$17.16	$17.33	$17.33	$17.33	$17.33	$17.33	$17.33	$103.98								
Headblock	$0.2741	$0.2714	$14.94	$25.27	$27.41	$27.41	$27.41	$21.92	$144.36								
Tailblock	$0.2265	$0.2243	$0.00	$0.00	$9.90	$10.76	$5.17	$0.00	$25.83								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$17.33	$17.16								$17.16	$17.16	$17.33	$17.33	$17.33	$17.33	$103.64	$207.62
Headblock	$0.2741	$0.2714								$5.43	$5.43	$4.84	$4.21	$4.46	$5.48	$29.85	$174.21
Tailblock	$0.2265	$0.2243								$7.51	$2.07	$0.00	$0.00	$0.00	$0.80	$10.38	$36.21
HB Threshold	20	20															
Total Base Rate Amount			$32.27	$42.60	$54.64	$55.50	$49.91	$39.25	$274.17	$30.10	$24.66	$22.17	$21.54	$21.79	$23.61	$143.87	$418.04
CGA Rate - (Seasonal)			$0.7926	$0.7926	$0.7926	$0.7926	$0.7926	$0.7926	$0.7926	$0.7326	$0.7429	$0.7612	$0.7884	$0.7581	$0.7581	$0.7498	$0.7842
CGA amount			$43.21	$73.07	$113.89	$116.91	$97.35	$63.39	$507.82	$39.18	$21.72	$13.45	$12.11	$12.33	$17.83	$116.63	$624.44
LDAC			$0.0697	$0.0697	$0.0697	$0.0697	$0.0697	$0.0697	0.0697	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0696
LDAC amount			$3.80	$6.43	$10.02	$10.28	$8.56	$5.57	$44.66	$3.71	$2.03	$1.22	$1.06	$1.13	$1.63	$10.78	$55.44
Total Bill			**$79.28**	**$122.10**	**$178.54**	**$182.70**	**$155.82**	**$108.21**	**$826.64**	**$72.99**	**$48.41**	**$36.84**	**$34.72**	**$35.25**	**$43.07**	**$271.28**	**$1,097.92**

Residential Heating (R3)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			55	92	144	148	123	80	641	90	55	30	30	42	71	156	796
Winter:	07/01/2010	06/01/2010															
Cust. Chg	$15.78		$15.78	$15.78	$15.78	$15.78	$15.78	$17.16	$96.06								
Headblock	$0.2774		15.12	25.57	27.74	27.74	27.74	21.70	$145.62								
Tailblock	$0.2091		$0.00	$0.00	$9.14	$9.93	$4.77	$0.00	$23.84								
HB Threshold	100																
Summer:																	
Cust. Chg	$15.78	$15.62								$14.03	$15.62	$15.78	$15.78	$15.78	$15.78	$92.77	$188.83
Headblock	$0.2774	$0.2747								$4.93	$5.49	$5.55	$5.55	$5.55	$5.55	$32.62	$178.24
Tailblock	$0.2091	$0.2070								$13.01	$7.25	$2.09	$2.09	$4.60	$10.66	$39.70	$63.55
HB Threshold	20	20															
Total Base Rate Amount			$30.90	$41.35	$52.66	$53.45	$48.29	$38.86	$265.52	$31.98	$28.36	$23.42	$23.42	$25.93	$31.99	$165.09	$430.62
		08/01/2009															
CGA Rate - (Seasonal)		$14.03	$0.8220	$0.7659	$0.7890	$0.8098	$0.8348	$0.7990	$0.8033	$0.7209	$0.7125	$0.7937	$0.7302	$0.7545	$0.7084	$1.4901	$0.9374
CGA amount		$0.2467	$44.81	$70.61	$113.37	$119.45	$102.53	$63.90	$514.66	$64.88	$39.19	$23.81	$21.91	$31.69	$50.30	$231.77	$746.43
		$0.1859															
LDAC		20	$0.0641	$0.0641	$0.0641	$0.0641	$0.0641	$0.0641	0.0641	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0826	$0.0677
LDAC amount			$3.49	$5.91	$9.21	$9.46	$7.87	$5.13	$41.07	$3.64	$2.22	$1.21	$1.21	$1.70	$2.87	$12.85	$53.92
Total Bill			**$79.21**	**$117.87**	**$175.23**	**$182.36**	**$158.69**	**$107.89**	**$821.25**	**$100.49**	**$69.77**	**$48.44**	**$46.54**	**$59.31**	**$85.16**	**$409.71**	**$1,230.96**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$0.07**	**$4.23**	**$3.31**	**$0.34**	**($2.87)**	**$0.32**	**$5.39**	**($27.51)**	**($21.36)**	**($11.60)**	**($11.82)**	**($24.07)**	**($42.08)**	**($138.43)**	**($133.04)**
% Change	**0.09%**	**3.58%**	**1.89%**	**0.19%**	**-1.81%**	**0.30%**	**0.66%**	**-27.37%**	**-30.62%**	**-23.94%**	**-25.39%**	**-40.57%**	**-49.42%**	**-33.79%**	**-10.81%**
Base Rate	$1.37	$1.25	$1.98	$2.05	$1.62	$0.39	$8.65	($1.88)	($3.70)	($1.25)	($1.88)	($4.14)	($8.38)	($21.22)	($12.58)
% Change	4.43%	3.01%	3.76%	3.83%	3.35%	0.99%	3.26%	-5.87%	-13.04%	-5.32%	-8.02%	-15.96%	-26.20%	-12.86%	-2.92%
CGA & LDAC	($1.30)	$2.98	$1.33	($1.71)	($4.49)	($0.06)	($3.25)	($25.63)	($17.66)	($10.35)	($9.94)	($19.93)	($33.70)	($117.21)	($120.46)
% Change	-2.90%	4.22%	1.17%	-1.43%	-4.38%	-0.10%	-0.63%	-39.50%	-45.07%	-43.47%	-45.37%	-62.88%	-67.01%	-50.57%	-16.14%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Commercial Rate G-41

November 1, 2011 - April 30, 2012 | **May 1, 2011 - October 31, 2011**
Commercial Rate (G-41)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			142	265	466	480	398	241	1,992	142	68	36	31	34	52	363	2,355
Winter:	07/01/2011	04/01/2011															
Cust. Chg	$40.77	$40.37	$40.77	$40.77	$40.77	$40.77	$40.77	$40.77	$244.62								
Headblock	$0.3254	$0.3222	$32.54	$32.54	$32.54	$32.54	$32.54	$32.54	$195.24								
Tailblock	$0.2116	$0.2095	$8.94	$35.00	$77.45	$80.36	$62.96	$29.91	$294.62								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$40.77	$40.37								$40.37	$40.37	$40.77	$40.77	$40.77	$40.77	$243.82	$488.44
Headblock	$0.3254	$0.3222								$6.44	$6.44	$6.51	$6.51	$6.51	$6.51	$38.92	$234.16
Tailblock	$0.2116	$0.2095								$25.61	$10.04	$3.37	$2.29	$2.91	$6.76	$50.98	$345.60
HB Threshold	20	20															
Total Base Rate Amount			$82.25	$108.31	$150.76	$153.67	$136.27	$103.22	$734.48	$72.43	$56.86	$50.65	$49.56	$50.18	$54.04	$333.72	$1,068.20
CGA Rate - (Seasonal)			$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7365	$0.7468	$0.7651	$0.7923	$0.7620	$0.7620	$0.7520	$0.7866
CGA amount			$112.79	$210.45	$369.50	$380.43	$315.20	$191.37	$1,579.74	$104.77	$50.73	$27.49	$24.40	$25.70	$39.59	$272.70	$1,852.43
LDAC			$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	0.0497	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0493
LDAC amount			$7.07	$13.19	$23.16	$23.85	$19.76	$12.00	$99.03	$6.74	$3.22	$1.70	$1.46	$1.60	$2.46	$17.19	$116.21
Total Bill			**$202.10**	**$331.96**	**$543.42**	**$557.95**	**$471.22**	**$306.59**	**$2,413.24**	**$183.93**	**$110.81**	**$79.85**	**$75.43**	**$77.49**	**$96.10**	**$623.60**	**$3,036.85**

November 1, 2011 - April 30, 2012
Commercial Rate (G-41)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			142	265	466	480	398	241	1,992	142	68	36	31	34	52	363	2,355
Winter:	07/01/2010	06/01/2010															
Cust. Chg	$39.45		$39.45	$39.45	$39.45	$39.45	$39.45	$40.37	$237.62								
Headblock	$0.3344		33.44	33.44	33.44	33.44	33.44	32.22	$199.42								
Tailblock	$0.2175		$9.19	$35.98	$79.61	$82.60	$64.71	$29.61	$301.71								
HB Threshold	100																
Summer:																	
Cust. Chg	$39.45	$39.07								$35.08	$39.07	$39.45	$39.45	$39.45	$39.45	$231.95	$469.57
Headblock	$0.3344	$0.3312								$6.78	$6.62	$6.69	$6.69	$6.69	$6.69	$40.16	$239.58
Tailblock	$0.2175	$0.2154								$23.64	$10.32	$3.47	$2.35	$2.99	$6.95	$49.72	$351.43
HB Threshold	20	20															
Total Base Rate Amount			$82.08	$108.87	$152.50	$155.49	$137.60	$102.20	$738.75	$65.51	$56.02	$49.60	$48.49	$49.12	$53.09	$321.83	$1,060.58
		08/01/2009															
CGA Rate - (Seasonal)		$35.08	$0.8234	$0.7673	$0.7904	$0.8112	$0.8362	$0.8004	$0.8050	$0.7212	$0.7128	$0.7940	$0.7305	$0.7548	$0.7087	$0.7290	$0.7933
CGA amount		$0.2974	$117.12	$203.65	$368.32	$389.19	$332.39	$193.18	$1,603.87	$102.59	$48.42	$28.53	$22.50	$25.46	$36.82	$264.33	$1,868.21
		$0.1934															
LDAC		20	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0387
LDAC amount			$6.00	$11.20	$19.67	$20.25	$16.78	$10.19	$84.08	$2.76	$1.32	$0.70	$0.60	$0.65	$1.01	$7.03	$91.11
Total Bill			**$205.21**	**$323.72**	**$540.49**	**$564.94**	**$486.77**	**$305.57**	**$2,426.70**	**$170.86**	**$105.76**	**$78.83**	**$71.59**	**$75.24**	**$90.92**	**$593.20**	**$3,019.90**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($3.10)**	**$8.23**	**$2.93**	**($6.99)**	**($15.55)**	**$1.02**	**($13.45)**	**$13.08**	**$5.05**	**$1.01**	**$3.84**	**$2.25**	**$5.18**	**$30.40**	**$16.95**
% Change	**-1.51%**	**2.54%**	**0.54%**	**-1.24%**	**-3.19%**	**0.33%**	**-0.55%**	**7.65%**	**4.77%**	**1.29%**	**5.37%**	**2.99%**	**5.69%**	**5.13%**	**0.56%**
Base Rate	$0.17	($0.56)	($1.74)	($1.82)	($1.34)	$1.02	($4.26)	$6.92	$0.84	$1.05	$1.08	$1.06	$0.95	$11.89	$7.62
% Change	0.21%	-0.51%	-1.14%	-1.17%	-0.97%	0.99%	-0.58%	10.56%	1.49%	2.11%	2.22%	2.16%	1.79%	3.69%	0.72%
CGA & LDAC	($3.27)	$8.79	$4.67	($5.17)	($14.21)	$0.00	($9.19)	$6.16	$4.21	($0.03)	$2.77	$1.19	$4.22	$18.52	$9.33
% Change	-2.79%	4.32%	1.27%	-1.33%	-4.28%	0.00%	-0.57%	6.00%	8.70%	-0.11%	12.29%	4.66%	11.47%	7.01%	0.50%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Commercial Rate G-42

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
C&I High Winter Use Medium G-42

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,330	2,185	3,517	3,614	3,148	2,198	15,992	1,386	725	342	389	367	591	3,802	19,794
	07/01/2011	04/01/2011															
Winter:																	
Cust. Chg	$122.32	$121.11	$122.32	$122.32	$122.32	$122.32	$122.32	$122.32	$733.92								
Headblock	$0.3041	$0.3011	$304.10	$304.10	$304.10	$304.10	$304.10	$304.10	$1,824.60								
Tailblock	$0.2009	$0.1989	$66.37	$238.11	$505.67	$525.16	$431.51	$240.67	$2,007.49								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.32	$121.11								$121.11	$121.11	$122.32	$122.32	$122.32	$122.32	$731.50	$1,465.42
Headblock	$0.3041	$0.3011								$120.44	$120.44	$104.15	$118.29	$111.52	$121.64	$696.48	$2,521.08
Tailblock	$0.2009	$0.1989								$196.19	$64.74	$0.00	$0.00	$0.00	$38.47	$299.40	$2,306.89
HB Threshold	400	400															
Total Base Rate Amount			$492.79	$664.53	$932.09	$951.58	$857.93	$667.09	$4,566.01	$437.74	$306.29	$226.47	$240.61	$233.84	$282.43	$1,727.38	$6,293.39
CGA Rate - (Seasonal)			$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7929	$0.7365	$0.7468	$0.7651	$0.7923	$0.7620	$0.7620	$0.7532	$0.7853
CGA amount			$1,054.83	$1,732.68	$2,788.64	$2,865.58	$2,495.94	$1,742.78	$12,680.45	$1,021.06	$541.80	$262.03	$308.20	$279.44	$450.71	$2,863.23	$15,543.68
LDAC			$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	0.0497	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0493
LDAC amount			$66.12	$108.61	$174.80	$179.63	$156.46	$109.25	$794.87	$65.71	$34.39	$16.23	$18.44	$17.38	$28.04	$180.19	$975.06
Total Bill			**$1,613.73**	**$2,505.82**	**$3,895.53**	**$3,996.80**	**$3,510.33**	**$2,519.12**	**$18,041.33**	**$1,524.51**	**$882.48**	**$504.72**	**$567.25**	**$530.66**	**$761.18**	**$4,770.80**	**$22,812.13**

November 1, 2011 - April 30, 2012
C&I High Winter Use Medium G-42

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,330	2,185	3,517	3,614	3,148	2,198	15,992	1,386	725	342	389	367	591	3,802	19,794
	07/01/2010	06/01/2010															
Winter:																	
Cust. Chg	$112.73		$112.73	$112.73	$112.73	$112.73	$112.73	$121.11	$684.76								
Headblock	$0.2971		297.10	297.10	297.10	297.10	297.10	301.10	$1,786.60								
Tailblock	$0.1962		$64.81	$232.54	$493.84	$512.88	$421.41	$238.28	$1,963.76								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$112.73	$111.63								$100.24	$111.63	$112.73	$112.73	$112.73	$112.73	$662.79	$1,347.55
Headblock	$0.2971	$0.2942								$105.68	$117.68	$101.75	$115.57	$108.95	$118.84	$668.47	$2,455.07
Tailblock	$0.1962	$0.1943								$172.12	$63.24	$0.00	$0.00	$0.00	$37.57	$272.93	$2,236.70
HB Threshold	400	400															
Total Base Rate Amount			$474.64	$642.37	$903.67	$922.71	$831.24	$660.49	$4,435.12	$378.04	$292.55	$214.48	$228.30	$221.68	$269.14	$1,604.19	$6,039.32
		08/01/2009															
CGA Rate - (Seasonal)		$100.24	$0.8234	$0.7673	$0.7904	$0.8112	$0.8362	$0.8004	$0.8051	$0.7212	$0.7128	$0.7940	$0.7305	$0.7548	$0.7087	$0.7284	$0.7903
CGA amount		$0.2642	$1,095.40	$1,676.70	$2,779.77	$2,931.63	$2,632.11	$1,759.26	$12,874.87	$999.85	$517.13	$271.92	$284.16	$276.80	$419.19	$2,769.05	$15,643.91
		$0.1745															
LDAC		400	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0378
LDAC amount			$56.14	$92.22	$148.42	$152.51	$132.84	$92.75	$674.88	$26.90	$14.07	$6.64	$7.55	$7.11	$11.47	$73.75	$748.63
Total Bill			**$1,626.19**	**$2,411.29**	**$3,831.85**	**$4,006.85**	**$3,596.19**	**$2,512.50**	**$17,984.87**	**$1,404.78**	**$823.76**	**$493.05**	**$520.01**	**$505.59**	**$699.80**	**$4,446.99**	**$22,431.86**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($12.45)**	**$94.54**	**$63.68**	**($10.05)**	**($85.87)**	**$6.61**	**$56.46**	**$119.73**	**$58.72**	**$11.68**	**$47.24**	**$25.07**	**$61.38**	**$323.81**	**$380.27**
% Change	**-0.77%**	**3.92%**	**1.66%**	**-0.25%**	**-2.39%**	**0.26%**	**0.31%**	**8.52%**	**7.13%**	**2.37%**	**9.09%**	**4.96%**	**8.77%**	**7.28%**	**1.70%**
Base Rate	$18.14	$22.16	$28.42	$28.88	$26.68	$6.61	$130.89	$59.70	$13.74	$11.99	$12.31	$12.16	$13.29	$123.18	$254.07
% Change	3.82%	3.45%	3.14%	3.13%	3.21%	1.00%	2.95%	15.79%	4.70%	5.59%	5.39%	5.48%	4.94%	7.68%	4.21%
CGA & LDAC	($30.59)	$72.38	$35.26	($38.93)	($112.55)	$0.01	($74.43)	$60.03	$44.98	($0.31)	$34.93	$12.91	$48.09	$200.63	$126.20
% Change	-2.79%	4.32%	1.27%	-1.33%	-4.28%	0.00%	-0.58%	6.00%	8.70%	-0.11%	12.29%	4.66%	11.47%	7.25%	0.81%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 10 - Apr 11 vs Nov 11 - Apr 12 - Commercial Rate G-52

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Commercial Rate (G-52)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,796	2,080	2,634	2,735	2,484	2,091	13,821	1,852	1,503	1,213	1,206	1,238	1,416	8,428	22,249
Winter:	07/01/2011	04/01/2011															
Cust. Chg	$122.32	$121.11	$122.32	$122.32	$122.32	$122.32	$122.32	$122.32	$733.92								
Headblock	$0.1684	$0.1667	$168.40	$168.40	$168.40	$168.40	$168.40	$168.40	$1,010.40								
Tailblock	$0.1143	$0.1131	$90.99	$123.45	$186.82	$198.34	$169.66	$124.65	$893.92								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.32	$121.11								$121.11	$121.11	$122.32	$122.32	$122.32	$122.32	$731.50	$1,465.42
Headblock	$0.1237	$0.1225								$122.50	$122.50	$123.70	$123.70	$123.70	$123.70	$739.80	$1,750.20
Tailblock	$0.0713	$0.0705								$60.04	$35.47	$15.22	$14.66	$16.98	$29.66	$172.03	$1,065.95
HB Threshold	1,000	1,000															
Total Base Rate Amount			$381.71	$414.17	$477.54	$489.06	$460.38	$415.37	$2,638.24	$303.65	$279.08	$261.24	$260.68	$263.00	$275.68	$1,643.33	$4,281.57
CGA Rate - (Seasonal)			$0.7911	$0.7911	$0.7911	$0.7911	$0.7911	$0.7911	$0.7911	$0.7256	$0.7359	$0.7542	$0.7814	$0.7511	$0.7511	$0.7476	$0.7746
CGA amount			$1,420.85	$1,645.53	$2,084.15	$2,163.89	$1,965.35	$1,653.86	$10,933.63	$1,343.50	$1,106.14	$915.18	$942.12	$930.02	$1,063.57	$6,300.52	$17,234.16
LDAC			$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	$0.0497	0.0497	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0488
LDAC amount			$89.27	$103.38	$130.94	$135.95	$123.48	$103.91	$686.93	$87.76	$71.25	$57.52	$57.15	$58.69	$67.12	$399.49	$1,086.42
Total Bill			**$1,891.83**	**$2,163.08**	**$2,692.64**	**$2,788.90**	**$2,549.21**	**$2,173.14**	**$14,258.80**	**$1,734.91**	**$1,456.47**	**$1,233.94**	**$1,259.95**	**$1,251.71**	**$1,406.37**	**$8,343.35**	**$22,602.14**

November 1, 2011 - April 30, 2012
Commercial Rate (G-52)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,796	2,080	2,634	2,735	2,484	2,091	13,821	1,852	1,503	1,213	1,206	1,238	1,416	8,428	22,249
Winter:	07/01/2010	06/01/2010															
Cust. Chg	$112.73		$112.73	$112.73	$112.73	$112.73	$112.73	$121.11	$684.76								
Headblock	$0.1692		169.20	169.20	169.20	169.20	169.20	166.70	$1,012.70								
Tailblock	$0.1148		$91.39	$123.99	$187.64	$199.21	$170.40	$123.35	$895.97								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$112.73	$111.63								$100.24	$111.63	$112.73	$112.73	$112.73	$112.73	$662.79	$1,347.55
Headblock	$0.1244	$0.1232								$110.60	$123.20	$124.40	$124.40	$124.40	$124.40	$731.40	$1,744.10
Tailblock	$0.0716	$0.0709								$54.25	$35.67	$15.28	$14.73	$17.06	$29.79	$166.77	$1,062.74
HB Threshold	1,000	1,000															
Total Base Rate Amount			$373.32	$405.92	$469.57	$481.14	$452.33	$411.16	$2,593.43	$265.09	$270.50	$252.41	$251.86	$254.19	$266.92	$1,560.96	$4,154.39
		08/01/2009															
CGA Rate - (Seasonal)		$100.24	$0.8186	$0.7625	$0.7856	$0.8064	$0.8314	$0.7956	$0.8003	$0.7202	$0.7118	$0.7930	$0.7295	$0.7538	$0.7077	$0.7334	$0.7749
CGA amount		$0.1106	$1,470.24	$1,586.00	$2,069.60	$2,205.67	$2,065.36	$1,663.27	$11,060.15	$1,333.50	$1,069.92	$962.26	$879.54	$933.36	$1,002.11	$6,180.69	$17,240.84
		$0.0637															
LDAC		1,000	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0336
LDAC amount			$75.79	$87.78	$111.18	$115.43	$104.84	$88.22	$583.24	$35.92	$29.16	$23.54	$23.39	$24.02	$27.47	$163.50	$746.74
Total Bill			**$1,919.35**	**$2,079.70**	**$2,650.35**	**$2,802.24**	**$2,622.53**	**$2,162.65**	**$14,236.82**	**$1,634.51**	**$1,369.58**	**$1,238.22**	**$1,154.79**	**$1,211.57**	**$1,296.50**	**$7,905.16**	**$22,141.97**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($27.52)**	**$83.38**	**$42.29**	**($13.34)**	**($73.33)**	**$10.50**	**$21.98**	**$100.40**	**$86.89**	**($4.28)**	**$105.16**	**$40.15**	**$109.87**	**$438.19**	**$460.17**
% Change	**-1.43%**	**4.01%**	**1.60%**	**-0.48%**	**-2.80%**	**0.49%**	**0.15%**	**6.14%**	**6.34%**	**-0.35%**	**9.11%**	**3.31%**	**8.47%**	**5.54%**	**2.08%**
Base Rate	$8.39	$8.25	$7.97	$7.92	$8.05	$4.22	$44.80	$38.56	$8.58	$8.83	$8.83	$8.82	$8.77	$82.38	$127.18
% Change	2.25%	2.03%	1.70%	1.65%	1.78%	1.03%	1.73%	14.55%	3.17%	3.50%	3.51%	3.47%	3.28%	5.28%	3.06%
CGA & LDAC	($35.92)	$75.13	$34.31	($21.26)	($81.37)	$6.28	($22.82)	$61.84	$78.31	($13.11)	$96.33	$31.33	$101.10	$355.81	$332.99
% Change	-2.44%	4.74%	1.66%	-0.96%	-3.94%	0.38%	-0.21%	4.64%	7.32%	-1.36%	10.95%	3.36%	10.09%	5.76%	1.93%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Residential Heating

	Winter 2010-11	Winter 2011-12
Customer Charge	$15.78	$17.33
First 100 Therms	$0.2774	$0.2741
Excess 100 Therms	$0.2091	$0.2265
LDAC	$0.0641	$0.0697
CGA	$0.8033	$0.7926
Total Adjust	$0.8674	$0.8623

		Winter 2010-11 CGA @	Winter 2011-12 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.8674	$0.8623	($0.01)	-1%						
Cooking alone	5	$21.50	$23.01	$1.51	7%	$1.53	7%	-$0.05	0%	$0.03	0%
	10	$27.23	$28.69	$1.47	5%	$1.52	6%	-$0.11	0%	$0.06	0%
	20	$38.68	$40.06	$1.38	4%	$1.48	4%	-$0.21	-1%	$0.11	0%
Water Heating alone	30	$50.12	$51.42	$1.30	3%	$1.45	3%	-$0.32	-1%	$0.17	0%
	45	$67.30	$68.47	$1.17	2%	$1.40	2%	-$0.48	-1%	$0.25	0%
	50	$73.02	$74.15	$1.13	2%	$1.39	2%	-$0.53	-1%	$0.28	0%
Heating Alone	80	$101.64	$102.56	$0.92	1%	$1.30	1%	-$0.80	-1%	$0.42	0%
	125	$165.78	$166.90	$1.12	1%	$1.79	1%	-$1.42	-1%	$0.75	0%
	150	$184.08	$185.41	$1.33	1%	$2.09	1%	-$1.60	-1%	$0.84	0%
	200	$237.91	$239.85	$1.94	1%	$2.96	1%	-$2.14	-1%	$1.12	0%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Variance Analysis of the Components of the 2010-11 Actual Results vs Proposed Winter 2011-12 Cost of Gas Rate

	WINTER SALES ACTUAL RESULTS (6 months actual)			**WINTER 2011-12 (6 months Proposed)**		
Therm Sales	82,202,526			82,632,661		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 8,031,841	$ 0.0977		$ 12,917,335	$ 0.1563
Purchased Gas	70,244,869	40,048,361	0.4872	66,241,118	35,469,665	0.4292
Storage Gas	13,620,070	8,176,366	0.0995	18,181,326	8,822,497	0.1068
Produced Gas	960,271	631,508	0.0077	856,615	381,653	0.0046
Hedging (Gain)/Loss		8,380,371	0.1019		2,091,917	0.0253
Total Volumes and Cost	84,825,210	$ 65,268,447	$ 0.7940	85,279,059	$ 59,683,068	$ 0.7223
Prior Period Balance		$ 2,985,736	$ 0.0363		3,735,297	$ 0.0452
Interest		138,289	0.0017		123,025	0.0015
Prior Period Adjustment		2,685	0.0000		-	-
Broker Revenues		(1,208,233)	(0.0147)		(1,417,572)	(0.0172)
Refunds from Suppliers		-	-		-	-
Fuel Financing		189,970	0.0023		182,975	0.0022
Transportation CGA Revenues		(32,528)	(0.0004)		-	-
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(459,206)	(0.0056)		(471,144)	(0.0057)
Hedging Costs		-	-		-	-
Misc Overhead		10,441	0.0001		2,833	0.0000
Occupant Disallowance/Credits		-				
Production & Storage		1,980,428	0.0241			
FPO Admin Costs		-	-		40,691	0.0005
Indirect Gas Costs		1,189,589	0.0145		3,613,742	0.0437
Total Adjusted Cost		$ 70,065,618	**$ 0.8524**		$ 65,492,914	**$ 0.7925**

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

Peak 2011 - 2012 Winter Cost of Gas Filing

Capacity Assignment Calculations 2011-2012

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

		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	643	672	0.5%		141	531
2	RATE R-3-Resi Htg	61,867	65,228	47.5%		3,851	61,377
3	RATE G-41 (T)	22,830	24,103	17.6%		844	23,259
4	RATE G-51 (S)	2,454	2,561	1.9%		618	1,943
5	RATE G-42 (V)	32,269	34,035	24.8%		1,773	32,262
6	RATE G-52	4,020	4,181	3.0%		1,252	2,929
7	RATE G-43	4,264	4,488	3.3%		388	4,100
8	RATE G-53	1,643	1,722	1.3%		288	1,434
9	RATE G-54	210	210	0.2%		210	-
10							
11	Total	130,202	137,200	100.0%		9,365	127,835
12							-
13	Residential Total	62,510	65,900	**48.032%**		3,992	61,908
14	LLF Total	59,363	62,626	**45.646%**		3,005	59,621
15	HLF Total	8,328	8,674	**6.322%**		2,368	6,306
16	Total	130,202	137,200	100.0%		9,365	127,835
17							
18	C&I Breakdown						
19	LLF Total					3,005	59,621
20	HLF Total					2,368	6,306
21	Total					5,373	65,927
22							
23	C&I Breakdown Percentage						
24	LLF Total					55.923%	90.435%
25	HLF Total					44.077%	9.565%
26	Total					**100.0%**	**100.0%**
27							

		Capacity Cost	MDQ, Dt	$/Dt-Mo.
28		Capacity Cost	MDQ, Dt	$/Dt-Mo.
29	Pipeline	$9,055,524	53,718	$14.0479
30	Storage	$5,742,137	28,115	$17.0198
31				
32	Peaking	$7,026,264		
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)	$2,613,758		
34	Subtotal Peaking Costs	$9,640,022	55,367	$14.5093
35	Total	$24,437,683	137,200	$14.8431
36				
37		Capacity Cost	MDQ, Dt	$/Dt-Mo.
38	Pipeline - Baseload	1,578,736	9,365	$14.0479
39	Pipeline - Remaining	7,476,788	44,353	$14.0479
40	Storage	5,742,137	28,115	$17.0198
41	Peaking	9,640,022	55,367	$14.5093
42	Total	24,437,683	137,200	$14.8431
43				
44				

45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.
46	Pipeline - Base	Line 38 * Line 13 Col C	**48.032%**	758,298	4,498	$14.0479
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**48.032%**	3,591,240	21,304	$14.0479
48	Storage	Line 40 * Line 13 Col C	**48.032%**	2,758,065	13,504	$17.0198
49	Peaking	Line 41 * Line 13 Col C	**48.032%**	4,630,324	26,594	$14.5093
50	Total		**48.032%**	11,737,929	65,900	$14.8431

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

Peak 2011 - 2012 Winter Cost of Gas Filing

Capacity Assignment Calculations 2011-2012

Derivation of Class Assignments and Weightings

51							
52							**Ratios for COG**
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		820,438	4,867	$14.0479	
55	Pipeline - Remaining	Line 39 - Line 47		3,885,548	23,049	$14.0480	
56	Storage	Line 40 - Line 48		2,984,071	14,611	$17.0198	
57	Peaking	Line 41 - Line 49		5,009,698	28,773	$14.5093	
58	Total		**51.968%**	12,699,755	71,300	$14.8431	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		458,815	2,722	$14.0465	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		3,513,888	20,845	$14.0477	
64	Storage	Line 56 * Line 24 Col F		2,698,639	13,213	$17.0201	
65	Peaking	Line 57 * Line 24 Col F		4,530,512	26,021	$14.5092	
66	Total		**45.8384%**	11,201,854	62,801	$14.8642	**1.0014**
67			55.923%	88%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		361,623	2,145	$14.0491	
71	Pipeline - Remaining	Line 55 - Line 63		371,660	2,204	$14.0525	
72	Storage	Line 56 - Line 64		285,432	1,398	$17.0143	
73	Peaking	Line 57 - Line 65		479,186	2,752	$14.5102	
74	Total		**6.1295%**	1,497,901	8,499	$14.6870	**0.9895**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 14.0479	$ 14.0479	$ 14.0479	
80	Storage			$ 17.0198	$ 17.0198	$ 17.0198	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 14.8431	$ 14.8642	$ 14.6870	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			39.15%	**37.53%**	**51.17%**	
88	Storage			20.49%	**21.04%**	**16.45%**	
89	Peaking			40.36%	**41.43%**	**32.38%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			48.03%	43.87%	8.10%	100.00%
96	Storage			48.03%	47.00%	4.97%	100.00%
97	Peaking			48.03%	47.00%	4.97%	100.00%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Correction Factor Calculation

Data Source: Schedule 10B

	Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
G-41	890,939	1,817,209	3,034,014	3,232,191	2,935,584	2,075,984	13,985,922
G-42	1,090,552	1,941,391	2,895,559	3,136,251	2,796,444	2,178,858	14,039,056
G-43	98,915	154,042	199,662	224,513	205,988	175,997	1,059,116
High Winter Use	2,080,407	3,912,642	6,129,235	6,592,955	5,938,016	4,430,839	29,084,094
G-51	200,133	291,857	373,783	384,479	367,453	318,243	1,935,948
G-52	298,144	372,633	440,349	453,312	456,023	394,511	2,414,972
G-53	36,561	42,286	50,448	58,085	51,759	49,699	288,839
G-54	1,818	1,827	1,504	1,385	1,504	1,837	9,875
Low Winter Use	536,656	708,603	866,083	897,261	876,740	764,290	4,649,633
Gross Total	2,617,062	4,621,246	6,995,318	7,490,216	6,814,756	5,195,129	33,733,727

Total Sales	33,733,727	
Low Winter Use	4,649,633	
Winter Ratio for Low Winter Use =	**0.98950**	Schedule 10A p 2, ln 74
High Winter Use	29,084,094	
Winter Ratio for High Winter Use =	**1.00140**	Schedule 10A p 2, ln 66

Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))

Correction Factor = **100.0240%**

Allocation Calculation for Miscellaneous Overhead

Projected Winter Sales Volume	(11/1/11 - 4/30/12)	82,647,332	Sch.10B
Projected Annual Sales Volume	(11/1/11 - 10/31/12)	105,300,939	Sch.10B
Percentage of Winter to Annual Sales		78.49%	

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **2011 - 2012 Winter Cost of Gas Filing**
5
6 **Dry Therms**

								Subtotal							**Subtotal**	
7	**Firm Sales**															
8		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**PK 11-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**OP 12**	**Total**
9	R-1	69,419	101,827	123,067	124,964	111,130	98,735	629,142	88,117	75,874	55,750	45,592	49,959	56,370	371,662	1,000,804
10	R-3	3,720,368	6,586,638	9,182,806	9,830,655	8,540,232	6,469,744	44,330,443	3,702,918	2,138,577	1,371,198	1,115,411	1,202,400	1,701,875	11,232,379	55,562,822
11	R-4	58,432	369,976	602,632	940,750	1,064,924	917,306	3,954,020	680,559	267,946	138,587	109,109	115,680	146,531	1,458,412	5,412,432
12	Total Residential.	3,848,220	7,058,441	9,908,505	10,896,369	9,716,286	7,485,784	48,913,605	4,471,593	2,482,396	1,565,536	1,270,112	1,368,039	1,904,776	13,062,453	61,976,058
13																
14	G-41	890,939	1,817,209	3,034,014	3,232,191	2,935,584	2,075,984	13,985,922	925,191	448,851	247,074	197,122	219,043	329,951	2,367,232	16,353,154
15	G-42	1,090,552	1,941,391	2,895,559	3,136,251	2,796,444	2,178,858	14,039,056	1,268,232	687,885	349,456	365,371	351,482	543,790	3,566,217	17,605,273
16	G-43	98,915	154,042	199,662	224,513	205,988	175,997	1,059,116	144,810	92,440	60,443	44,345	58,833	74,905	475,776	1,534,892
17	G-51	200,133	291,857	373,783	384,479	367,453	318,243	1,935,948	253,270	208,547	185,532	162,987	172,197	198,880	1,181,412	3,117,360
18	G-52	298,144	372,633	440,349	453,312	456,023	394,511	2,414,972	383,206	323,819	278,571	254,803	271,534	290,178	1,802,110	4,217,082
19	G-53	36,561	42,286	50,448	58,085	51,759	49,699	288,839	36,162	33,921	30,492	27,314	31,523	31,871	191,283	480,122
20	G-54	1,818	1,827	1,504	1,385	1,504	1,837	9,875	1,187	1,223	1,189	1,173	1,230	1,122	7,124	16,999
21	Total C/I	2,617,062	4,621,246	6,995,318	7,490,216	6,814,756	5,195,129	33,733,727	3,012,057	1,796,686	1,152,757	1,053,116	1,105,842	1,470,695	9,591,154	43,324,881
22																
23	**Sales Volume**	**6,465,283**	**11,679,687**	**16,903,823**	**18,386,585**	**16,531,042**	**12,680,913**	**82,647,332**	**7,483,651**	**4,279,083**	**2,718,293**	**2,323,228**	**2,473,881**	**3,375,472**	**22,653,607**	**105,300,939**
24																
25	Transportation Sales															
26																
27	G-41	229,155	401,008	585,576	637,155	587,215	460,796	2,900,904	242,635	153,355	94,507	73,030	80,955	114,092	758,575	3,659,479
28	G-42	915,775	1,675,589	2,416,319	2,615,279	2,352,859	1,846,515	11,822,336	1,077,156	585,562	317,771	249,183	285,853	460,167	2,975,692	14,798,028
29	G-43	512,603	798,830	1,038,161	1,155,239	1,045,715	929,746	5,480,293	532,426	334,188	205,956	185,400	221,369	276,019	1,755,360	7,235,653
30	G-51	47,502	72,700	95,971	96,646	100,744	105,763	519,326	57,842	42,968	50,221	43,831	44,342	67,914	307,119	826,446
31	G-52	242,423	312,036	387,785	413,128	414,386	362,830	2,132,587	276,364	221,233	175,465	170,166	184,683	206,153	1,234,065	3,366,652
32	G-53	706,611	830,475	979,482	1,139,496	1,009,267	974,833	5,640,164	822,958	779,833	703,048	629,680	728,786	732,960	4,397,264	10,037,428
33	G-54	1,553,302	1,560,981	1,284,421	1,182,026	1,284,266	1,569,494	8,434,490	1,653,709	1,704,656	1,657,757	1,635,381	1,714,428	1,563,546	9,929,478	18,363,969
34																
35	Total Trans. Sales	**4,207,370**	**5,651,619**	**6,787,715**	**7,238,969**	**6,794,452**	**6,249,976**	**36,930,101**	**4,663,092**	**3,821,795**	**3,204,726**	**2,986,671**	**3,260,417**	**3,420,852**	**21,357,553**	**58,287,654**
36																
37	Total All Sales	**10,672,653**	**17,331,306**	**23,691,538**	**25,625,554**	**23,325,494**	**18,930,889**	**119,577,433**	**12,146,742**	**8,100,878**	**5,923,019**	**5,309,899**	**5,734,298**	**6,796,324**	**44,011,159**	**163,588,592**

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11A**

Volumes (Therms) **Normal Year**

For the Months of November 11 - April 12

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	907,335	998,310	998,310	933,903	998,310	-	4,836,170
Niagara Supply	754,368	779,326	779,326	728,606	779,326	594,961	4,415,913
TGP Supply (Direct)	5,929,481	5,390,071	5,390,071	5,042,273	5,390,071	6,976,097	34,118,064
Dracut Supply 1 - Baseload	-	2,495,776	2,495,776	2,334,758	-	-	7,326,310
Dracut Supply 2 - Swing	4,247,650	754,368	1,524,034	2,135,096	6,431,051	2,569,844	17,662,044
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	22,542	23,348	689,961	22,542	46,695	-	805,089
Propane Truck	-	-	-	-	-	-	0
PNGTS	64,407	82,119	89,365	80,509	73,263	53,136	442,799
Granite Ridge	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	11,925,784	10,523,319	11,966,844	11,277,688	13,718,718	10,194,038	69,606,390
Storage Gas:							
TGP Storage	83,729	6,009,185	6,456,009	5,390,071	242,332	-	18,181,326
Produced Gas:							
LNG Vapor	22,542	23,348	742,292	22,542	23,348	22,542	856,615
Propane	-	-	-	-	-	-	0
Subtotal Produced Gas	22,542	23,348	742,292	22,542	23,348	22,542	856,615
Less - Gas Refills:							
LNG Truck	(22,542)	(23,348)	(689,961)	(22,542)	(46,695)	-	(805,089)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(713,309)	-	-	-	-	(1,846,874)	(2,560,183)
Subtotal Refills	(735,851)	(23,348)	(689,961)	(22,542)	(46,695)	(1,846,874)	(3,365,272)
Total Sendout Volumes	11,296,205	16,532,504	18,475,184	16,667,759	13,937,702	8,369,706	85,279,059

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11B**

Volumes (Therms) **Design Year**

For the Months of November 11 - April 12

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	966,107	998,310	998,310	933,903	998,310	-	4,894,941
Niagara Supply	754,368	779,326	779,326	728,606	779,326	613,478	4,434,431
TGP Supply (Direct)	6,988,173	5,390,071	5,390,071	5,042,273	5,390,071	6,980,122	35,180,782
Dracut Supply 1 - Baseload	-	2,495,776	2,495,776	2,334,758	-	-	7,326,310
Dracut Supply 2 - Swing	4,133,327	2,402,386	2,869,337	3,367,688	5,956,854	3,166,415	21,896,007
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	22,542	23,348	574,028	137,670	46,695	-	804,284
Propane Truck	-	-	-	-	-	-	0
PNGTS	64,407	82,119	89,365	80,509	73,263	53,136	442,799
Granite Ridge	-	-	128,814	805	-	-	129,619
Other Purchased Resources	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	12,928,925	12,171,336	13,325,029	12,626,212	13,244,520	10,813,151	75,109,174
Storage Gas:							
TGP Storage	1,189,922	5,868,294	6,724,104	5,547,869	1,994,206	53,136	21,377,530
Produced Gas:							
LNG Vapor	22,542	23,348	627,164	137,670	23,348	22,542	856,615
Propane	-	-	154,577	-	-	-	154,577
Subtotal Produced Gas	22,542	23,348	781,741	137,670	23,348	22,542	1,011,192
Less - Gas Refills:							
LNG Truck	(22,542)	(23,348)	(574,028)	(137,670)	(46,695)	-	(804,284)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(1,780,857)	-	-	-	-	(1,807,425)	(3,588,282)
Subtotal Refills	(1,803,399)	(23,348)	(574,028)	(137,670)	(46,695)	(1,807,425)	(4,392,566)
Total Sendout Volumes	12,337,990	18,039,631	20,256,846	18,174,080	15,215,378	9,081,405	93,105,329

ENERGY NORTH NATURAL GAS, INC. — **Schedule 11C**
d/b/a National Grid NH — **Page 1 0f 1**
Peak 2011 - 2012 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	4,836,170	4,000	7,240,000	67%	4,894,941	4,000	7,240,000	68%
Niagara Supply	4,415,913	3,122	5,650,820	78%	4,434,431	3,122	5,650,820	78%
TGP Supply (Direct)	34,118,064	21,596	39,088,760	87%	35,180,782	21,596	39,088,760	90%
Dracut Supply 1 & 2	24,988,354	50,000	90,500,000	28%	29,222,318	50,000	90,500,000	32%
LNG Truck	805,089	-	-	-	804,284	-	-	-
Propane Truck	-	-	-	-	-	-	-	-
PNGTS	442,799	1,000	1,810,000	24%	442,799	1,000	1,810,000	24%
Granite Ridge	-	-	-	-	129,619	-	-	-
Other Purchased Resources	-	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	69,606,390				75,109,174			
Storage Gas:								
TGP Storage	18,181,326		25,801,310	70%	21,377,530		25,801,310	83%
Produced Gas:								
LNG Vapor	856,615				856,615			
Propane	-				154,577			
Subtotal Produced Gas	856,615				1,011,192			
Less - Gas Refills:								
LNG Truck	(805,089)				(804,284)			
Propane	-				-			
TGP Storage Refill	(2,560,183)				(3,588,282)			
Subtotal Refills	(3,365,272)				(4,392,566)			
Total Sendout Volumes	85,279,059				93,105,329			

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

d/b/a National Grid NH

Peak 2011 - 2012 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2011 / 12 Heating Season
(Therms)

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

72 HDD at Manchester, N.H.

Requirements		
	Firm Sales	1,116,671
	Interruptible Sales	0
	Firm Transportation	255,329
	Interruptible Transportation	0
	Total Requirements	1,372,000
Resources		
	Purchased Pipeline Gas	793,700
	Underground Storage Gas	281,100
	Propane Air Production	191,900
	LNG Produced Gas	105,300
	Third-Party Supply	0
	Total Resources	1,372,000

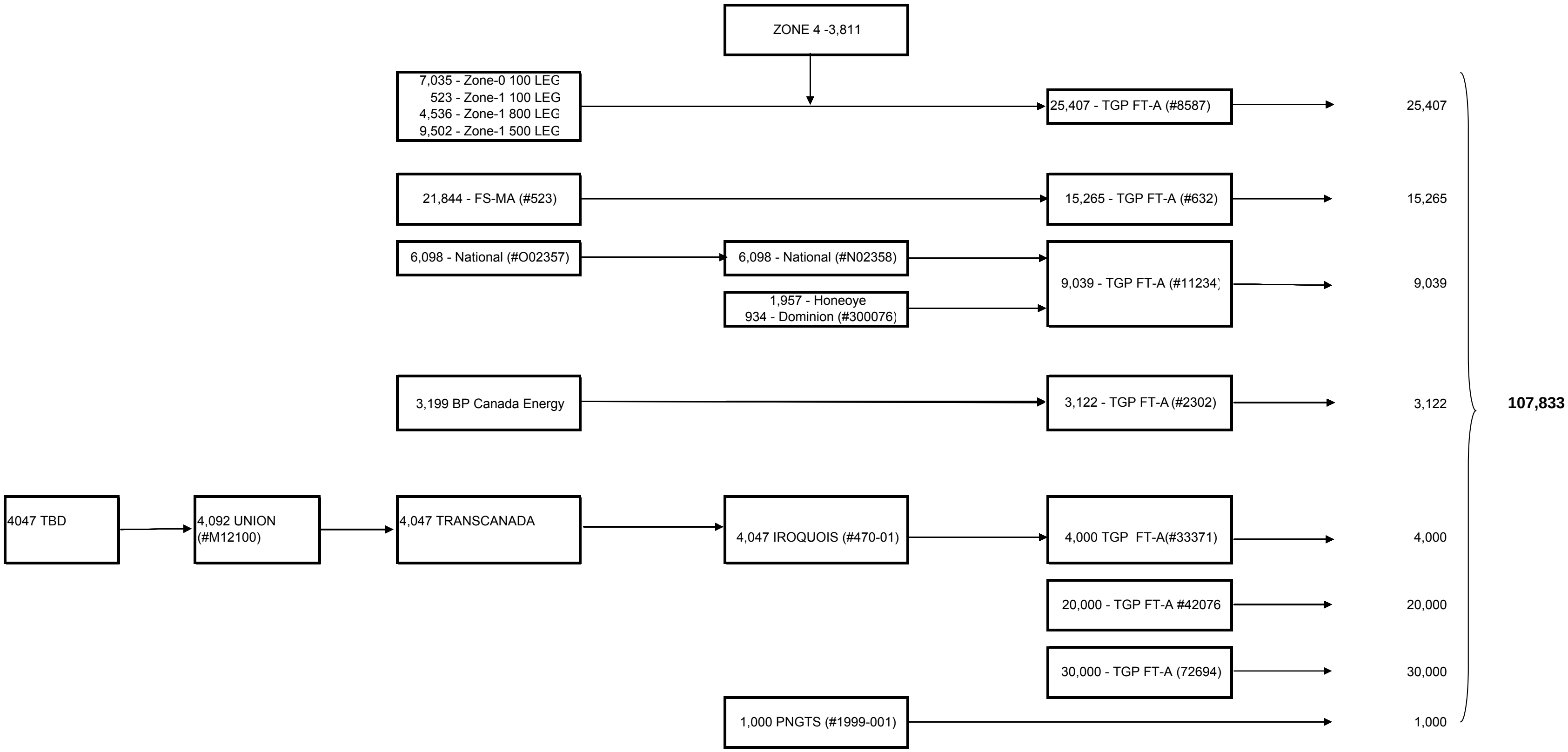
Please refer to the ENGI 2010 IRP filing (DG 10-041) for a complete description of the methodology and assumptions used in the derivation of this data.

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 2011 - 2012 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 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	09/30/2012	N/a	Mutually agreed upon.
BP Gas & Power Canada, Ltd	-	-	Supply	3,199	1,167,635	03/31/2012	N/a	Terminates
TBD (Currently No Supply for April through October 2011)	-	-	Supply	4,047	611,097	Peak Only	N/a	Terminates
Distrigas of Renew Massachusetts Corp.	FLS	FLS183	Liquid Refill	Up to 3 trucks	100,000 National Grid Total	03/31/2012 Peak Only	-	Terminates
Repsol Corporation	-	-	Supply	May 2011 = 26,624 Oct 2011 = 45,200	4,491,000	10/31/2012	-	Terminates
ConocoPhillips	-	-	Supply	21,596	3,908,876	04/30/2012	N/a	Terminates
Eastern Propane Gas (Trucking Only)			Trucking	28,500 Gallons	900,000 Gallons	03/31/2012	N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	03/31/2016	03/31/2009	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	04/01/2012	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	03/31/2012	03/31/2011	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	03/31/2012	03/31/2011	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/01/2017	10/31/2011	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	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	33371	Transportation	4,000	1,460,000	11/30/2011	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2015	10/31/2010	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2017	04/30/2016	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 2011 - 2012 Winter Cost of Gas Filing
Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2010 - Apr 2011 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	15,319,896	38.04%	81.81%
G-42	16,395,558	40.71%	54.33%
G-43	1,413,656	3.51%	17.40%
G-51	2,850,555	7.08%	79.03%
G-52	3,836,651	9.53%	55.45%
G-53	438,138	1.09%	4.58%
G-54	15,479	0.04%	0.09%
Total C/I	40,269,933	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	3,406,371	6.38%	18.19%
G-42	13,783,300	25.83%	45.67%
G-43	6,710,762	12.57%	82.60%
G-51	756,295	1.42%	20.97%
G-52	3,082,512	5.78%	44.55%
G-53	9,121,610	17.09%	95.42%
G-54	16,508,191	30.93%	99.91%
Total C/I	53,369,040	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	18,726,267	20.00%	100.00%
G-42	30,178,858	32.23%	100.00%
G-43	8,124,418	8.68%	100.00%
G-51	3,606,850	3.85%	100.00%
G-52	6,919,162	7.39%	100.00%
G-53	9,559,748	10.21%	100.00%
G-54	16,523,670	17.65%	100.00%
Total C/I	93,638,972	100.00%	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak May 10 - Oct 10 (Therms)	Peak Nov 10-Apr 11 (Therms)	Total May 10 - Apr 11 (Therms)	
Pipeline Deliveries	18,047,000	70,143,670	88,190,670	
All Others	446,870	14,681,540	15,128,410	
	18,493,870	84,825,210	103,319,080	
				Ratio
Total Winter Supplies				84,825,210
Total Pipeline Deliveries				88,190,670
Ratio Winter Supplies to Pipeline Supplies				0.962

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 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-10	Aug-10	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	198,142	222,551	420,693	16,055,309	2.62%
G-42	276,405	360,011	636,416	17,580,632	3.62%
G-43	66,254	19,285	85,539	2,656,032	3.22%
G-51	156,930	138,107	295,037	2,992,956	9.86%
G-52	251,262	221,554	472,816	4,363,627	10.84%
G-53	24,283	21,839	46,122	934,754	4.93%
G-54	992	907	1,899	(940,932)	-0.20%
Total C/I	974,268	984,254	1,958,521	43,642,378	4.49%

Ln	Description	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	**ENERGY NORTH NATURAL GAS, INC.**														
2	**d/b/a National Grid NH**														
3	**Peak 2011 - 2012 Winter Cost of Gas Filing**														
4	**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**														
5															
6	**Underground Storage Gas**														
7			May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		1,006,114	515,434	550,482	632,363	632,363	1,464,919	2,297,475	2,360,433	1,759,514	1,113,914	574,906	550,673	1,006,114
10															
11	Injections (MMBtu)	Sch 11A ln 37 /10	47,816	41,839	82,253	-	832,556	832,556	71,331	-	-	-	-	-	1,908,351
12															
13	Subtotal		1,053,930	557,273	632,735	632,363	1,464,919	2,297,475	2,368,806	2,360,433	1,759,514	1,113,914	574,906	550,673	
14															
15	Storage Sale		-					-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(538,496)	(6,791)	(372)	-	-	-	(8,373)	(600,918)	(645,601)	(539,007)	(24,233)	-	(2,363,792)
18															
19	Ending Balance (MMBTu)		515,434	550,482	632,363	632,363	1,464,919	2,297,475	2,360,433	1,759,514	1,113,914	574,906	550,673	550,673	550,673
20															
21															
22	Beginning Balance		$ 5,760,106	$ 2,926,031	$ 3,084,570	$ 3,457,257	$ 3,457,257	$ 7,308,032	$ 11,180,707	$ 11,454,012	$ 8,538,052	$ 5,405,271	$ 2,789,736	$ 2,672,145	5,760,106
23															
24	Injections	ln 11 * ln 36	222,876	196,278	374,721	-	3,850,774	3,872,676	313,935	-	-	-	-	-	8,831,259
25															
26	Subtotal		$ 5,982,982	$ 3,122,309	$ 3,459,291	$ 3,457,257	$ 7,308,032	$ 11,180,707	$ 11,494,642	$ 11,454,012	$ 8,538,052	$ 5,405,271	$ 2,789,736	$ 2,672,145	
27															
28	Storage Sale		$ -					$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (3,056,950)	$ (37,739)	$ (2,034)	$ -	$ -	$ -	$ (40,630)	$ (2,915,960)	$ (3,132,782)	$ (2,615,535)	$ (117,592)	$ -	(11,919,220)
31															
32	Ending Balance		$ 2,926,031	$ 3,084,570	$ 3,457,257	$ 3,457,257	$ 7,308,032	$ 11,180,707	$ 11,454,012	$ 8,538,052	$ 5,405,271	$ 2,789,736	$ 2,672,145	$ 2,672,145	$ 2,672,145
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$5.6768	$5.6028	$5.4672	$5.4672	$4.9887	$4.8665	$4.8525	$4.8525	$4.8525	$4.8525	$4.8525	$4.8525	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$4.6611	$4.6913	$4.5557	$0.0000	$4.6252	$4.6515	$4.4011	$4.6287	$4.7310	$4.7327	$4.7012	$4.7062	
37															
38	For Informational Purposes								Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
39	Summer Hedge Contracts - Vols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX								$4.3770	$4.2755	$4.3381	$4.3838	$4.4079	$4.4542	
42															
43	Hedged Volumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX								-	-	-	-	-	-	-
45	Hedge (Savings)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
46															
47	Month Dollar Average	ln (22 + ln 32) /2				$ 3,457,257	$ 5,382,645	$ 9,244,370	$ 11,317,360	$ 9,996,032	$ 6,971,662	$ 4,097,504	$ 2,730,940	$ 2,672,145	
48															
49	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					1.40%	1.33%	1.26%	1.25%	1.37%	1.40%	1.39%	1.38%	1.07%	
50															
51	Inventory Finance Charge	ln 47 * ln 49				$ 4,039	$ 5,979	$ 9,706	$ 11,830	$ 11,452	$ 8,114	$ 4,745	$ 3,138	$ 2,390	
52	Financial Expenses					500	500	500	500	500	500	500	500	500	
53	Total Inventory Finance Charges					$ 4,539	$ 6,479	$ 10,206	$ 12,330	$ 11,952	$ 8,614	$ 5,245	$ 3,638	$ 2,890	
54															
55															
38															

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
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39
40 **Liquid Propane Gas (LPG)**

Ln	Description	Reference	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
42			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
43	Beginning Balance		99,842	98,523	95,521	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	99,842
44															
45	Injections	Sch 11A ln 36 /10	3,862	-	-	-	-	-	-	-	-	-	-	-	3,862
46															
47	Subtotal		103,704	98,523	95,521	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	
48															
49	Withdrawals	Sch 11A ln 31 /10	(5,181)	(3,031)	-	-	-	-	-	-	-	-	-	-	(8,212)
50															
51	Adjustment for change in temperature		-	29	(6)	-	-	-	-	-	-	-	-	-	23
52															
53	Ending Balance		98,523	95,521	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515	95,515
54															
55															
56	Beginning Balance		$ 1,427,275	$ 1,411,950	$ 1,368,928	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,427,275
57															
58	Injections	ln 45 * ln 68	58,740	-	-	-	-	-	-	-	-	-	-	-	58,740
59															
60	Subtotal		$ 1,486,015	$ 1,411,950	$ 1,368,928	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	
61															
62	Withdrawals	ln 51 * ln 66	(74,064)	(43,022)	10,676	-	-	-	-	-	-	-	-	-	(106,410)
63															
64	Ending Balance		$ 1,411,950	$ 1,368,928	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604
65															
66	Average Rate For Withdrawals		$14.3294	$14.3312	$14.3312	$14.4439	$14.4439	$14.4439	$14.4439	$14.4439	$14.4439	$14.4439	$14.4439	$14.4439	
67															
68	Propane Rate for Injections	Actual or Sch. 6, ln 151 * 10	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
69															
70															
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	$ 1,379,604	
72															
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					1.40%	1.33%	1.26%	1.25%	1.37%	1.40%	1.39%	1.38%	1.07%	
74															
75	Inventory Finance Charge	ln 71 * ln 73				$ 1,612	$ 1,532	$ 1,449	$ 1,442	$ 1,581	$ 1,606	$ 1,598	$ 1,585	$ 1,234	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2011 - 2012 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
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71

Ln	Description	Reference	May-11 (Actual)	Jun-11 (Actual)	Jul-11 (Actual)	Aug-11 (Estimate)	Sep-11 (Estimate)	Oct-11 (Estimate)	Nov-11 (Estimate)	Dec-11 (Estimate)	Jan-12 (Estimate)	Feb-12 (Estimate)	Mar-12 (Estimate)	Apr-12 (Estimate)	Total
72	**Liquid Natural Gas (LNG)**														
73															
74	Beginning Balance		9,346	8,667	6,853	8,855	8,855	8,855	8,855	8,855	8,855	3,622	3,622	5,957	9,346
75															
76	Injections	Sch 11A ln 35 /10	1,877	106	3,602	-	-	-	2,254	2,335	68,996	2,254	4,670	-	86,094
77															
78	Subtotal		11,223	8,773	10,455	8,855	8,855	8,855	11,109	11,190	77,851	5,876	8,291	5,957	
79															
80	Withdrawals	Sch 11A ln 30 /10	(2,556)	(1,920)	(1,600)	-	-	-	(2,254)	(2,335)	(74,229)	(2,254)	(2,335)	(2,254)	(91,737)
81															
82	Ending Balance		8,667	6,853	8,855	8,855	8,855	8,855	8,855	8,855	3,622	3,622	5,957	3,702	3,702
83															
84															
85	Beginning Balance		$ 37,011	$ 35,651	$ 28,189	$ 38,517	$ 38,517	$ 38,517	$ 38,517	$ 38,180	$ 38,309	$ 16,165	$ 16,191	$ 26,566	$ 37,011
86															
87	Injections	ln 76 * ln 97	9,047	436	17,287	-	-	-	9,382	10,230	309,144	10,104	20,788	-	386,419
88															
89	Subtotal		$ 46,058	$ 36,087	$ 45,477	$ 38,517	$ 38,517	$ 38,517	$ 47,899	$ 48,410	$ 347,453	$ 26,269	$ 36,979	$ 26,566	
90															
91	Withdrawals	ln 80 * ln 95	(10,407)	(7,898)	(6,960)	-	-	-	(9,720)	(10,101)	(331,289)	(10,077)	(10,413)	(10,054)	(406,917)
92															
93	Ending Balance		$ 35,651	$ 28,189	$ 38,517	$ 38,517	$ 38,517	$ 38,517	$ 38,180	$ 38,309	$ 16,165	$ 16,191	$ 26,566	$ 16,513	$ 16,513
94															
95	Average Rate For Withdrawals		$4.1039	$4.1134	$4.3497	$4.3497	$4.3497	$4.3497	$4.3117	$4.3263	$4.4630	$4.4704	$4.4599	$4.4599	
96															
97	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$4.8198	$4.1134	$4.7994	$4.4822	$4.4518	$4.4079	$4.1621	$4.3818	$4.4806	$4.4822	$4.4518	$4.4079	
98															
99															
100	Month Dollar Average	ln (85 + ln 93) /2				$ 38,517	$ 38,517	$ 38,517	$ 38,348	$ 38,244	$ 27,237	$ 16,178	$ 21,379	$ 21,539	
101															
102	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					1.40%	1.33%	1.26%	1.25%	1.37%	1.40%	1.39%	1.38%	1.07%	
103															
104	Inventory Finance Charge	ln 100 * ln 102				$ 45	$ 43	$ 40	$ 40	$ 44	$ 32	$ 19	$ 25	$ 19	
105															
106															
107	Total Fuel Financing	lns 53 + 75 + 104				$ 6,196	$ 8,054	$ 11,695	$ 13,812	$ 13,576	$ 10,251	$ 6,861	$ 5,247	$ 4,143	
108															
100															

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas

REDACTED

Summer Hedge Program

Trade Dates	Contracts	May-11 (a)	Jun-11 (b)	Jul-11 (c)	Aug-11 (d)	Sep-11 (e)	Oct-11 (f)	Total (g)
		[redacted]						
		-	-	-	-	-	-	-
	Prices							
		[redacted]						
	Dollars							
		[redacted]						
00-Jan-00								
00-Jan-00								
00-Jan-00		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Hedge Contract Price		-	-	-	-	-	-	-
NYMEX		-	-	-	-	-	-	-
Hedged Volumes at Hedged Price		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less Hedged Volumes at NYMEX		-	-	-	-	-	-	-
Hedge (Savings)/Loss		$ -	$ -	$ -	$ -	$ -	$ -	-
Options Loss		$ -	$ -	$ -	-	-	-	$ -
Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 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-10	4,207,370	$0.0000	$ -
Dec-10	5,651,619	0.0000	-
Jan-11	6,787,715	0.0000	-
Feb-11	7,238,969	0.0000	-
Mar-11	6,794,452	0.0000	-
Apr-11	6,249,976	0.0000	-
Total	**36,930,101**		**$ -**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed Third Revised Page 89 for calculation of rate.

McLane

McLane, Graf, Raulerson & Middleton
Professional Association

Eleven South Main Street | Concord, NH 03301
Tel: 603.226.0400 | Fax: 603.230.4448 | www.mclane.com

MANCHESTER
CONCORD
PORTSMOUTH
WOBURN MA

STEVEN V. CAMERINO
Email: steven.camerino@mclane.com
Licensed in MA and NH

July 29, 2011

Via Hand Delivery

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

Re: DG 10-230
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
2010-11 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Enclosed are seven copies of the redacted version of the 2010-11 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 in both redacted and unredacted form in order to protect the confidentiality of information for which protective treatment was previously granted by the Commission in Order No. 25,161, dated October 28, 2010. This report is also being filed electronically with the Commission in accordance with Order Number 24,223 issued on October 24, 2003, in which the Commission ruled that the filing requirement would be satisfied by filing one electronic copy and one paper copy with the Commission. The Company is also filing separately a confidential version of the enclosed filing with the Commission today.

The enclosed reconciliation filing shows an under collection for the 2010-11 Winter Period of $3,735,297 summarized as follows:

Winter Period Beginning Balance	$2,985,736
Less: Cost of Gas Revenue Billed	($65,151,244)
Add: Cost of Gas Allowable (5/1/10 -10/31/10)	$2,825,095
Add: Cost of Gas Allowable (11/1/10 -4/30/11)	$63,075,709
Winter Period Ending Balance	$3,735,297

The reconciliation 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. This results in a net under collection of $3,735,297. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's original cost of gas filing, resulting in under collections of $36,020 and $8,916, respectively, for a net under collection for all the gas accounts of $3,780,233. Page 3 of the Summary compares actual demand charges of $8,031,841 to the $9,370,456 in demand charges estimated in the original cost of gas filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $56,585,957 compared to $53,693,195 in the original filing. The $2,892,762 increase in commodity costs was caused mainly by higher prices than originally forecasted. The results show that the actual demand and commodity costs were $1,554,146 higher than filed. Page 5 of the Summary provides a variance analysis that shows that weather resulted in a $1,824,369 increase in actual costs versus forecasted costs, changes in demand resulted in a $3,986,864 reduction in costs, and changes in gas prices resulted in a $3,716,641 increase in costs. 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. Schedule 1A 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.

Please do not hesitate to contact me with questions regarding this filing.

Sincerely,

Steven V. Camerino

Enclosures

cc: Meredith A. Hatfield, Esq.
Megan F. Tipper, Esq.
Ann E. Leary

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2010-2011 COST OF GAS RESULTS
DG 10-230
NOVEMBER 2010 THROUGH APRIL 2011

	Original Filing 1/	Actual		Difference
Peak Gas cost Account 175.20				
Balance 05/01/10 - (Over) / Under	$2,985,736	$2,985,736	2/	$0
Peak Gas Costs 5/1/10 - 10/31/10	$3,477,882	$3,717,238	3/	239,356
Fuel Financing 5/1/10 - 10/31/10	45,440	87,974	3/	42,534
Prior Period Adjustment 5/1/09-10/31/09	-	2,685	3/	2,685
Broker Revenue 5/1/10 - 10/31/10	(549,746)	(777,914)	3/	(228,168)
280 Day Margins 5/1/10 - 10/31/10	-	-	4/	-
IT Sales Margins 5/1/10 - 10/31/10	-	-	4/	-
Off System Sales Margin 5/1/10 - 10/31/10	(20,412)	(22,947)	4/	(2,535)
Capacity Release 5/1/10 - 10/31/10	(250,771)	(254,048)	4/	(3,277)
Interest 5/1/10 - 10/31/10	70,647	72,107	3/	1,460
Sum 5/1/10 - 10/31/10 costs	$2,773,040	$2,825,095		$52,055
Beginning Balance 10/31/10 (Over)/Under	$5,758,776	$5,810,831		$52,055
Interest 11/1/10 - 4/30/11	41,563	76,693		35,130
Prior Period Adjustments	-	-		0
Interruptible Sales Margin 11/1/10 - 4/30/11	-	-		-
280-Day Margin 11/1/10 - 4/30/11	-	-		-
Off System Sales Margin 11/1/09 -4/30/10	(1,912)	(162,931)		(161,019)
Capacity Release Credits 11/1/10 - 4/30/11	(457,619)	(19,280)		438,339
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	40,691	0		(40,691)
Broker Revenues 11/1/10 - 4/30/11	(205,033)	(430,318)		(225,285)
Production & Storage	1,749,387	1,980,428		231,041
Misc Overhead	20,100	10,441		(9,659)
Fuel Financing 11/1/10 - 4/30/11	85,395	101,996		16,601
Transportation Cost of Gas Revenue	(31,147)	(32,528)		(1,381)
Total Adjustment to Costs	$1,241,425	$1,524,500		$283,075
Gas Costs 11/1/10 - 4/30/11	$60,149,426	$61,551,210		$1,401,784
Total Gas Costs and Adjustments 11/10 - 04/11	$61,390,851	$63,075,709		$1,684,858
Gas Cost Billed	($67,149,627)	(65,151,244)		$1,998,383
Total (Over) / Under 04/30/10	$0	$3,735,297		$3,735,297

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2010-2011 COST OF GAS RESULTS
DG 10-230
NOVEMBER 2010 THROUGH APRIL 2011

	Original Filing 1/	Actual		Difference
Bad Debts Account 175.52				
Beginning Balance	($20,082)	($20,082)		$0
BD Costs 5/1/09-10/31/09	83,545	82,641	5/	(904)
Interest 5/1/09-10/31/09	357	341	5/	(16)
Beginning Balance 10/31/09 (Over)/Under	$63,820	$61,889		($920)
Bad Debt Costs 11/1/08 - 4/30/10	1,505,005	1,527,056		22,051
Bad Debt CGA Billed	(1,569,143)	(1,553,628)		15,515
Adjustment	-	-		0
Interest	318	703		385
Total (Over) / Under 04/30/10	$0	$36,020		$36,020
Working Capital Account 142.20				
Beginning Balance	($481,137)	($481,137)		$0
WC Costs 5/1/09-10/31/09	3,152	3,118	6/	(34)
Interest 5/1/09-10/31/09	(7,910)	(7,911)	6/	(1)
Beginning Balance 10/31/09 (Over)/Under	($485,895)	($484,666)		($35)
Working Capital Costs 11/1/08-4/30/10	54,522	77,993		23,471
Working Capital CGA Billed	435,190	419,233		(15,957)
Adjustment	-	-		0
Interest	(3,817)	(3,644)		173
Total (Over) / Under 04/30/10	$0	$8,916		$8,916
Total 175.20, 175.52, 142.20	$0	$3,780,233		$3,780,233

1/ As filed 09-01-10 in the Winter 2010-2011 Cost of Gas DG 10-230.
2/ The beginning balance is the sum of the actual April 30, 2010 balance $3,011,016 less the May 2010 Billings of $3,249,282, plus reverse of prior month unbilled $3,224,002.
3/ The 5/1/10 - 10/31/10 costs are per Schedule 1, page 1, of the Summer 2010 Reconciliation filed on January 31, 2011 in DG 10-051.
4/ The 5/1/10 - 10/31/10 costs are per Schedule 4, of the Summer 2010 Reconciliation filed on January 31, 2011 in DG 10-051.
5/ The 5/1/10 - 10/31/10 costs are per Schedule 1, page 3, of the Summer 2010 Reconciliation filed on January 31, 2011 in DG 10-051.
6/ The 5/1/10 - 10/31/10 costs are per Schedule 5, of the Summer 2010 Reconciliation filed on January 31, 2011 in DG 10-051.

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2010-2011 COST OF GAS RESULTS
DG 10-230
SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2010 THROUGH APRIL 2011

	Filing (a)	1/ Actual May 10 - Oct 10 (b)	Actual Nov 10 - Apr 11 (c)	Actual Total Peak Demand (d)=(b)+(c)	Difference (e)=(d)-(a)
Supplies:					
BP/Nexen	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ICE					
Subtotal Supply Demand Charges	$5,790	$0	$8,877	$8,877	$3,087
Pipelines:					
Iroquois Gas Trans	$160,191	$0	$139,297	$139,297	($20,894)
TGP NET 33371	254,640	-	217,526	217,526	($37,114)
TGP FTA Z5-Z6 2302	92,349	-	78,791	78,791	($13,558)
TGP FTA Z0 - Z6 8587	2,158,540	-	1,843,257	1,843,257	($315,283)
TGP Dracut FTA Z6 - Z6 42076	379,200	-	323,751	323,751	($55,449)
TGP (Concord Lateral) Z6-Z6	4,089,120	1,804,474	2,145,704	3,950,178	($138,942)
Portland Natual Gas Pipeline	164,410	-	177,078	177,078	$12,668
ANE (Uniongas and TransCanada)	288,495	-	350,049	350,049	$61,554
TGP FTA 632	1,078,930	456,848	462,371	919,218	($159,712)
TGP FTA 11234	616,332	267,723	272,381	540,104	($76,228)
National Fuel	245,959	105,175	105,384	210,559	($35,400)
Subtotal Pipeline Demand Charges	$9,528,166	$2,634,220	$6,115,589	$8,749,810	($778,356)
Peaking Supply					
Granite Ridge	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NJR					
DOMAC					
Repsol					
JP Morgan					
Subtotal Peaking Supply	$615,912	($76,869)	($108,125)	($184,994)	($800,906)
Propane					
Energy North Propane	$0	$0	$0	$0	$0
Storage:					
Demand & Capacity Charges	$1,297,178	$574,552	$563,255	$1,137,807	($159,371)
Other:					
Capacity Managed	($2,076,590)	(65,315)	($1,037,590)	($1,102,906)	$973,684
Pipeline Refunds	$0	$0	($576,753)	($576,753)	($576,753)
Total Demand Charges (Forward to Page 4)	$9,370,456	$3,066,588	$4,965,253	$8,031,841	($1,338,615)

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2010 Cost of Gas Reconciliation, DG 10-051 filed January 28, 2011.

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2010-2011 COST OF GAS RESULTS
DG 10-230
SUMMARY OF COMMODITY COSTS FOR PERIOD
NOVEMBER 2010 THROUGH APRIL 2011

	Filing	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 3):	$9,370,456		$8,031,841		($1,338,615)	
TGP Gulf Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
Dracut Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
PNGTS Comodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
TGP/Iroquois Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
TGP/Niagara Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
City Gate Delivered Supply						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
Storage Gas - Commodity Withdrawn						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
Propane P/S Plant Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
Propane Tank Farm Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
LNG P/S Plant Commodity						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
Hedging (Gains) Losses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Other- Cashout, Broker Penalty, Canadian Managed, Non-Firm costs						
Therms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Cost						
Prior period Adj	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Subtotal:						
Volumes (net of fuel retention)	85,919,142		84,825,210		(1,093,932)	
Cost	$ 53,693,195	0.6249	$ 56,585,957	0.6671	$ 2,892,762	0.0422
Total Demand and Commodity Costs	$ 63,063,651		$ 64,617,797		$ 1,554,146	
Demand (therms):	85,919,142		84,825,210		(1,093,932)	
Firm Gas Sales	83,071,582		82,202,526		(869,056)	
Lost Gas (Unaccounted For)	1,876,249		2,205,455		329,206	
Unbilled Therms	-		(556,655)		(556,655)	
Fuel Retention	-		-		-	
Company Use	971,312		973,884		2,572	
Total Demand	85,919,143		84,825,210		(1,093,933)	

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2010-2011 COST OF GAS RESULTS
DG 10-230

Weather Variance - Volume Impact	(A) Actual Volume	(B) Normal Volume	(C) Actual Rate	(A-B)*C Difference
TGP Gulf	[redacted]			
TGP/Iroquios				
TGP/Niagra				
PNGTS				
Dracut				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Volume Weather Varaince	84,825,210	81,516,441		$ 1,824,369

Demand Variance - Commodity Costs	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate	(B-A)*C Difference
TGP Gulf	[redacted]			
TGP/Iroquios				
TGP/Niagra				
PNGTS Comodity				
City Gate Delivered Supply				
Dracut				
Storage Gas - Commodity Withdrawn				
Propane P/S Plant Commodity				
LNG P/S Plant Commodity				
Total Demand Variance (Less: Fuel Retention)	85,919,142	84,825,210		$ (2,162,495)
Demand Variance Net of Weather Variance				(3,986,864)

Rate Variance - Commodity Costs	(A) Actual Volume	(B) Forecast Rate	(C) Actual Rate	(C-B)*A Difference
TGP Gulf	[redacted]			
TGP/Iroquios				
TGP/Niagra				
PNGTS Comodity				
Dracut				
DOMAC				
Storage Gas - Commodity Withdrawn				
Propane P/S Plant Commodity				
LNG P/S Plant Commodity				
Total Commodity Cost Rate Variance	84,825,210			$ 2,761,019
Demand Charge Variance (from page 3)				(1,338,615)
Other Rate Variance (from page 4)				
Hedging (Gains)/Losses				2,675,892
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments				(381,655)
Total Rate Variance				$ 3,716,641
Due to Weather Variance				1,824,369
Due to Demand Variance (from above)				(3,986,864)
Total Gas Cost Variance				$ 1,554,146

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2010-2011 COST OF GAS RESULTS
DG 10-230

	FILING	ACTUAL
Cost of Propane	$ 824,721	$ 504,364
Cost of LNG	431,227	429,244
Total Costs	1,255,948	933,609
Percentage of Supplies Used For Pressure Support Purposes	12.4%	12.4%
Cost of Supplies Used For Pressure Support Purposes	155,738	115,767
Firm Therms Sold	83,088,481	82,202,526
Firm Therms Transported	34,607,498	36,142,519
Total Therms	117,695,979	118,345,045
Actual Liquid Cost/Therm	0.0013	0.0010
Firm Therms Transported	34,607,498	36,142,519
Liquid Costs Allocated to Transported Therms	45,793	35,355
Prior (Over) or under Collection	(13,665)	(13,665)
Total	32,128	21,690
Costs Recovered:		
Therms Transported	34,607,498	36,142,519
Recovery Rate	0.0009	0.0009
Costs Recovered	32,128	32,528
(Over) / Under Collection For Period	-	(10,838)

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

	FOR THE MONTH OF: DAYS IN MONTH	Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	May-11	Total
1	BEGINNING BALANCE	$ 5,810,831	$ 4,301,445	$ 4,285,656	$ 4,731,205	$ 5,925,827	$ 4,389,320	$ 4,200,751	$ 5,810,831
2									
3	Add: Actual Costs	6,000,818	12,598,468	15,337,746	13,670,644	9,201,553	4,741,981		61,551,210
4									
5	Add. FPO Admin Costs	-	-	-	-	-	-		-
6	Add: MISC OH	1,740	1,740	1,740	1,740	1,740	1,740		10,441
7	Add: Production and Storage	330,071	330,071	330,071	330,071	330,071	330,071		1,980,428
8	Add: Fuel Financing	18,418	24,795	20,703	18,700	6,533	12,846		101,996
9	Reverse Fuel Finance Estimate		-			-			-
10	Add new Fuel Finance Estimate		-			-			-
11									-
12	Less CUSTOMER BILLINGS	(1,581,180)	(9,150,469)	(13,284,037)	(14,683,228)	(13,104,198)	(9,810,195)	(3,570,466)	(65,183,772)
13	Estimated Unbilled	(6,207,404)	(9,950,399)	(11,763,304)	(9,787,065)	(7,724,154)	(3,105,012)		(48,537,338)
14	Reverse Prior Month Unbilled		6,207,404	9,950,399	11,763,304	9,787,065	7,724,154	3,105,012	48,537,338
15	Sub-Total Accrued Customer Billings	(7,788,584)	(12,893,463)	(15,096,942)	(12,706,989)	(11,041,286)	(5,191,054)	(465,455)	(65,183,772)
16									
17	Less REFUND	-	-	-	-	-	-		-
18									
19	Less Broker Revenues	(69,450)	(87,252)	(69,039)	(130,537)	(47,165)	(26,875)	-	(430,318)
20									
21	NON FIRM MARGIN AND CREDITS	(15,888)	(1,984)	(91,158)	(2,275)	(2,170)	(68,737)	-	(182,212)
22									
23	ENDING BALANCE PRE INTEREST	$ 4,287,957	$ 4,273,821	$ 4,718,778	$ 5,912,559	$ 4,375,103	$ 4,189,293	$ 3,735,297	$ 3,658,604
24									
25	MONTH'S AVERAGE BALANCE	5,049,394	4,287,633	4,502,217	5,321,882	5,150,465	4,289,307		
26									
27	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
28									
29	INTEREST APPLIED	13,488	11,835	12,427	13,268	14,217	11,458		76,693
30									
31	ENDING BALANCE	$ 4,301,445	$ 4,285,655.61	$ 4,731,205	$ 5,925,827	$ 4,389,320	$ 4,200,751	$ 3,735,297	$ 3,735,297

REDACTED

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.40

	FOR THE MONTH OF: DAYS IN MONTH	Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	May-11	Total
1	BEGINNING BALANCE	$ (9,504)	$ (460,796)	$ (462,068)	$ (463,343)	$ (464,498)	$ (465,780)	$ (467,024)	(9,504)
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		$ -
4									
5	Add MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(3,043,580)	-	-	-	-	-	-	(3,043,580)
8	Estimated Unbilled		-	-	-	-	-		-
9	Reverse Prior Month Unbilled	2,592,915	-	-	-	-	-	-	2,592,915
10	Sub-Total Accrued Customer Billings	(450,664)	-	-	-	-	-	-	(450,664)
11									
12	Add ADJUSTMENTS	-	-	-	-	-	-	-	-
13									
14	ENDING BALANCE PRE INTEREST	$ (460,169)	$ (460,796)	$ (462,068)	$ (463,343)	$ (464,498)	$ (465,780)	$ (467,024)	$ (460,169)
15									
16	MONTH'S AVERAGE BALANCE	(234,837)	(460,796)	(462,068)	(463,343)	(464,498)	(465,780)		
17									
18	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
19									
20	INTEREST APPLIED	(627)	(1,272)	(1,275)	(1,155)	(1,282)	(1,244)		(6,855)
21									
22	ENDING BALANCE	$ (460,796)	$ (462,068)	$ (463,343)	$ (464,498)	$ (465,780)	$ (467,024)	$ (467,024)	$ (467,024)

REDACTED

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
MAY 2010 THROUGH OCTOBER 2010
PEAK BAD DEBT
SCHEDULE 1A
ACCOUNT 175.52

	FOR THE MONTH OF: DAYS IN MONTH	May-10 31	Jun-10 30	Jul-10 31	Aug-10 31	Sep-10 30	Oct-10 31	Nov-10 30	Total
1	BEGINNING BALANCE	$ (19,924)	$ (6,193)	$ 7,436	$ 20,585	$ 32,377	$ 46,789	$ 61,889	(19,924)
2									
3	Add: COST ALLOW	13,925	13,626	13,111	11,719	14,306	14,951	-	$ 81,637
4									
5	Adjustment	-	-	-	-	-	-	-	-
6									
7	Less: CUSTOMER BILLINGS	(75,037)	-	-	-	-	-	-	(75,037)
8	Estimated Unbilled	-	-	-	-	-	-		-
9	Reverse Prior Month Unbilled	74,879	-	-	-	-	-	-	74,879
10	Sub-Total Accrued Customer Billings	(158)	-	-	-	-	-	-	(158)
11									
12	ENDING BALANCE PRE INTEREST	$ (6,157)	$ 7,434	$ 20,546	$ 32,304	$ 46,683	$ 61,739	$ 61,889	$ 61,555
13									
14	MONTH'S AVERAGE BALANCE	(13,040)	620	13,991	26,445	39,530	54,264	61,889	
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17									
18	INTEREST APPLIED	(36)	2	39	73	106	150		$ 334
19									
20	ENDING BALANCE	$ (6,193)	$ 7,436	$ 20,585	$ 32,377	$ 46,789	$ 61,889	$ 61,889	$ 61,889

REDACTED

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
PEAK BAD DEBT
SCHEDULE 1A
ACCOUNT 175.52

	FOR THE MONTH OF: DAYS IN MONTH	Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	May-11	Total
1	BEGINNING BALANCE	$ 61,889	$ 34,544	$ 22,476	$ 32,707	$ 70,675	$ 48,187	$ 46,541	61,889
2									
3	Add: COST ALLOW	153,817	310,710	373,597	336,146	230,096	122,690		$ 1,527,056
4									
5	Adjustment	-	-	-	-	-	-	-	-
6									
7	Less: CUSTOMER BILLINGS	(36,129)	(217,968)	(326,693)	(352,725)	(307,313)	(227,539)	(85,259)	(1,553,628)
8	Estimated Unbilled	(145,162)	(250,050)	(286,799)	(232,381)	(177,815)	(74,739)		(1,166,946)
9	Reverse Prior Month Unbilled		145,162	250,050	286,799	232,381	177,815	74,739	1,166,946
10	Sub-Total Accrued Customer Billings	(181,291)	(322,856)	(363,442)	(298,307)	(252,748)	(124,463)	(10,521)	(1,553,628)
11									
12	ENDING BALANCE PRE INTEREST	$ 34,415	$ 22,397	$ 32,631	$ 70,546	$ 48,023	$ 46,415	$ 36,020	$ 35,317
13									
14	MONTH'S AVERAGE BALANCE	48,152	28,471	27,554	51,627	59,349	47,301		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17									
18	INTEREST APPLIED	129	79	76	129	164	126		$ 703
19									
20	ENDING BALANCE	$ 34,544	$ 22,476	$ 32,707	$ 70,675	$ 48,187	$ 46,541	$ 36,020	$ 36,020

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
MAY 2010 THROUGH OCTOBER 2010
OFF PEAK BAD DEBT
SCHEDULE 1A
ACCOUNT 175.54

	FOR THE MONTH OF: DAYS IN MONTH	May-10 31	Jun-10 30	Jul-10 31	Aug-10 31	Sep-10 30	Oct-10 31	Nov-10	Total
1	BEGINNING BALANCE	$ 63,205	$ 64,342	$ 58,259	$ 59,010	$ 61,285	$ 53,181	$ 25,923	63,205
2									
3	Add: COST ALLOW	66,503	39,391	37,351	40,536	36,797	78,828		$ 299,406
4									
5	Less: CUSTOMER BILLINGS	(30,453)	(58,629)	(44,406)	(37,423)	(40,443)	(54,414)	(84,423)	(350,192)
6	Estimated Unbilled	(35,088)	(22,098)	(14,454)	(15,457)	(20,068)	(71,849)	-	(179,014)
7	Reverse Prior Month Unbilled	-	35,088	22,098	14,454	15,457	20,068	71,849	179,014
8	Sub-Total Accrued Customer Billings	(65,542)	(45,639)	(36,762)	(38,427)	(45,054)	(106,194)	(12,574)	(350,192)
9									
10	ENDING BALANCE PRE INTEREST	$ 64,166	$ 58,095	$ 58,848	$ 61,119	$ 53,028	$ 25,814	$ 13,349	$ 12,419
11									
12	MONTH'S AVERAGE BALANCE	63,686	61,219	58,554	60,065	57,157	39,498		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15									
16	INTEREST APPLIED	176	164	162	166	153	109		$ 930
17									
18	ENDING BALANCE	$ 64,342	$ 58,259	$ 59,010	$ 61,285	$ 53,181	$ 25,923	$ 13,349	$ 13,349

REDACTED

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
OFF PEAK BAD DEBT
SCHEDULE 1A
ACCOUNT 175.54

	FOR THE MONTH OF: DAYS IN MONTH	Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	May-11	Total
1	BEGINNING BALANCE	$ 25,923	$ 13,401	$ 13,438	$ 13,475	$ 13,509	$ 13,546	$ 13,582	25,923
2									
3	Add: COST ALLOW	-	-	-	-	-	-		$ -
4									
5	Less: CUSTOMER BILLINGS	(84,423)	-	-	-	-	-	-	(84,423)
6	Estimated Unbilled		-	-	-	-	-		-
7	Reverse Prior Month Unbilled	71,849	-	-	-	-	-	-	71,849
8	Sub-Total Accrued Customer Billings	(12,574)	-	-	-	-	-	-	(12,574)
9									
10	ENDING BALANCE PRE INTEREST	$ 13,349	$ 13,401	$ 13,438	$ 13,475	$ 13,509	$ 13,546	$ 13,582	$ 13,349
11									
12	MONTH'S AVERAGE BALANCE	19,636	13,401	13,438	13,475	13,509	13,546		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15									
16	INTEREST APPLIED	52	37	37	34	37	36		233
17									
18	ENDING BALANCE	$ 13,401	$ 13,438	$ 13,475	$ 13,509	$ 13,546	$ 13,582	$ 13,582	$ 13,582

Schedule 2A
Page 1 of 1

REDACTED

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
GAS COSTS BY SOURCE
SCHEDULE 2A

FOR THE MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
DEMAND							
ALBERTA NORTHEAST	[redacted]						
BP/NORTHEAST GAS MARKETS							
CANADIAN CAPACITY MANAGED							
TOTAL CANADIAN DEMAND	$ (75,322.62)	$ (142,718.62)	$ (128,943.70)	$ (155,200.11)	$ (123,171.52)	$ (98,352.96)	$ (723,709.53)
PEAKING SUPPLY	(45,413.26)	(39,906.13)	(68,124.85)	(68,836.10)	(68,836.10)	(87,008.10)	(378,124.54)
TRANSPORT CAPACITY	958,456.05	947,158.96	971,896.69	956,758.22	960,353.37	993,681.94	5,788,305.23
CAPACITY RELEASE ADJUSTMENT	8,280.14	1,984.00	3,596.00	2,275.00	2,170.00	975.00	19,280.14
TOTAL TRANSPORT	$ 966,736.19	$ 949,142.96	$ 975,492.69	$ 959,033.22	$ 962,523.37	$ 994,656.94	$ 5,807,585.37
STORAGE FIXED COSTS	95,980.03	92,341.57	148,561.91	39,844.24	92,877.86	93,648.97	563,254.58
LNG	-	-	135,000.00	67,500.00	67,500.00	-	270,000.00
PROPANE	-	-	-	-	-	-	-
PIPELINE REFUNDS	-	-	(288,376.35)	-	-	(288,376.35)	(576,752.70)
OTHER	500.00	500.00	500.00	500.00	500.00	500.00	3,000.00
TOTAL DEMAND	$ 942,480.34	$ 859,359.78	$ 774,109.70	$ 842,841.25	$ 931,393.61	$ 615,068.50	$ 4,965,253.18
COMMODITY							
ALBERTA NORTHEAST / BP	[redacted]						
ALBERTA NORTHEAST / Emera							
SHELL CANADA							
TOTAL CANADIAN COMMODITY							
PIPELINE TRANSPORT							
DRACUT SUPPLY	[redacted]						
PNGTS							
GAS SUPPLY	[redacted]						
STORAGE	[redacted]						
LNG	[redacted]						
PROPANE	[redacted]						
OTHER COST ADJUSTMENTS							
CANDIAN CAPACITY MANAGED	[redacted]						
SUPPLIER CASHOUT							
NET OTHER COST ADJUSTMENTS							
SUBTOTAL COMMODITY COST	$ 5,076,630.46	$ 11,739,108.43	$ 14,612,075.19	$ 12,827,802.30	$ 8,270,158.95	$ 4,494,459.48	$ 57,020,234.81
OFF SYSTEM SALES COST	[redacted]						
OFF SYSTEM SALES COST (Propane)							
NON-FIRM COST							
TOTAL COMMODITY COST	$ 5,058,337.96	$ 11,739,108.43	$ 14,563,636.79	$ 12,827,802.30	$ 8,270,158.95	$ 4,126,912.12	$ 56,585,956.55

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
GAS COSTS SUMMARY
SCHEDULE 2A

FOR THE MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Total Peak Demand	$ 942,480.34	$ 859,359.78	$ 774,109.70	$ 842,841.25	$ 931,393.61	$ 615,068.50	$ 4,965,253.18
Off-Peak Demand	-	-	-	-	-	-	-
Total Demand	$ 942,480.34	$ 859,359.78	$ 774,109.70	$ 842,841.25	$ 931,393.61	$ 615,068.50	$ 4,965,253.18
Total Peak Commodity	$ 5,058,337.96	$ 11,739,108.43	$ 14,563,636.79	$ 12,827,802.30	$ 8,270,158.95	$ 4,126,912.12	$ 56,585,956.55
Off-Peak Commodity	-	-	-	-	-	-	-
Total Commodity	$ 5,058,337.96	$ 11,739,108.43	$ 14,563,636.79	$ 12,827,802.30	$ 8,270,158.95	$ 4,126,912.12	$ 56,585,956.55
Firm Sendout Costs	$ 6,000,818.30	$ 12,598,468.21	$ 15,337,746.49	$ 13,670,643.55	$ 9,201,552.56	$ 4,741,980.62	$ 61,551,209.73

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

	FOR THE MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	**DEMAND**							
2	**Supply**							
3	ALBERTA NORTHEAST	[redacted]						
4	Northeast Gas Markets/BP							
5	**Subtotal Canadian Supply**	$ 38,476.47	$ 57,341.61	$ 47,731.74	$ 47,300.55	$ 49,203.38	$ 73,826.93	$ 313,880.68
6	**Peaking Suppy**							
7	Repsol	[redacted]						
8	Granite Ridge							
9	NRJ							
10	JP Morgan							
11	**Subtotal Peaking Supply**	$ (45,413.26)	$ (39,906.13)	$ (68,124.85)	$ (68,836.10)	$ (68,836.10)	$ (87,008.10)	$ (378,124.54)
12								
13	**Transport Capacity**							
14	Iroquois 470-01-RTS	$ 22,962 80	$ 23,319 36	$ 23,276 58	$ 23,270 90	$ 23,223 95	$ 23,243.17	$ 139,296.76
15	National Fuel N02358	17,743 78	17,525.29	17,528 66	17,528.66	17,528 66	17,528 66	105,383.71
16	PNGTS FT-1999-001	23,251 07	14,457 02	42,471 60	26,325.48	30,026.48	28,166.48	164,698.13
17	Transcanada	-	-	-	-	-	35,144.83	35,144.83
18	TGP 632 FTA	77,706.77	77,035.31	76,911 62	76,905 73	76,905.73	76,905 73	462,370.89
19	TGP 2302 FTA Zone 5-6	13,261 70	13,133.52	13,103 94	13,099 01	13,099.01	13,094.08	78,791.26
20	TGP 8587 FTA	310,054.99	307,263 54	306,449.47	306,525 85	306,466.95	306,496.40	1,843,257.20
21	TGP 11234 FTA	45,695 23	45,383.06	45,330 05	45,324.16	45,324 16	45,324.16	272,380.82
22	TGP 33371 NET	36,593.89	36,222.54	36,222.54	36,211.93	36,137 66	36,137.66	217,526.22
23	TGP 72694 NET	356,704.26	357,895 36	357,748 07	357,735.90	357,810 17	357,810 17	2,145,703.93
24	TGP 42076 FTA	54,481.56	54,923 96	52,854 16	53,830.60	53,830.60	53,830 60	323,751.48
25	**Subtotal Transport Capacity**	$ 958,456.05	$ 947,158.96	$ 971,896.69	$ 956,758.22	$ 960,353.37	$ 993,681.94	$ 5,788,305.23
26								
27	**Storage Fixed**							
28	Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Dominion 300076-Storage	4,546.40	1,260.67	2,783.25	2,781.32	2,864.51	2,698 13	16,934.28
30	NFG Deliverability FSS 2357	36,401 03	36,085 66	36,028 88	36,965.77	35,090.79	36,028.28	216,600.41
31	Tenn Reservation FSMA 523	46,288.21	46,250 85	101,005.39	(8,647.24)	46,178 17	46,178.17	277,253.55
32	HONEOYE STORAGE SS-NY	8,744.39	8,744 39	8,744.39	8,744 39	8,744 39	8,744 39	52,466.34
33	Subtotal Storage	$ 95,980.03	$ 92,341.57	$ 148,561.91	$ 39,844.24	$ 92,877.86	$ 93,648.97	$ 563,254.58
34								
35	LNG / DISTRIGAS FLS 164	[redacted]						
36	LNG/ DISTRIGAS FLS160							
37	Transgas Trucking							
38	Subtotal Distrigas	$ -	$ -	$ 135,000.00	$ 67,500.00	$ 67,500.00	$ -	$ 270,000.00
39								
40	Propane							
41	En Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42								
43	Intercontinental Exchange	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	3,000.00
44								
45	Capacity Managed - Canadian	[redacted]						
46								
47	PNGTS Refund per RP02-13	[redacted]						
48	TGP Pipeline Refund	$ -	$ -	$ (288,376.35)	$ -	$ -	$ (288,376.35)	(576,752.70)
49								
50	Demand Subtotal	$ 934,200.20	$ 857,375.78	$ 770,513.70	$ 840,566.25	$ 929,223.61	$ 614,093.50	$ 4,945,973.04
51								
52	Capacity Release Adjustment							
53	ALBERTA NORTHEAST	[redacted]						
54	TGP - FT-A 632							
55	TGP - FT-A 11234							
56	TGP - FT-A 8587							
57	PNGTS - FT							
58								
59								
60	TOTAL DEMAND	$ 942,480.34	$ 859,359.78	$ 774,109.70	$ 842,841.25	$ 931,393.61	$ 615,068.50	$ 4,965,253.18

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

61	FOR THE MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
62								
63	**COMMODITY**							
64								
65	**Canadian Supply**							
66	BP	[redacted]						
67	ANE Union/Dawn/Iroquois (Emera)							
68	Shell Canada							
69	**Subtotal Canadian Commodity**							
70								
71	**Pipeline Transport**							
72	ANE Union/Dawn	[redacted]						
73								
74	Dominion							
75	El Paso							
76	Iroquois							
77	National Fuel							
78	PNGTS							
79	**Subtotal TGP Transportation**							
80	**Total Transportation**							
81								
82	**City Gate Delivery**							
83	VPEM	[redacted]						
84								
85	**Dracut Supply (Repsol)**							
86								
87	**PNGTS Supply**							
88	Emera							
89	Shell							
90								
91	**Subtotal PNGTS**							
92								
93	**Gas Supply**							
94	Andarko	[redacted]						
95	J Aron							
96	ANP							
97	Barclay							
98	BP Energy							
99	Chevron							
100	Conoco							
101	Emera							
102	EnCan							
103	Enjet							
104	JP Morgan							
105	Hess							
106	L. Dreyfus							
107	Macquarie							
108	Merrill							
109	NJR Energy							
110	Nextera							
111	Repsol							
112	Shell US							
113	Tenaska							
114	Total Gas & Power							
115	VPEM							
116	**Total Other TGP Supply**							
117								
118	**Peaking Supply**							
119	Granite Ridge (formerly AES)	[redacted]						
120								
121	NYMEX Hedging (Gains) Losses							
122								
123	**STORAGE WITHDRAWALS**							
124								
125	**STORAGE INJECTIONS**							
126								
127	DISTRIGAS (FCS 064)							
128	LNG VAPOR							
129	LNG BOIL OFF							
130	**Subtotal LNG**							
131	**PROPANE**							
132	Country Gas							
133	Propane Storage Withdrawal							
134	Energy North Propane							
135	**Subtotal Propane**							
136								
137	Broker Cashout							
138	Other Taxes W Virginia							
139	**Subtotal Cashouts**							
140								
141	Capacity Managed - Canadian							
142	Broker Inventory							
143	**Subtotal Capacity Managed**							
144								
145	**TOTAL COMMODITY**							
146								
147	Off System Gas Sales Cost							
148	Off System Sales Costs - Propane							
149	NON-FIRM COST							
150								
151	NET COMMODITY COST	$ 5,058,337.96	$ 11,739,108.43	$ 14,563,636.79	$ 12,827,802.30	$ 8,270,158.95	$ 4,126,912.12	$ 56,585,956.55

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
152	**FOR THE MONTH OF:**		**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**Total**
153									
154	Peak Demand 175.20		$ 942,480 34	$ 859,359 78	$ 774,109 70	$ 842,841.25	$ 931,393.61	$ 615,068 50	$ 4,965,253 18
155	Peak Commodity 175 20		5,058,337 96	11,739,108.43	14,563,636.79	12,827,802 30	8,270,158.95	4,126,912.12	56,585,956.55
156	Total Peak Gas Costs		$ 6,000,818.30	$ 12,598,468.21	$ 15,337,746.49	$ 13,670,643.55	$ 9,201,552.56	$ 4,741,980.62	$ 61,551,209.73
157									
158	Off-Peak Demand 175 40	OP	-	-	-	-	-		-
159	Off-Peak Comm 175.40	OP	-	-	-	-	-	-	-
160	Total Off-Peak Gas Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
161									
162	Firm Sendout Costs		$ 6,000,818.30	$ 12,598,468.21	$ 15,337,746.49	$ 13,670,643.55	$ 9,201,552.56	$ 4,741,980.62	$ 61,551,209.73

Schedule 3
Page 1 of 1

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	Nov-10 OffPeak	Nov-10 Peak	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11 Peak	Total Peak	Total OffPeak
1	VOLUMES										
2	RESIDENTIAL										
3	R-1	48,922	14,006	91,281	112,896	114,689	98,488	86,486	50,322	568,168	48,922
4	R-1 FPO	2,823	1,321	8,265	10,260	9,890	9,495	7,810	4,465	51,506	2,823
5	R-3	2,203,539	946,066	5,546,915	7,954,997	8,488,259	7,144,523	5,276,692	1,810,976	37,168,428	2,203,539
6	R-3 FPO	317,644	171,262	988,936	1,399,924	1,465,035	1,240,677	915,374	326,315	6,507,523	317,644
7	R-4	54,606	4,349	287,940	495,112	772,469	862,515	732,481	378,269	3,533,135	54,606
8	R-4 FPO	(2,042)	107	78,256	117,727	178,971	182,861	145,426	67,289	770,637	(2,042)
9	Total Residential	2,625,492	1,137,111	7,001,593	10,090,916	11,029,313	9,538,559	7,164,269	2,637,636		
10	COMMERCIAL/INDUSTRIAL										
11	G41 - G43	1,281,247	563,529	3,460,370	5,747,332	6,133,867	5,347,058	3,801,192	1,380,963	26,434,311	1,281,247
12	G41 - G43 (FPO)	93,959	58,291	365,039	578,735	623,313	536,188	382,327	136,389	2,680,282	93,959
13	Total G41- G43	1,375,206	621,820	3,825,409	6,326,067	6,757,180	5,883,246	4,183,519	1,517,352		
14	G51 - G63	375,489	136,520	646,287	796,234	804,968	772,695	633,794	328,182	4,118,680	375,489
15	G51 - G63 (FPO)	20,830	16,154	59,433	72,120	71,234	65,468	57,540	27,907	369,856	20,830
16	Total G51-G63	396,319	152,674	705,720	868,354	876,202	838,163	691,334	356,089		
17	Total Sales Volumes	4,397,017	1,911,605	11,532,722	17,285,337	18,662,695	16,259,968	12,039,122	4,511,077	82,202,526	4,397,017
18	TRANSPORTATION										
19	G41 - G43	1,303,180	318,443	2,852,099	4,112,703	4,459,391	3,913,666	3,097,663	1,408,731	20,162,696	1,303,180
20	G51 - G63	2,368,054	63,344	2,665,425	2,657,447	2,749,119	2,746,777	2,869,372	2,228,339	15,979,823	2,368,054
21	Total Transportation Volumes	3,671,234	381,787	5,517,524	6,770,150	7,208,510	6,660,443	5,967,035	3,637,070	36,142,519	3,671,234
22	Total Volumes	8,068,251	2,293,392	17,050,246	24,055,487	25,871,205	22,920,411	18,006,157	8,148,147	118,345,045	8,068,251
23											
24	RATES										
25	Residential	0.69290	0.80820	0.79070	0.75890	0.78050	0.80320	0.81120	0.78520		
26	Residential (FPO)	0.69290	0.8282	0.82820	0.82820	0.82820	0.82820	0.82820	0.82820		
27	C/I Sales G41 to G43	0.69320	0.80960	0.79190	0.75990	0.78170	0.80390	0.81370	0.78660		
28	C/I Sales G41 to G43 (FPO)	0.69320	0.8296	0.82960	0.82960	0.82960	0.82960	0.82960	0.82960		
29	C/I Transport G41 to G43	0.00000	0.0009	0.00090	0.00090	0.00090	0.00090	0.00090	0.00090		
30	C/I Sales G51 to G63	0.69220	0.80480	0.78830	0.75510	0.77680	0.79940	0.80830	0.78180		
31	C/I Sales G51 to G63 (FPO)	0.69220	0.8248	0.82480	0.82480	0.82480	0.82480	0.82480	0.82480		
32	C/I Transport G51 to G63	0.00000	0.0009	0.00090	0.00090	0.00090	0.00090	0.00090	0.00090		
33											
34	REVENUES										
35	Residential	$ 1,598,567	$ 779,445	$ 4,685,796	$ 6,498,464	$ 7,317,513	$ 6,510,358	$ 4,944,799	$ 1,758,508	$ 32,494,883	$ 1,598,567
36	Residential (FPO)	$ 220,637	$ 143,022	$ 890,693	$ 1,265,416	$ 1,369,757	$ 1,186,838	$ 885,023	$ 329,681	$ 6,070,429	$ 220,637
37	C/I Sales G41 to G43	$ 888,160	$ 456,233	$ 2,740,267	$ 4,367,398	$ 4,794,844	$ 4,298,500	$ 3,093,030	$ 1,086,265	$ 20,836,537	$ 888,160
38	C/I Sales G41 to G43 (FPO)	$ 65,132	$ 48,358	$ 302,836	$ 480,119	$ 517,100	$ 444,822	$ 317,178	$ 113,148	$ 2,223,562	$ 65,132
39	C/I Transport G41 to G43	$ -	$ 287	$ 2,567	$ 3,701	$ 4,013	$ 3,522	$ 2,788	$ 1,268	$ 18,146	$ -
40	C/I Sales G51 to G63	$ 259,913	$ 109,871	$ 509,468	$ 601,236	$ 625,299	$ 617,692	$ 512,296	$ 256,573	$ 3,232,436	$ 259,913
41	C/I Sales G51 to G63 (FPO)	$ 14,419	$ 13,324	$ 49,020	$ 59,485	$ 58,754	$ 53,998	$ 47,459	$ 23,018	$ 305,057	$ 14,419
42	C/I Transport G51 to G63	$ -	$ 57	$ 2,399	$ 2,392	$ 2,474	$ 2,472	$ 2,582	$ 2,006	$ 14,382	$ -
43	Winter Gas Cost Rev filed	$ 3,046,828	$ 1,550,597	$ 9,183,047	$ 13,278,211	$ 14,689,755	$ 13,118,203	$ 9,805,155	$ 3,570,466	$ 65,195,433	$ 3,046,828
44											
45	Winter Proration	$ -	$ 30,583	$ (32,367)	$ 7,172	$ (5,212)	$ (13,710)	$ 5,728	$ -	(7,806)	-
46											
47	Less Occupant Billing	$ 3,249	$ -	$ 211	$ 1,346	$ 1,315	$ 295	$ 687	$ -	3,854	3,249
48	Total	$ 3,043,580	$ 1,581,180	$ 9,150,469	$ 13,284,037	$ 14,683,228	$ 13,104,198	$ 9,810,195	$ 3,570,466	$ 65,183,772	$ 3,043,580
49											
50	Summer Gas Cost Billed (Acct 175.40)	$ 3,043,580									$ 3,046,828
51											
52	Winter Gas Costs Billed (Acct 175.20)		$ 1,580,837	$ 9,145,503	$ 13,277,944	$ 14,676,740	$ 13,098,203	$ 9,804,825	$ 3,567,193	$ 65,151,244	
53	Winter Transportation Gas Costs Billed (Acct 175.20)	-	344	4,966	6,093	6,488	5,994	5,370	3,273	$ 32,528	$ -
54	Total Winter Gas Cost Billed (Acct 175.20)	$ -	$ 1,581,180	$ 9,150,469	$ 13,284,037	$ 14,683,228	$ 13,104,198	$ 9,810,195	$ 3,570,466	$ 65,183,772	$ 3,046,828
55											
56											
57	Total Sales CGA Billed	$ 3,043,580	$ 1,581,180	$ 9,150,469	$ 13,284,037	$ 14,683,228	$ 13,104,198	$ 9,810,195	$ 3,570,466	$ 65,183,772	$ 3,043,580
58											
59	Plus Working Capital Gas Cost Billed	(16,269)	(9,749)	(58,817)	(88,155)	(95,180)	(82,926)	(61,400)	(23,006)	(419,233)	(16,269)
60	Plus Bad Debt Cost Billed	84,423	36,129	217,968	326,693	352,725	307,313	227,539	85,259	1,553,628	84,423
61	Plus Broker Revenues	-	69,450	87,252	69,039	130,537	47,165	26,875	-	430,318	-
62											
63	Total Winter Gas Costs Billed	$ 3,111,733	$ 1,677,011	$ 9,396,872	$ 13,591,614	$ 15,071,310	$ 13,375,751	$ 10,003,210	$ 3,632,719	$ 66,748,486	$ 3,111,733

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)

	FOR MONTH OF:	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	Firm Gas Purchases		9,943,330	17,724,900	19,961,380	16,413,040	13,905,580	6,876,980	84,825,210
2	Firm Sales		1,911,605	11,532,722	17,285,337	18,662,695	16,259,968	12,039,122	77,691,449
3	Company Use		92,669	181,706	212,660	202,839	171,149	112,861	973,884
4	Unaccounted For %		2 6%	2.6%	2.6%	2.6%	2 6%	2.6%	
5	Unaccounted For Gas		258,527	460,847	518,996	426,739	361,545	178,801	2,205,455
6	COG Factor- Gas Cost Only		$0.8082	$0.7521	$0.7752	$0.7960	$0 8210	$0.7852	
7	COG Factor- Bad Debt Factor		$0 0189	$0 0189	$0.0189	$0.0189	$0.0189	$0.0189	
8	COG Factor- Working Capital Factor		-$0 0051	-$0.0051	-$0 0051	-$0.0051	-$0.0051	-$0.0051	
9									
10	Unbilled Volume								
11	Beginning Bal		-	7,680,529	13,230,154	15,174,541	12,295,308	9,408,226	
12	Incremental Unbilled		7,680,529	5,549,625	1,944,387	(2,879,233)	(2,887,082)	(5,453,804)	
13	Ending Balance	-	7,680,529	13,230,154	15,174,541	12,295,308	9,408,226	3,954,422	
14									
15	COG Factor- Gas Cost Only		$0.8082	$0.7521	$0 7752	$0.7960	$0.8210	$0.7852	
16	Gross Unbilled Gas Cost	$2,592,915	$6,207,404	$9,950,399	$11,763,304	$9,787,065	$7,724,154	$3,105,012	
17									
18	Monthly Incremental Gas Cost		$3,614,488	$3,742,995	$1,812,905	($1,976,239)	($2,062,912)	($4,619,142)	
19									
20	COG Factor- Bad Debt Only		$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	
21	Gross Unbilled Bad Debt Cost	$19,318	$145,162	$250,050	$286,799	$232,381	$177,815	$74,739	
22									
23	Monthly Incremental Bad Debt Cost		$125,844	$104,888	$36,749	($54,418)	($54,566)	($103,077)	
24									
25	COG Factor- Working Capital Only		($0.0051)	($0.0051)	($0.0051)	($0 0051)	($0.0051)	($0 0051)	
26	Gross Unbilled Working Capital Cost	$5,795	($39,171)	($67,474)	($77,390)	($62,706)	($47,982)	($20,168)	
27									
28	Monthly Incremental Working Capital Cost		($44,966)	($28,303)	($9,916)	$14,684	$14,724	$27,814	

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	INTERRUPTIBLE	[redacted]						
2								
3	280 DAY	[redacted]						
4								
5	OFF SYSTEM GAS SALES MARGIN	[redacted]						
6	PROPANE OFF SYSTEM SALES MARGIN							
7								
8	CAPACITY RELEASE CREDIT	[redacted]						
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	$ (15,888)	$ (1,984)	$ (91,158)	$ (2,275)	$ (2,170)	$ (68,737)	$ (182,212)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2010 THROUGH APRIL 2011
PEAK PERIOD WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF DAYS IN MONTH	Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	May-11	Total
1	BEGINNING BALANCE	$ (484,666)	$ (429,359)	$ (327,273)	$ (210,566)	$ (113,102)	$ (33,411)	$ 6,077	$ (484,666)
2									
3	Add: COST ALLOW	7,606	16,009	19,377	17,371	11,691	5,939		77,993
4									
5	Less CUSTOMER BILLINGS	9,749	58,817	88,155	95,180	82,926	61,400	23,006	419,233
6	Estimated Unbilled	39,171	67,474	77,390	62,706	47,982	20,168		314,890
7	Reverse Prior Month Unbilled	-	(39,171)	(67,474)	(77,390)	(62,706)	(47,982)	(20,168)	(314,890)
8	Subtotal: Accrued Customer Billings	48,920	87,120	98,072	80,496	68,202	33,585	2,839	419,233
9									
10	Adjustment	-	-	-	-	-	-	-	-
11									
12	ENDING BALANCE PRE INTEREST	(428,140)	(326,230)	(209,825)	(112,699)	(33,209)	6,113	8,916	12,560
13									
14	MONTH'S AVERAGE BALANCE	(456,403)	(377,794)	(268,549)	(161,633)	(73,156)	(13,649)		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17	INTEREST APPLIED	(1,219)	(1,043)	(741)	(403)	(202)	(36)		(3,644)
18	ENDING BALANCE	$ (429,359)	$ (327,273)	$ (210,566)	$ (113,102)	$ (33,411)	$ 6,077	$ 8,916	$ 8,916

Schedule 5
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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2010 THROUGH APRIL 2011
OFF PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF DAYS IN MONTH	Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	May-11	Total
1	BEGINNING BALANCE	$ (14,515)	$ (12,128)	$ (12,161)	$ (12,195)	$ (12,225)	$ (12,259)	$ (12,292)	(14,515)
2									
3	Add ACTUAL COST	-	-	-	-	-	-		$ -
4									0
5	Less CUSTOMER BILLINGS	16,269	-	-	-	-	-	-	16,269
6	Estimated Unbilled	-	-	-	-	-	-		-
7	Reverse Prior Month Unbilled	(13,846)	-	-	-	-	-	-	(13,846)
8	Subtotal Accrued Customer Billings	2,423	-	-	-	-	-	-	2,423
9									
10	ENDING BALANCE PRE INTEREST	(12,092)	(12,128)	(12,161)	(12,195)	(12,225)	(12,259)	(12,292)	(12,092)
11									
12	MONTH'S AVERAGE BALANCE	(13,304)	(12,128)	(12,161)	(12,195)	(12,225)	(12,259)		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15	INTEREST APPLIED	(36)	(33)	(34)	(30)	(34)	(33)		(200)
16	ENDING BALANCE	$ (12,128)	$ (12,161)	$ (12,195)	$ (12,225)	$ (12,259)	$ (12,292)	$ (12,292)	$ (12,292)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2010 THROUGH APRIL 2011
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	Demand	$ 926,593	$ 857,376	$ 682,952	$ 840,566	$ 929,224	$ 546,331	4,783,042
2	Commodity	5,058,338	11,739,108	14,563,637	12,827,802	8,270,159	4,126,912	56,585,957
3	Total Gas Costs	$ 5,984,931	$ 12,596,484	$ 15,246,589	$ 13,668,369	$ 9,199,383	$ 4,673,243	$ 61,368,998
4								
5	Lead Lag Days	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	
6	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7								
8	Working Capital Rate 1/	0.00127	0.00127	0.00127	0.00127	0.00127	0.00127	
9								
10	Total Working Capital Costs	$ 7,606	$ 16,009	$ 19,377	$ 17,371	$ 11,691	$ 5,939	$ 77,993
11								
12	Prior Period Undercollection	497,623	497,623	497,623	497,623	497,623	497,623	2,985,736
13								
14	Subtotal Gas Costs, Working Capital & Under Collection	6,490,159	13,110,116	15,763,588	14,183,362	9,708,697	5,176,805	64,432,727
15								
16	Bad Debt Rate 1/	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	
17								
18	Total Bad Debt Cost	$ 153,817	$ 310,710	$ 373,597	$ 336,146	$ 230,096	$ 122,690	$ 1,527,056

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2010 THROUGH APRIL 2011
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Total Gas Costs**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4								
5	Working Capital Rate	0.00127	0.00127	0.00127	0.00127	0.00127	0.00127	
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	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	
14								
15	**Total Bad Debt Cost**	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
SCHEDULE 7
WORKING CAPITAL & BAD DEBT COLLECTED

	FOR MONTH OF:	OffPeak Nov-10	Peak Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak May-11	Total Peak
1	**VOLUMES**									
2	**RESIDENTIAL**									
3	R-1, R-3 and R-4	2,307,067	964,421	5,926,136	8,563,005	9,375,417	8,105,526	6,095,659	2,239,567	**41,269,731**
4	R-1, R-3 and R-4 (FPO)	318,425	172,690	1,075,457	1,527,911	1,653,896	1,433,033	1,068,610	398,069	**7,329,666**
5										
6	**COMMERCIAL/INDUSTRIAL**									
7	G41 - G43	1,281,247	563,529	3,460,370	5,747,332	6,133,867	5,347,058	3,801,192	1,380,963	**26,434,311**
8	G41 - G43 (FPO)	93,959	58,291	365,039	578,735	623,313	536,188	382,327	136,389	**2,680,282**
9	G51 - G63	375,489	136,520	646,287	796,234	804,968	772,695	633,794	328,182	**4,118,680**
10	G51 - G63 (FPO)	20,830	16,154	59,433	72,120	71,234	65,468	57,540	27,907	**369,856**
11										
12	**TRANSPORTATION**									
13	G41 - G43	1,303,180	318,443	2,852,099	4,112,703	4,459,391	3,913,666	3,097,663	1,408,731	**20,162,696**
14	G51 - G63	2,368,054	63,344	2,665,425	2,657,447	2,749,119	2,746,777	2,869,372	2,228,339	**15,979,823**
15										
16	**TOTAL VOLUME**	**8,068,251**	**2,293,392**	**17,050,246**	**24,055,487**	**25,871,205**	**22,920,411**	**18,006,157**	**8,148,147**	**118,345,045**
17										
18	**WORKING CAPITAL RATES**									
19	Residential R1, R3 & R4	**-$0.0037**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	
20	Residential R1, R-3 & R4 (FPO)	**-$0.0037**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	
21	C/I Sales G41 to G43	**-$0.0037**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	
22	C/I Sales G41 to G43 (FPO)	**-$0.0037**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	
23	C/I Sales G51 to G63	**-$0.0037**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	
24	C/I Sales G51 to G63 (FPO)	**-$0.0037**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	**-$0.0051**	
25										
26	**WORKING CAPITAL COSTS COLLECTED**									
27	Residential	$ (8,536)	$ (4,919)	$ (30,223)	$ (43,671)	$ (47,815)	$ (41,338)	$ (31,088)	$ (11,422)	$ **(210,476)**
28	Residential (FPO)	(1,178)	(881)	(5,485)	(7,792)	(8,435)	(7,308)	(5,450)	(2,030)	**(37,381)**
29	C/I Sales G41 to G43	(4,741)	(2,874)	(17,648)	(29,311)	(31,283)	(27,270)	(19,386)	(7,043)	**(134,815)**
30	C/I Sales G41 to G43 (FPO)	(348)	(297)	(1,862)	(2,952)	(3,179)	(2,735)	(1,950)	(696)	**(13,669)**
31	C/I Sales G51 to G63	(1,389)	(696)	(3,296)	(4,061)	(4,105)	(3,941)	(3,232)	(1,674)	**(21,005)**
32	C/I Sales G51 to G63 (FPO)	(77)	(82)	(303)	(368)	(363)	(334)	(293)	(142)	**(1,886)**
33										
34	**SUMMER GAS COST WORKING CAPITAL COLLE(**	$ **(16,269)**	$ **(9,749)**	$ **(58,817)**	$ **(88,155)**	$ **(95,180)**	$ **(82,926)**	$ **(61,400)**	$ **(23,006)**	$ **(419,233)**
35										
36	**BAD DEBT RATES**									
37	Residential R1, R3 & R4	**$0.0192**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	
38	Residential R1 & R3 (FPO)	**$0.0192**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	
39	C/I Sales G41 to G43	**$0.0192**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	
40	C/I Sales G41 to G43 (FPO)	**$0.0192**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	
41	C/I Sales G51 to G63	**$0.0192**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	
42	C/I Sales G51 to G63 (FPO)	**$0.0192**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	**$0.0189**	
43										
44	**BAD DEBTS COLLECTED**									
45	Residential R1, R3 & R4	$ 44,296	$ 18,228	$ 112,004	$ 161,841	$ 177,195	$ 153,194	$ 115,208	$ 42,328	$ **779,998**
46	Residential R1, R-3 & R4 (FPO)	6,114	3,264	20,326 14	28,877 52	31,258 63	27,084 32	20,196 73	7,523.50	**138,531**
47	C/I Sales G41 to G43	24,600	10,651	65,400 99	108,624 57	115,930 09	101,059 40	71,842.53	26,100 20	**499,608**
48	C/I Sales G41 to G43 (FPO)	1,804	1,102	6,899 24	10,938 09	11,780 62	10,133 95	7,225 98	2,577 75	**50,657**
49	C/I Sales G51 to G63	7,209	2,580	12,214.82	15,048 82	15,213 90	14,603 94	11,978 71	6,202 64	**77,843**
50	C/I Sales G51 to G63 (FPO)	400	305	1,123 28	1,363 07	1,346 32	1,237 35	1,087 51	527 44	**6,990**
51										
52	**SUMMER BAD DEBTS COLLECTED**	$ **84,423**	$ **36,129**	$ **217,968**	$ **326,693**	$ **352,725**	$ **307,313**	$ **227,539**	$ **85,259**	$ **1,553,628**

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Schedule 8
Page 1 of 1

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

	FOR THE MONTH OF	Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Apr-11		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	[redacted]													
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TENNESSEE														
6															
7															
8															
9	City Gate Supply	[redacted]													
10															
11	Dracut Supply	[redacted]													
12															
13															
14	**CANADIAN COMMODITY**														
15	PNGTS Supply	[redacted]													
16	TOTAL PNGTS														
17															
18	BP/Northeast Gas Market	[redacted]													
19	SHELL CANADIAN														
20	NEXEN														
21	TOTAL TGP/Niagara														
22															
23	ANE Dawn-Iroquois	[redacted]													
24	ANE Union/Transgas Transporation														
25	TOTAL TGP/Iroquois Commodity														
26															
27															
28	**LNG**														
29	Distrigas (FCS 064)	[redacted]													
30															
31	LNG Vapor - P/S Plant	[redacted]													
32	LNG Injections														
33	Subtotal LNG														
34															
35															
36	**Propane**														
37	Off System Sales	[redacted]													
38	Propane Sendout - P/S Plant														
39	EN Propane - Tank Farm														
40	Total Propane														
41															
42															
43	Storage Withdrawals	[redacted]													
44															
45															
46	Hedging (Gains) Loses	[redacted]													
47															
48	Supplier Cashouts	[redacted]													
49															
50	Capacity Managed - Canadian	[redacted]													
51															
52	Taxes	[redacted]													
53															
54	Non-Firm Costs	[redacted]													
55															
56															
57	**NET COMMODITY COST**	$ 5,058,338	994,333	$ 11,739,108	1,772,490	$ 14,563,637	1,996,138	$ 12,827,802	1,641,304	$ 8,270,159	1,390,558	$ 4,126,912	687,698	$ 56,585,957	8,482,521

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ENERGY NORTH NATURAL GAS, INC

D/B/A NATIONAL GRID NH
NOVEMBER 2010 THROUGH APRIL 2011
MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-10	11/01 - 11/30	**3.25%**	30	3.2500%
Dec-10	12/01 - 012/31	**3.25%**	31	3.2500%
Jan-11	01/01 - 01/31	**3.25%**	31	3.2500%
Feb-11	02/01 - 02/28	**3.25%**	28	3.2500%
Mar-11	03/01 - 03/31	**3.25%**	31	3.2500%
Apr-11	04/01 - 04/30	**3.25%**	30	3.2500%

Local Distribution Adjustment Charge Calculation

		Sales Customers	Transporatation Customers		Reference
Residential Non Heating Rates - R-1					
Energy Efficiency Charge	$0.0498				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				
Conservation Charge (CCx)		$0.0498			
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0003				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0003			
Cost Allowance Adjustment Factor		(0.0013)			Cost Allowance Factor
Rate Case Expense Factor (RCEF)		0.0116			Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0092			RILAP Page 1
LDAC		**$0.0697**		**per therm**	
Residential Heating Rates - R-3, R-4					
Energy Efficiency Charge	$0.0498				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0498			
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0003				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0003			
Cost Allowance Adjustmern Factor		(0.0013)			Cost Allowance Factor
Rate Case Expense Factor (RCEF)		0.0116			Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0092			RILAP Page 1
LDAC		**$0.0697**		**per therm**	
Commercial/Industrial Low Annual Use Rates - G-41, G-51					
Energy Efficiency Charge	$0.0298				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0298	$0.0298		
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0003				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0003	0.0003		
Cost Allowance Adjustmern Factor		(0.0013)	0.0023		Cost Allowance Factor
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000		
Rate Case Expense Factor (RCEF)		0.0116	0.0116		Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0092	0.0092		RILAP Page 1
LDAC		**$0.0497**	**$0.0532**	**per therm**	
Commercial/Industrial Medium Annual Use Rates - G-42, G-52					
Energy Efficiency Charge	$0.0298				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0298	$0.0298		
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0003				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0003	0.0003		
Cost Allowance Adjustmern Factor		(0.0013)	0.0023		Cost Allowance Factor
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000		
Rate Case Expense Factor (RCEF)		0.0116	0.0116		Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0092	0.0092		RILAP Page 1
LDAC		**$0.0497**	**$0.0532**	**per therm**	
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54					
Energy Efficiency Charge	$0.0298				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0298	$0.0298		
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0003				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0003	0.0003		
Cost Allowance Adjustmern Factor		(0.0013)	0.0023		Cost Allowance Factor
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000		
Rate Case Expense Factor (RCEF)		0.0116	0.0116		Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0092	0.0092		RILAP Page 1
LDAC		**$0.0497**	**$0.0532**	**per therm**	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$	1,112,811
Temporary Rate Reconciliation - DG 10-017		1,130,418
Sipulation per Settlement Argument - DG 10-017		(7,776)
Reconciliation DG 08-009 and Merger Incentive DG 06-707		(143,593)
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	2,091,860
OffPeak 2011 Rate Case Expense Factor		0.0052
OffPeak 2011 Projected Volumes		36,952,643
OffPeak 2011 Rate Case Expense Collection		192,154
Total Net Rate Case Expense/Temporary Rate Reconciliation Recoverable		1,899,706
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		61,976,058
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		101,612,535
Total Volumes		163,588,592
Rate Case Expense Factor	$	0.0116

DG 06-107 Merger Settlement - Emergency Response Incentive

Emergency Response Merger Incentive

Merger Incentive - Emergency Response	$	-
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		92,474,643
Total Volumes		150,828,182
Rate Case Expense Factor	$	-

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

Ln		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 17.3300	$ 0.2741	$ 0.2265		
3	R-4 Rate at 40% of R-3	$ 6.9300	$ 0.1096	$ 0.0906		
4	Program Subsidy	$ 10.4000	$ 0.1645	$ 0.1359		
5	Average Annual Therms		572	203	775	
6						
7	Peak Period RLIAP Subsidy	$ 62.40	$ 94.13	$ 27.57	$ 184.10	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 17.3300	$ 0.2741	$ 0.2265		
11	R-4 Rate at 40% of R-3	$ 6.9300	$ 0.1096	$ 0.0906		
12	Program Subsidy	$ 10.4000	$ 0.1645	$ 0.1359		
13	Average Annual Therms		118	52	170	
14						
15	Off Peak Period RLIAP Subsidy	$ 62.40	$ 19.44	$ 7.08	$ 88.92	
16						
17	Estimated Annual Subsidy	$ 124.80	$ 113.57	$ 34.65	$ 273.02	
18						
19	Number of Estimated 2010/11 Participants				6,551	1/
20						
21	Annual Subsidy times Number of Particpants (Ln 17 * Ln 19)				$ 1,788,548	
22	Prior Year Ending Balance - RLIAP Page 2				(300,069)	
23	Estimated Annual Administrative Costs				8,600	
24	Total Program Costs				$ 1,497,079	
25						
26	Estimated weather normalized firm therms billed for					
27	the twelve months ended 10/31/11 sales and transportation				163,588,592	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0092**	

1/ Estimated number of participants for 2010-11 is based on the actual number participants as of June 2011, as provided in the RLIAP Quarterly Report as revised and filed on July 29, 2011.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
NOVEMBER 2010 THROUGH OCTOBER 2011
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

										(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (43,527)	$ (130,619)	$ (224,544)	$ (359,784)	$ (448,624)	$ (476,112)	$ (462,731)	$ (417,822)	$ (404,111)	$ (379,950)	$ (349,797)	$ (318,830)	$ (43,527)
4														
5	Add: Actual Costs	19,619	104,348	144,609	212,273	239,663	223,505	163,508	91,171	93,207	91,084	91,365	101,576	1,575,928
6														
7	Less: Collected Revenue	(106,479)	(197,783)	(279,044)	(300,106)	(265,877)	(208,871)	(117,386)	(76,363)	(67,966)	(59,925)	(59,507)	(81,961)	(1,821,268)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (130,387)	$ (224,055)	$ (358,978)	$ (447,617)	$ (474,837)	$ (461,478)	$ (416,608)	$ (403,014)	$ (378,869)	$ (348,791)	$ (317,939)	$ (299,216)	**$ (288,867)**
12														
13	Month's Average Balance	$ (86,957)	$ (177,337)	$ (291,761)	$ (403,700)	$ (461,731)	$ (468,795)	$ (439,670)	$ (410,418)	$ (391,490)	$ (364,371)	$ (333,868)	$ (309,023)	
14														
15	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16														
17	Interest Applied	$ (232)	$ (489)	$ (805)	$ (1,006)	$ (1,275)	$ (1,252)	$ (1,214)	$ (1,096)	$ (1,081)	$ (1,006)	$ (892)	$ (853)	**(11,202)**
18														
19	Ending Balance	**$ (130,619)**	**$ (224,544)**	**$ (359,784)**	**$ (448,624)**	**$ (476,112)**	**$ (462,731)**	**$ (417,822)**	**$ (404,111)**	**$ (379,950)**	**$ (349,797)**	**$ (318,830)**	**$ (300,069)**	**$ (300,069)**

00000113

Conservation Charge (CC) Factor Calculation

Conservation Charge Factors for Residential Customers (CCres)

DSM Expenses	$0	Backup Page 4 Line 7
Residential Lost Margins	$0	Backup Page 5 Line 5
Residential Conservation Reconciliation Adjustment (CCRres)	(2,957)	Backup Page 2 Line 11
Total Rate Case Expense Recoverable	($2,957)	
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	60,975,253	
Conservation Charge Factor for Residential Customers (CCres)		**$0.0000**

Conservation Charge Factors for Commercial Customers (CCcomm)

DSM Expenses	$0	Backup Page 4 Line 24
Commercial Lost Margins	$0	Backup Page 5 Line 16
Commercial Conservation Reconciliation Adjustment (CCRcomm)	(4,062)	Backup Page 2 Line 28
Total Rate Case Expense Recoverable	($4,062)	
Forecasted Annual Throughput Volumes for Commercial Customer (A:VOLcomm)	101,612,535	
Conservation Charge Factor for Commercial Customers (CCres)		**$0.0000**

2010/2011 EnergyNorth Conservation Charge Reconciliation

Line No.		Actual 2010	Actual 2010	Actual 2010	Actual 2011	Actual 2011	Actual 2011	Actual 2011	Actual 2011	Actual 2011	Actual 2011	Estimate 2011	Estimate 2011	
	Domestic Heating:	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
1	**Beginning balance**	(3,803)	($2,871)	($2,878)	($2,886)	($2,894)	($2,902)	($2,910)	($2,918)	($2,926)	($2,933)	($2,941)	($2,949)	($3,803)
2	Therms sold	1,569,461	3,695,531	6,902,047	9,967,760	10,904,734	9,430,576	7,069,973	3,540,848	1,858,289	1,340,459	1,046,982	-	57,326,660
3	Surcharge (Tariff Pg. 91)	0.0006	-	-	-	-	-	-	-	-	-	-	-	
4	Revenue collected	942	-	-	-	-	-	-	-	-	-	-	-	942
5	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Lost net rev (Pg 4 Ln.5)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Under/(over)	942	-	-	-	-	-	-	-	-	-	-	-	942
8	Pre-interest ending balance	(2,862)	(2,871)	(2,878)	(2,886)	(2,894)	(2,902)	(2,910)	(2,918)	(2,926)	(2,933)	(2,941)	(2,949)	(2,862)
9	Average monthly balance	(3,332)	(2,871)	(2,878)	(2,886)	(2,894)	(2,902)	(2,910)	(2,918)	(2,926)	(2,933)	(2,941)	(2,949)	(3,332)
10	Interest for month	(9)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(96)
11	**Month-end balance**	(2,871)	(2,878)	(2,886)	(2,894)	(2,902)	(2,910)	(2,918)	(2,926)	(2,933)	(2,941)	(2,949)	(2,957)	(2,957)
12	Interest rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
13														
14		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
15		2010	2010	2010	2011	2011	2011	2011	2011	2011	2011	2011	2011	
16	**Commercial Heating:**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
17	**Beginning balance**	(3,932)	($3,943)	($3,954)	($3,964)	($3,975)	($3,986)	($3,997)	($4,007)	($4,018)	($4,029)	($4,040)	($4,051)	($3,932)
18	Therms sold	4,136,746	6,599,040	10,048,653	13,964,571	14,841,892	13,381,852	10,841,888	6,506,762	4,668,575	3,836,338	3,416,815	-	92,243,132
19	Surcharge (Tariff Pg. 91)	-	-	-	-	-	-	-	-	-	-	-	-	
20	Revenue collected	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Lost net rev (Pg 4 Ln.16)	-	-	-	-	-	-	-	-	-	-	-	-	-
23			-											-
24	Under/(over)	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Pre-interest ending balance	(3,932)	(3,943)	(3,954)	(3,964)	(3,975)	(3,986)	(3,997)	(4,007)	(4,018)	(4,029)	(4,040)	(4,051)	(3,932)
26	Average monthly balance	(3,932)	(3,943)	(3,954)	(3,964)	(3,975)	(3,986)	(3,997)	(4,007)	(4,018)	(4,029)	(4,040)	(4,051)	(3,932)
27	Interest for month	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(130)
28	**Month-end balance**	(3,943)	(3,954)	(3,964)	(3,975)	(3,986)	(3,997)	(4,007)	(4,018)	(4,029)	(4,040)	(4,051)	(4,062)	(4,062)
29	Interest rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
30														
31		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
32		2010	2010	2010	2011	2011	2011	2011	2011	2011	2011	2011	2011	
33	**TOTAL**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
34	**Beginning balance**	($7,736)	($6,814)	($6,832)	($6,851)	($6,869)	($6,888)	($6,906)	($6,925)	($6,944)	($6,963)	($6,981)	($7,000)	($7,736)
35	Therms sold	5,706,207	10,294,571	16,950,700	23,932,331	25,746,626	22,812,428	17,911,861	10,047,610	6,526,864	5,176,797	4,463,797	-	149,569,792
36	Revenue collected	942	-	-	-	-	-	-	-	-	-	-	-	942
37	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Lost net revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Under/(over)	942	-	-	-	-	-	-	-	-	-	-	-	942
40	Pre-interest ending balance	(6,794)	(6,814)	(6,832)	(6,851)	(6,869)	(6,888)	(6,906)	(6,925)	(6,944)	(6,963)	(6,981)	(7,000)	(6,794)
41	Interest for month	(20)	(18)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(225)
42	**Month-end balance**	(6,814)	(6,832)	(6,851)	(6,869)	(6,888)	(6,906)	(6,925)	(6,944)	(6,963)	(6,981)	(7,000)	(7,019)	(7,019)
43	Interest rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	

2010/2011 EnergyNorth Conservation Charge Reconciliation

Actual Throughput

Line No.		2010 OCT	2010 NOV	2010 DEC	2011 JAN	2011 FEB	2011 MAR	2011 APR	2011 MAY	2011 JUN	2011 JUL	2011 AUG	2011 SEP	TOTAL
	Domestic Heating:													
1	Therms sold - actual	1,569,461	3,695,531	6,902,047	9,967,760	10,904,734	9,430,576	7,069,973	3,540,848	1,858,289	1,340,459	1,046,982	1,126,822	58,453,482
2	Surcharge (Tariff Pg 94)	$0.0006	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
3	Revenue - actual	942	-	-	-	-	-	-	-	-	-	-	-	942
4														
5														
6														
7	**Commercial Heating:**													
8	Therms sold - actual	4,136,746	6,599,040	10,048,653	13,964,571	14,841,892	13,381,852	10,841,888	6,506,762	4,668,575	3,836,338	3,416,815	3,720,879	95,964,011
9	Surcharge (Tariff Pg 94)	$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	5,706,207	10,294,571	16,950,700	23,932,331	25,746,626	22,812,428	17,911,861	10,047,610	6,526,864	5,176,797	4,463,797	4,847,701	154,417,493
15	Revenue - actual	942	-	-	-	-	-	-	-	-	-	-	-	942

2010/2011 EnergyNorth Conservation Charge Reconciliation

Actual Expenses

Line No.		2010 OCT	2010 NOV	2010 DEC	2011 JAN	2011 FEB	2011 MAR	2011 APR	2011 MAY	2011 JUN	2011 JUL	2011 AUG	2011 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	-	-	-	-	-	-	-	-	-	-	-	-	-

2010/2011 ENERGYNORTH LOST MARGIN SUMMARY

Residential Heating

Line No.		2010 Oct	2010 Nov	2010 Dec	2011 Jan	2011 Feb	2011 Mar	2011 Apr	2011 May	2011 June	2011 July	2011 Aug	2011 Sep	TOTAL
	Fiscal 2010													
1	Lost Vol Therms (Pg 6 Ln 29)												-	-
2	Tailblock Rate	$0.2243	$0.2243	$0.2243	$0.2243	$0.2243	$0.2243	$0.2243	$0.2243	$0.2243	$0.2265	$0.2265	$0.2265	
3	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	
5	Lost Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6														
7														
8														
9	**Commercial and Industrial:**													
10														
11	**Fiscal 2010**													
12	Lost Vol Therms (Pg 5 Ln 53)													-
13	Tailblock Rate	$0.1643	$0.1978	$0.1978	$0.1978	$0.1978	$0.1978	$0.1978	$0.1643	$0.1643	$0.1660	$0.1660	$0.1660	
14	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	57%
16	Lost Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17														
18														
19	**Total**													
20														
21	**Fiscal 2010**													
22	Lost Volume Therms	-	-	-	-	-	-	-	-	-	-	-	-	
23	Tailblock Rate													
24	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	recovery rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	57%
26	recoverable portion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ENERGYNORTH 2010/2011 LOST MARGIN CALCULATION BACKUP

Line No. **Actual tailblock margin**

Line No.		Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	
1	**Domestic Heating**	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2265	0.2265	0.2265	
2														
3	**Commercial Heating**	0.1643	0.1978	0.1978	0.1978	0.1978	0.1978	0.1978	0.1643	0.1643	0.1660	0.1660	0.1660	
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	418	704	1,050	1,231	1,042	896	512	240	50	6	11	113	6,273
9														
10	Percent of Total	6.66%	11.22%	16.74%	19.62%	16.61%	14.28%	8.16%	3.83%	0.80%	0.10%	0.18%	1.80%	100.00%
11														

Residential Heating

Line No.		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	annual load	Pg 8 Ln32 F Y 97 Savings	Pg 7 Ln31 FY98 Savings	Pg 6 Ln14 FY99 Savings	FY00 Savings	FY01 Savings
12																				
13																				
14		Therms																		
15	**program year 2010**																			
16	**DH** - therm savings fiscal																			
17	Oct-09													-	15,432	8,616	6,816	-	0	0
18	Nov-09													-	16,450	3,455	12,996	-	0	0
19	Dec-09													-	25,866	4,342	15,945	5,579	0	0
20	Jan-10													-	25,818	4,088	6,134	15,596	0	0
21	Feb-10													-	36,373	9,277	12,457	14,639	0	0
22	Mar-10													-	31,547	8,055	14,524	8,969	0	0
23	Apr-10													-	36,059	10,465	17,113	8,481	0	0
24	May-10													-	16,633	11,922	4,711	-	0	0
25	Jun-10													-	32,762	23,809	7,258	1,695	0	0
26	Jul-10													-	15,798	12,412	3,386	-	0	0
27	Aug-10													-	17,875	12,514	1,331	4,030	0	0
28	Sep-10													-	34,800	28,758	5,981	61	0	0
29	totals	-	-	-	-	-	-	-	-	-	-	-	-	-	305,409	137,710	108,649	59,050	-	-
30																				
31	Rate	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2243	0.2265	0.2265	0.2265							
32	Margin	-	-	-	-	-	-	-	-	-	-	-	-	-						
33	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
34		-	-	-	-	-	-	-	-	-	-	-	-	-						
35																				

Commercial Heating

Line No.		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	Total	Pg 8 Ln49 F Y 97 Savings	Pg 7 Ln48 FY98 Savings	FY99 Savings	FY00 Savings	FY01 Savings
36																				
37																				
38		Therms																		
39	**program year 2010**																			
40	**CH** - therm savings																			
41	Oct-09													-	189	-	189	0	0	0
42	Nov-09													-	567	378	189	0	0	0
43	Dec-09													-	1,189	439	750	0	0	0
44	Jan-10													-	945	189	756	0	0	0
45	Feb-10													-	399	189	210	0	0	0
46	Mar-10													-	945	378	567	0	0	0
47	Apr-10													-	189	-	189	0	0	0
48	May-10													-	378	-	378	0	0	0
49	Jun-10													-	1,256	567	689	0	0	0
50	Jul-10													-	549	549	-	0	0	0
51	Aug-10													-	189	189	-	0	0	0
52	Sep-10													-	1,000	-	1,000	0	0	0
53	totals													-	7,795	2,878	4,917	-	-	-
54																				
55	Rate	$0.1643	$0.1978	$0.1978	$0.1978	$0.1978	$0.1978	$0.1978	$0.1643	$0.1643	$0.1660	$0.1660	$0.1660							
56	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						
57	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
58	Total Recovery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						

00000119

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential Non Heating and Heating Classes
November 1, 2011 - October 31, 2012
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Actual DSM Expenditures Low-Income	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
May 11	Actual	(1,767,054)	($0.0525)	(189,486)	232,072	213,190	19,761	(1,723,589)	(1,745,322)	3.25%	(4,818)	(1,728,407)	2,996,052	3,612,694	31
June 11	Actual	(1,728,407)	($0.0525)	(100,415)	232,072	118,077	27,279	(1,683,465)	(1,705,936)	3.25%	(4,557)	(1,688,022)	1,933,247	1,914,481	30
July 11	Actual	(1,688,022)	($0.0525)	(72,856)	232,072	108,964	7,417	(1,644,497)	(1,666,260)	3.25%	(4,599)	(1,649,096)	1,538,140	1,389,050	31
August 11	Forecast	(1,649,096)	($0.0525)	(64,695)	491,119	0	0	(1,222,672)	(1,435,884)	3.25%	(3,963)	(1,226,636)	1,233,467	0	31
September 11	Forecast	(1,226,636)	($0.0525)	(65,109)	491,119	0	0	(800,625)	(1,013,630)	3.25%	(2,708)	(803,333)	1,241,348	0	30
October 11	Forecast	(803,333)	($0.0525)	(120,814)	491,119	0	0	(433,027)	(618,180)	3.25%	(1,706)	(434,734)	2,303,409	0	31
November 11	Forecast	(434,734)	($0.0498)	(191,487)	491,119	0	0	(135,102)	(284,918)	3.25%	(761)	(135,863)	3,848,220	0	30
December 11	Forecast	(135,863)	($0.0498)	(351,228)	491,119	0	0	4,028	(65,918)	3.25%	(182)	3,846	7,058,441	0	31
January 12	Forecast	3,846	($0.0498)	(493,047)	255,057	0	0	(234,144)	(115,149)	3.25%	(318)	(234,462)	9,908,505	0	31
February 12	Forecast	(234,462)	($0.0498)	(542,203)	255,057	0	0	(521,608)	(378,035)	3.25%	(942)	(522,551)	10,896,369	0	28
March 12	Forecast	(522,551)	($0.0498)	(483,482)	255,057	0	0	(750,976)	(636,763)	3.25%	(1,758)	(752,734)	9,716,286	0	31
April 12	Forecast	(752,734)	($0.0498)	(372,493)	255,057	0	0	(870,169)	(811,451)	3.25%	(2,168)	(872,337)	7,485,784	0	30
May 12	Forecast	(872,337)	($0.0498)	(222,506)	255,057	0	0	(839,786)	(856,061)	3.25%	(2,363)	(842,149)	4,471,593	0	31
June 12	Forecast	(842,149)	($0.0498)	(123,524)	255,057	0	0	(710,616)	(776,383)	3.25%	(2,074)	(712,690)	2,482,396	0	30
July 12	Forecast	(712,690)	($0.0498)	(77,901)	255,057	0	0	(535,534)	(624,112)	3.25%	(1,723)	(537,257)	1,565,536	0	31
August 12	Forecast	(537,257)	($0.0498)	(63,201)	255,057	0	0	(345,400)	(441,329)	3.25%	(1,218)	(346,619)	1,270,112	0	31
September 12	Forecast	(346,619)	($0.0498)	(68,074)	255,057	0	0	(159,635)	(253,127)	3.25%	(676)	(160,311)	1,368,039	0	30
October 12	Forecast	(160,311)	($0.0498)	(94,782)	255,057	0	0	(36)	(80,174)	3.25%	(221)	(257)	1,904,776	0	31
November 12	Forecast	(257)	($0.0498)	(191,487)	255,057	0	0	63,312	31,527	3.25%	84	63,397	3,848,220	0	30
December 12	Forecast	63,397	($0.0498)	(351,228)	255,057	0	0	(32,774)	15,311	3.25%	42	(32,732)	7,058,441	0	31

Estimated Residential Nonheating Conservation Charge Effective November 1, 2011 - October 31, 2012		
Beginning Balance	$	(434,734)
Program Budget Nov 11-Oct 12		3,532,809
Projected Interest		(14,404)
Projected Budget with Interest	$	3,083,671
Total Charges	**$**	**3,083,671**
Projected Therm Sales		**61,976,058**
Residential Rate		**$0.0498**
Total Charges with Interest	**$**	**3,083,671**
Projected Therm Sales		**61,976,058**
Residential Rate		**$0.0498**

Residential Non Heating Therm Sales	1%	**1,032,484**	**1,000,804**	1%
Residential Heating Therm Sales	37%	**59,255,995**	**60,975,253**	37%
C&I Therm Sales	62%	**97,732,153**	**101,612,535**	62%
Total Therms	100%	**158,020,633**	**163,588,592**	100%
		Year One Budget	Year Two Budget	
		1/01/11 - 12/31/11	**1/01/12 - 12/31/12**	
Low-Income Program Budget		**$ 730,895**	**$ 773,062**	
Other Refund		-	-	
Total Shared Budget		**$ 730,895**	**$ 773,062**	
Residential Program Budget		**$ 2,359,779**	**$ 2,550,242**	
Residential Program Incentive		**$146,238**	**$217,565**	
Total Residential Program Budget		**$ 2,506,017**	**$ 2,767,807**	
Commercial/Industrial Program Budget		**$ 3,174,772**	**$ 3,533,796**	
Commercial/Industrial Program Incentive		**$154,045**	**$95,559**	
Total Commercial/Industrial Program Budget		**$ 3,328,817**	**$ 3,629,355**	
Total Program Budget		**$ 6,565,729**	**$ 7,170,225**	
Shared Expenses Allocation to Residential		$ 278,853	$ 292,877	
Shared Expenses Allocation to C&I		452,042	480,185	
Total Allocated Shared Expenses		**$ 730,895**	**$ 773,062**	
Total Residential (including allocation of Shared Budget)		$ 2,784,870	$ 3,060,685	
Total C&I (including allocation of Shared Budget)		3,780,859	4,109,540	
Total Budget		**$ 6,565,729**	**$ 7,170,225**	

00000120

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2011 - October 31, 2012
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 11	Actual	(2,536,965)	($0.0306)	(199,107)	315,072	44,945	26,194	(2,664,933)	(2,600,949)	**3.25%**	(7,179)	(2,672,112)	5,764,699	6,506,762	31
June 11	Actual	(2,672,112)	($0.0306)	(142,858)	315,072	24,375	36,161	(2,754,435)	(2,713,274)	3.25%	(7,248)	(2,761,683)	4,285,584	4,668,575	30
July 11	Actual	(2,761,683)	($0.0306)	(117,392)	315,072	165,473	9,832	(2,703,769)	(2,732,726)	3.25%	(7,543)	(2,711,312)	3,876,710	3,836,338	31
August 11	Forecast	(2,711,312)	($0.0306)	(108,382)	544,674	0	0	(2,275,020)	(2,493,166)	3.25%	(6,882)	(2,281,902)	3,541,882	0	31
September 11	Forecast	(2,281,902)	($0.0306)	(108,338)	544,674	0	0	(1,845,566)	(2,063,734)	3.25%	(5,513)	(1,851,078)	3,540,452	0	30
October 11	Forecast	(1,851,078)	($0.0306)	(143,748)	544,674	0	0	(1,450,152)	(1,650,615)	3.25%	(4,556)	(1,454,708)	4,697,655	0	31
November 11	Forecast	(1,454,708)	($0.0298)	(203,368)	544,674	0	0	(1,113,402)	(1,284,055)	3.25%	(3,430)	(1,116,832)	6,824,433	0	30
December 11	Forecast	(1,116,832)	($0.0298)	(306,131)	544,674	0	0	(878,289)	(997,560)	3.25%	(2,754)	(881,042)	10,272,865	0	31
January 12	Forecast	(881,042)	($0.0298)	(410,734)	342,462	0	0	(949,315)	(915,179)	3.25%	(2,526)	(951,841)	13,783,033	0	31
February 12	Forecast	(951,841)	($0.0298)	(438,930)	342,462	0	0	(1,048,309)	(1,000,075)	3.25%	(2,493)	(1,050,803)	14,729,185	0	28
March 12	Forecast	(1,050,803)	($0.0298)	(405,554)	342,462	0	0	(1,113,895)	(1,082,349)	3.25%	(2,988)	(1,116,882)	13,609,208	0	31
April 12	Forecast	(1,116,882)	($0.0298)	(341,064)	342,462	0	0	(1,115,485)	(1,116,184)	3.25%	(2,982)	(1,118,466)	11,445,105	0	30
May 12	Forecast	(1,118,466)	($0.0298)	(228,719)	342,462	0	0	(1,004,724)	(1,061,595)	3.25%	(2,930)	(1,007,654)	7,675,149	0	31
June 12	Forecast	(1,007,654)	($0.0298)	(167,431)	342,462	0	0	(832,623)	(920,139)	3.25%	(2,458)	(835,081)	5,618,481	0	30
July 12	Forecast	(835,081)	($0.0298)	(129,853)	342,462	0	0	(622,472)	(728,777)	3.25%	(2,012)	(624,484)	4,357,483	0	31
August 12	Forecast	(624,484)	($0.0298)	(120,386)	342,462	0	0	(402,408)	(513,446)	3.25%	(1,417)	(403,826)	4,039,787	0	31
September 12	Forecast	(403,826)	($0.0298)	(130,115)	342,462	0	0	(191,479)	(297,652)	3.25%	(795)	(192,274)	4,366,259	0	30
October 12	Forecast	(192,274)	($0.0298)	(145,768)	342,462	0	0	4,420	(93,927)	3.25%	(259)	4,160	4,891,547	0	31
November 12	Forecast	4,160	($0.0298)	(203,368)	342,462	0	0	143,254	73,707	3.25%	197	143,451	6,824,433	0	30
December 12	Forecast	143,451	($0.0298)	(306,131)	342,462	0	0	179,782	161,616	3.25%	446	180,228	10,272,865	0	31

Estimated C & I Conservation Charge Effective November 1, 2011 - October 31, 2012	
Beginning Balance	($1,454,708)
Program Budget	4,513,965
Projected Interest	(27,044)
Program Budget with Interest	$3,032,213
Total Charges	**$3,032,213**
Projected Therm Sales	**101,612,535**
C&I Rate	$0.0298
Total Charges with Interest	**$3,032,213**
Projected Therm Sales	**101,612,535**
Com/Ind Rate	**$0.0298**
Com/Ind Rate from Prior Programs (1)	**$0.0000**
Combined Com/Ind Rate	**$0.0298**

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2011 - October 31, 2012
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Com-Ind	Low-Income	Total	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
May 11	Actual	(4,304,019)	n/a	(388,593)	547,144	213,190	44,945	45,955	304,089	(4,388,522)	(4,346,271)	**3.25%**	(11,997)	(4,400,519)	8,760,751	10,119,456	31
June 11	Actual	(4,400,519)	n/a	(243,273)	547,144	118,077	24,375	63,440	205,891	(4,437,900)	(4,419,210)	3.25%	(11,805)	(4,449,705)	6,218,831	6,583,056	30
July 11	Actual	(4,449,705)	n/a	(190,248)	547,144	108,964	165,473	17,249	291,687	(4,348,266)	(4,398,986)	3.25%	(12,142)	(4,360,408)	5,414,850	5,225,388	31
August 11	Forecast	(4,360,408)	n/a	(173,077)	1,035,793	0	0	0	0	(3,497,692)	(3,929,050)	3.25%	(10,845)	(3,508,538)	4,775,349	0	31
September 11	Forecast	(3,508,538)	n/a	(173,447)	1,035,793	0	0	0	0	(2,646,191)	(3,077,364)	3.25%	(8,220)	(2,654,411)	4,781,800	0	30
October 11	Forecast	(2,654,411)	n/a	(264,562)	1,035,793	0	0	0	0	(1,883,180)	(2,268,795)	3.25%	(6,262)	(1,889,442)	7,001,064	0	31
November 11	Forecast	(1,889,442)	n/a	(394,855)	1,035,793	0	0	0	0	(1,248,504)	(1,568,973)	3.25%	(4,191)	(1,252,695)	10,672,653	0	30
December 11	Forecast	(1,252,695)	n/a	(657,359)	1,035,793	0	0	0	0	(874,261)	(1,063,478)	3.25%	(2,935)	(877,196)	17,331,306	0	31
January 12	Forecast	(877,196)	n/a	(903,781)	597,519	0	0	0	0	(1,183,459)	(1,030,328)	3.25%	(2,844)	(1,186,303)	23,691,538	0	31
February 12	Forecast	(1,186,303)	n/a	(981,133)	597,519	0	0	0	0	(1,569,917)	(1,378,110)	3.25%	(3,436)	(1,573,353)	25,625,554	0	28
March 12	Forecast	(1,573,353)	n/a	(889,036)	597,519	0	0	0	0	(1,864,871)	(1,719,112)	3.25%	(4,745)	(1,869,616)	23,325,494	0	31
April 12	Forecast	(1,869,616)	n/a	(713,557)	597,519	0	0	0	0	(1,985,654)	(1,927,635)	3.25%	(5,149)	(1,990,803)	18,930,889	0	30
May 12	Forecast	(1,990,803)	n/a	(451,225)	597,519	0	0	0	0	(1,844,510)	(1,917,656)	3.25%	(5,293)	(1,849,803)	12,146,742	0	31
June 12	Forecast	(1,849,803)	n/a	(290,955)	597,519	0	0	0	0	(1,543,239)	(1,696,521)	3.25%	(4,532)	(1,547,771)	8,100,878	0	30
July 12	Forecast	(1,547,771)	n/a	(207,754)	597,519	0	0	0	0	(1,158,006)	(1,352,889)	3.25%	(3,734)	(1,161,741)	5,923,019	0	31
August 12	Forecast	(1,161,741)	n/a	(183,587)	597,519	0	0	0	0	(747,809)	(954,775)	3.25%	(2,635)	(750,444)	5,309,899	0	31
September 12	Forecast	(750,444)	n/a	(198,189)	597,519	0	0	0	0	(351,114)	(550,779)	3.25%	(1,471)	(352,586)	5,734,298	0	30
October 12	Forecast	(352,586)	n/a	(240,550)	597,519	0	0	0	0	4,384	(174,101)	3.25%	(481)	3,903	6,796,324	0	31
November 12	Forecast	3,903	n/a	(394,855)	597,519	0	0	0	0	206,566	105,235	3.25%	281	206,847	10,672,653	0	30
December 12	Forecast	206,847	n/a	(657,359)	597,519	0	0	0	0	147,007	176,927	3.25%	488	147,495	17,331,306	0	31

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 1, 2011 - October 31, 2012	
Beginning Balance	$ (1,889,442.13)
Program Budget	8,046,774.22
Projected Interest	(41,447.46)
Program Budget with Interest	$6,115,885
Total Charges	**$6,115,885**

New Hampshire Program Year ONE (January 1, 2011 - December 31, 2011)

Program	Internal Admin	External Admin	Rebates/ Services	Internal Impl	Marketing	Evaluation	Budget Total	Participant Goal	Lifetime MMBTU Savings
Residential									
Low Income	$ 52,000	$ 275,278	$ 397,977		$ 5,641	$ -	$ 730,895	260	70,954
Residential High-Efficiency Heating, Water-I	$ 23,067	$ 166,136	$ 475,294		$ 48,592	$ 1,375	$ 714,464	1,983	306,840
New Home Construction with Energy Star	$ 727	$ 28,628	$ 45,000		$ 5,000	$ -	$ 79,355	30	20,400
Res Building Practices and Demo	$ 1,556	$ 4,523	$ 15,000		$ 3,750	$ 500	$ 25,329	10	0
Energy Audit with Home Performance and W	$ 30,967	$ 131,244	$ 1,329,164		$ 36,534	$ 12,722	$ 1,540,631	1,200	338,400
Residential Total	**$ 108,316**	**$ 605,809**	**$ 2,262,435**	**$ -**	**$ 99,516**	**$ 14,597**	**$ 3,090,674**	**3,483**	**736,594**
Commercial & Industrial									
Large C & I Retrofit Program	$ 160,000	$ 150,000	$ 1,425,000		$ 58,625	$ 62,669	$ 1,856,294	226	699,027
New Equipment and Construction Program	$ 95,000	$ 100,000	$ 765,000		$ 34,875	$ 37,280	$ 1,032,155	307	280,381
Small Business Energy Solutions Program	$ 25,792	$ 38,688	$ 202,500		$ 9,349	$ 9,994	$ 286,323	23	111,884
Commercial Total	**$ 280,792**	**$ 288,688**	**$ 2,392,500**	**$ -**	**$ 102,849**	**$ 109,943**	**$ 3,174,772**	**556**	**1,091,292**
GRAND TOTAL	**$ 389,108**	**$ 894,497**	**$ 4,654,935**	**$ -**	**$ 202,365**	**$ 124,540**	**$ 6,265,446**	**4,039**	**1,827,886**

New Hampshire Program Year TWO (January 1, 2011 - December 31, 2011)

Program	Internal Admin	External Admin	Rebates/ Services	Internal Impl	Marketing	Evaluation	Budget Total	Participant Goal	Lifetime MMBTU Savings
Residential									
Low Income	$ 55,000	$ 291,159	$ 420,937		$ 5,966	$ -	$ 773,062	275	75,048
Residential High-Efficiency Heating, Water	$ 25,767	$ 178,054	$ 503,406		$ 51,087	$ 1,425	$ 759,739	2,137	328,375
New Home Construction with Energy Star	$ 824	$ 32,445	$ 51,000		$ 5,500	$ -	$ 89,769	34	23,120
Res Building Practices and Demo	$ 1,556	$ 4,523	$ 15,000		$ 3,750	$ 500	$ 25,329	10	0
Energy Audit with Home Performance and	$ 34,295	$ 149,166	$ 1,440,692		$ 37,623	$ 13,631	$ 1,675,406	1,400	394,800
Residential Total	**$ 117,441**	**$ 655,347**	**$ 2,431,035**	**$ -**	**$ 103,926**	**$ 15,556**	**$ 3,323,305**	**3,856**	**821,343**
Commercial & Industrial									
Large C & I Retrofit Program	$ 176,000	$ 165,000	$ 1,567,500		$ 64,488	$ 68,936	$ 2,041,924	270	769,785
New Equipment and Construction Program	$ 104,500	$ 110,000	$ 841,500		$ 38,363	$ 41,008	$ 1,135,371	371	314,735
Small Business Energy Solutions Program	$ 32,240	$ 48,360	$ 253,125		$ 10,284	$ 12,493	$ 356,502	29	141,071
Commercial Total	**$ 312,740**	**$ 323,360**	**$ 2,662,125**	**$ -**	**$ 113,134**	**$ 122,437**	**$ 3,533,796**	**670**	**1,225,591**
GRAND TOTAL	**$ 430,181**	**$ 978,707**	**$ 5,093,160**	**$ -**	**$ 217,060**	**$ 137,993**	**$ 6,857,101**	**4,526**	**2,046,934**

00000124

Exhibit-C: KeySpan Energy Delivery - NH DSM/MT Program Year Three (2008-2009): Shareholder Incentive Calculation - August 27, 2009

Program	Expenditures (Budget) for Program Year 2	Design Goal for PY 1	Projected Lifetime Therms Savings	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	$ 442,864	160 Participants	1,082,880	1,536,336	1.419	3.50	6.05	1.73			
Residential Weatherization	$ 89,557	45 Rebates	331,200	1,449,920	4.378	3.52	7.20	2.04			
Residential High Efficiency Heating	$ 271,179	500 Rebates	1,760,000	2,319,680	1.318	7.10	6.14	0.86			
Residential High Efficiency Water Heating	$ 81,708	150 Rebates	227,100	292,202	1.287	3.20	3.17	0.99			
Energy Star Windows	$ 63,008	300 Rebates	168,225	128,412	0.763	2.81	3.08	1.10			
Energy Star Residential Controls	$ 35,231	325 Rebates	254,625	560,535	2.201	6.91	12.81	1.85			
Energy Star Homes	$ 65,561	55 Participants	0	0		0.00					
Energy Analysis: Internet Audit Guide	$ 43,136	600 New Users	0.000	0.00		0.00					
Building Practices and Demo	$ 46,291	12 Projects	0.000	0.00		0.00					
Residential Conservation Services	$ 86,459	200 Participants	0.000	0.00		0.00					
Total	$ 1,224,992	2,347	3,824,030	6,287,085	1.644	3.70	5.31	1.4362	$ 80,256	$ 65,983	$ 146,238
C&I and Mutifamily											
Commercial Energy Efficiency Program	$ 542,617	150 Participants	1,647,585	746,905	0.453	2.91	1.75	0.60			
Multifamily Housing	$ 195,773	60 Participants	458,298	122,213	0.267	2.43	1.13	0.47			
Commercial High Efficiency Heating	$ 121,803	50 Rebates	996,000	4,362,480	4.380	6.44	10.36	1.61			
Economic Redevelopment	$ 330,182	3 Projects	591,396	2,562,717	4.333	2.56	29.21	11.39			
Commercial Building Practices & Tecnology Demonstration	$ 215,301	6 Projects	2,368,277	789,426	0.333	15.7	134.75	8.56			
C&I Energy Analysis Internet Audit	$ 21,122	50 New Users	0	0		0.00	0.00				
Total - C&I and Multifamily	$ 1,426,799	319	6,061,556	8,583,741	1.416	4.52	7.30	1.61	$ 80,819	$ 73,226	$ 154,045
Total of Column	$2,651,791									**TOTAL Incentive**	**$ 300,283**

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: $\text{Incentive}_{res} = \text{Expenditures}_{RES} \times \{[4\% \times (\text{TRC}_{Actual} / \text{TRC}_{Projected})] + [4\% \times \text{Lifetime Therm Savings}_{Actual} / \text{Lifetime Therm Savings}_{Projected})]\}$

Plus

$\text{Incentive}_{C\&I} = \text{Expenditures}_{C\&I} \times \{[4\% \times (\text{TRC}_{Actual} / \text{TRC}_{Projected})] + [4\% \times \text{Lifetime Therm Savings}_{Actual} / \text{Lifetime Therm Savings}_{Projected})]\}$

[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.

00000125

Exhibit D - Shareholder Incentive Page 1 of 2

National Grid Gas Energy Efficiency

Target Shareholder Incentive Year TWO- January 1, 2010 - December 31, 2010

Commercial/Industrial Incentive

1. Target Benefit/Cost Ratio	2.01
Actual Benefit/Cost Ratio	1.99
2. Threshold Benefit/Cost Ratio	1.00
3. Target lifetime MMBTU	1,236,404
Actual lifetime MMBTU	678,145
4. Threshold MMBTU	803,663
5. Budget	$2,411,290
6. CE Percentage	4.00%
7. Lifetime kWh Percentage	4.00%
8. Target C/I Incentive	**$192,903**
Actual C/I Incentive	**$95,559**
9. Cap	**$289,355**

Residential Incentive

10. Target Benefit/Cost Ratio	2.15
Actual Benefit/Cost Ratio	2.54
11. Threshold Benefit/Cost Ratio	1.00
12. Target lifetime MMBTU	885,455
Actual lifetime MMBTU	821,512
13. Threshold MMBTU	575,546
14. Budget	$2,575,126
15. CE Percentage	4.00%
16. Lifetime kWh Percentage	4.00%
17. Target Residential Incentive	**$206,010**
Actual Residential Incentive	**$217,565**
18. Cap	**$309,015**
19. TOTAL INCENTIVE	**$313,124**

NHPUC NO. 6 - GAS
KEYSPAN ENERGY DELIVERY

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual increase in rates	$56,582	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/12- sales and transportation	163,588,592	therms
Surcharge per therm	$0.0003	per therm
Total Environmental Surcharge	$0.0003	

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
Tariff page 91

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	(9/08 - 9/09) pool #10	(9/09 - 9/10) pool #11	(9/10 - 9/11) pool #11	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	128,187	143,000	249,448	6,499,859
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	128,187	143,000	249,448	6,499,859
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(2,126,793)
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)	-	(12,608)	(6,064)	(32,417)	(1,948,994)
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	115,579	136,936	217,032	4,550,865
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)	(12,620)	(12,904)	(13,145)	(13,202)	(121,263)
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	234,166	(12,904)	(13,145)	(13,202)	(3,791,029)
D Net balance to be recovered (A-B+C)	-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	203,830	759,835
E Allocation of Litigated Recovery					-		-		(329,540)	(102,675)	(123,791)	(67,710)	(623,716)
Surcharge calculation 2007/2008													
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	-	136,119	136,119
remaining life	-	-	-	-	24	36	48	60	72	84	84	84	
one year	-	-	-	-	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-		-	-	-	19,446	
Required annual increase in rates 2007/2008: smaller of D or F	-	-	-	-	-	-	-		-	-	-	19,446	19,446
forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	**163,588,592**	163,588,592
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	$0.0001	$0.0001

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
Tariff page 91

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 Incl. Audit Corr	(9/08 - 9/09) pool #8 Incl. Audit Corr	(9/09 - 9/10) pool #9	(9/10 - 9/11) pool #10	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	428,225	607,876	262,678	211,728	11,180,995
A Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	607,876	262,678	211,728	11,180,995
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	449,954	607,876	262,678	211,728	11,214,367
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	4,680,958	607,876	262,678	211,728	5,763,240
E Allocation of Litigated Recovery							(4,680,958)	(607,876)	(262,678)	(166,854)	(5,718,366)
Surcharge calculation 2007/2008											
Unrecovered costs (D+E)	-	-	-	-			-	-	-	44,874	44,874
remaining life	-	-	-	36	48	60	72	84	84	84	
one year	-	-	-	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	-	6,411	
Required annual increase in rates 2007/200 smaller of D or F	-	-	-	-	-		-	-	-	6,411	6,411
forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592
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

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.
Environmental Remediation - MGPs
Tariff page 91

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 Incl. Audit Corr	(9/08 - 9/09) pool #9	(9/09 - 9/10) pool #10	(9/10 - 9/11) pool #11	subtotal
	Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,281	9,203,246
	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	4,387,645	312,185	369,037	372,281	10,028,338
	Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(2,168,336)
	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)	-	(40,359)	(234,648)	(923,464)
A-B	Total net expenses to recover	495,106	329,986	-	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,633	9,104,874
	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	6,486,145	312,185	328,678	137,633	7,264,641
E	Allocation of Litigated Recovery			-	-	-			(6,486,145)	(312,185)	(328,678)	(135,468)	(7,262,476)
	Surcharge calculation 2007/2008												
	Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-	2,166	2,166
	remaining life	-	-	-	24	36	48	60	70	84	84	84	
	one year	-	-	-	12	12	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	-	-	-	309	
	Required annual increase in rates 2007/200												
	smaller of D or F	-	-	-	-	-	-		-	-	-	309	309
	forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592
	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.

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

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

	Nashua											
							Corrected per 2/08 Audit					
	(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**	**(9/06 - 9/07) pool #7**	**(9/07 - 9/08) pool #8**	**(9/08 - 9/09) pool #9**	**(9/09 - 9/10) pool #9**	**(9/10 - 9/11) pool #10**	**subtotal**
Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,166	664,333
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	78,535	162,729	65,166	2,435,900
												-
Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(190,913)
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)	(62,246)	(63,753)	(31,767)	(172,525)
												-
A-B Total net expenses to recover	1,233,726	362,663	175,178	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,399	2,263,375
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	16,289	98,975	33,399	790,869
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	(16,289)	(98,975)	(33,676)	(791,146)
Surcharge calculation 2007/2008												
Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-	(277)	(277)
remaining life	-	-	12	24	36	48	60	72	84	84	84	
one year	-	12	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	-	-	(40)	
Required annual increase in rates 2007/200												
smaller of D or F	-	-	-	-	-	-		-	-	-	(40)	(40)
forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592
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.

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.
Environmental Remediation - MGPs
Tariff page 91

	Dover								
	(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 #5**	**(9/08 - 9/09) pool #6**	**(9/09 - 9/10) pool #7**	**(9/10 - 9/11) pool #8**	**subtotal**
Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	-	-	21,142
Remediation costs (i.o. 500005)	181,066								181,066
A Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	-	-	202,208
Cash recoveries (i.o. 500061)	-					-	-	-	-
Cash recoveries (i.o. 500004)	-								-
Recovery costs (i.o. 500004)	-								-
Transfer Credit from Gas Restructuring									-
B Subtotal - net recoveries	-	-	-	-	-	-	-	-	-
A-B Total net expenses to recover	181,066	18,854	2,288	-	-	-	-	-	202,208
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)
Actual November 2007- October 2008									-
AES collections									-
Gas Street overcollection									-
Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-	-	-	
C Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	-	-	(113,174)
D Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	-	-	89,034
E Allocation of Litigated Recovery		-		-	(89,034)	-	-	-	(89,034)
Surcharge calculation 2007/2008									
Unrecovered costs (D+E)	-	-	-		-	-	-	-	-
remaining life	24	36	48	60	72	84	84	84	
one year	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	
Required annual increase in rates 2007/200 smaller of D or F	-	-	-		-	-	-	-	-
forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592
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.

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
Tariff page 91

		Keene								
		(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	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	(9/10 - 9/11) pool #8	subtotal
	Remediation costs (i.o. 500061)	-								-
	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	60,949
A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	60,949
										-
	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	10,165	6,606	53,942	9,589	32	269	-	-	80,604
										-
										-
	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	-	-	(14,091)						(14,091)
Actual	November 2007- October 2008									-
	AES collections									-
	Gas Street overcollection									-
	Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	
C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	(14,091)
D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	66,513
										-
E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	(66,513)
										-
	Surcharge calculation 2007/2008									-
	Unrecovered costs (D+E)	-	-	-			-	-	-	-
	remaining life	24	36	48	60	72	84	84	84	
	one year	12	12	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	-	
	Required annual increase in rates 2007/200									
	smaller of D or F	-	-	-			-	-	-	-
	forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592
	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.

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
Tariff page 91

		Concord								
				Corrected per 1/24/07 Audit	Corrected per 2/08 Audit					
		(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**	**(9/08 - 9/09) pool #6**	**(9/09 - 9/10) pool #7**	**(9/10 - 9/11) pool #8**	**subtotal**
	Remediation costs (i.o. 500061)	-								-
	Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	77,063	49,403	180,032	711,614
A	Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	77,063	49,403	180,032	711,614
										-
	Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(80,801)
	Cash recoveries (i.o. 500004)	-								-
	Recovery costs (i.o. 500004)					1,432	(1,007)			425
	Transfer Credit from Gas Restructuring			-						-
B	Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(80,376)
A-B	Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	92,679	46,190	168,638	631,238
										-
										-
	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	92,679	46,190	168,638	575,557
										-
E	Allocation of Litigated Recovery	-	-	-	-	(268,051)	(92,679)	(46,190)	(9,392)	(416,311)
										-
	Surcharge calculation 2007/2008									-
	Unrecovered costs (D+E)	-	-	-		-	-	-	159,246	159,246
	remaining life	36	48	60		72	84	84	84	
	one year	12	12	12		12	12	12	12	
F	amortization 2007/2008	-	-	-		-	-	-	22,749	
	Required annual increase in rates 2007/200									
	smaller of D or F	-	-	-		-	-	-	22,749	22,749
	forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001

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

00000134

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
Tariff page 91

	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**	**(9/08 - 9/09) pool #7**	**(9/09 - 9/10) pool #8**	**(9/10 - 9/11) pool #9**	**subtotal**			**2011 MGP Remediation subtotal**
Remediation costs (i.o. 500061)	-									-			16,388,580
Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	672,212			15,403,494
A Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	672,212			31,792,074
Cash recoveries (i.o. 500061)	-				-	-	-			-			(4,566,842)
Cash recoveries (i.o. 500004)	-									-			(445,985)
Recovery costs (i.o. 500004)				290,155	31,826	16,012	23,953			361,946			2,302,441
Transfer Credit from Gas Restructuring	(3,331)			-						(3,331)			(3,331)
B Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	23,953	-	-	358,615			(2,713,717)
A-B Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	(2,931)	4,199	69,286	1,030,827			29,078,357
													29,078,357
													-
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		-								-			(121,263)
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)		(13,068,248)	(13,068,248)
D Net balance to be recovered (A-B+C)	(8,388)	313,370	465,817	741,010	794,853	629,865	(2,931)	4,199	69,286	700,419	824,514	16,010,109	16,010,109
											-		
E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	2,931	(4,199)	(15,337)	(646,470)	(428,437)	(15,614,032)	(15,614,032)
											-		
Surcharge calculation 2007/2008											-		409,279
Unrecovered costs (D+E)	-	-	-	-		-	-	-	53,949	53,949	396,077	396,077	
remaining life		36	48	60	72	84	84	84	84				
one year		12	12	12	12	12	12	12	12				
F amortization 2007/2008		-	-	-	-	-	-	-	7,707		56,582		
Required annual increase in rates 2007/200													
smaller of D or F	-	-	-	-		-	-	-	7,707	7,707	56,582	56,582	
forecasted therm sales	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592	163,588,592			**163,588,592**
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			**$0.0003**

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

000001135

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
Tariff page 91

Cash Recoveries[1]

														Corrected per 1/24/07 Audit		
		(9/09 - 9/10) Concord Pond	**(9/08 - 9/09) Concord Pond**	**(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**	**(9/10 - 9/11) Laconia**	**(9/09 - 9/10) Laconia**	**(9/08 - 9/09) Laconia**	**(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 2007/200															
	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.

00000136

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
Tariff page 91

	(9/10 - 9/11) Manchester	**(9/09 - 9/10) Manchester**	**(9/08 - 9/09) Manchester**	**(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**	**(9/10 - 9/11) Nashua**	**(9/09 - 9/10) Nashua**	**(9/08 - 9/09) Nashua**	**(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)			9,679	-	(630,000)	(1,725,792)	(754,938)	-	-	-		(1,032,186)	(544,402)	(625,000)	(782,450)	(795,000)
Recovery costs (i.o. 500004)	-	-	(2,008,365)	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	-	-	(1,998,686)	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	-	-	(1,998,686)	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)	-	-	(1,998,686)	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 2007/200																
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.

00000137

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
Tariff page 91

filed under the
Order No.
Order No.

EnergyNorth N
Environmental
Tariff page 91

		(9/10 - 9/11) Dover	(9/09 - 9/10) Dover	(9/08 - 9/09) Dover	(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	(9/10 - 9/11) Keene	(9/09 - 9/10) Keene
	Remediation costs (i.o. 500061)	-	-	-	-		-	-		-	
	Remediation costs (i.o. 500005)	-	-	-	-		-	-			
A	Subtotal - remediation costs	-	-	-	-		-	-			
	Cash recoveries (i.o. 500061)										
	Cash recoveries (i.o. 500004)	-	-	-	(2,133)	-	(237,489)	(7,150)	(645,500)	-	-
	Recovery costs (i.o. 500004)			(92,947)	-	14,848	117,621	517,891	500,868		
	Transfer Credit from Gas Restructuring										
B	Subtotal - net recoveries	-	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	-	-
A-B	Total net expenses to recover	-	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	-	-
	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)	-	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	-	-
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 2007/200										
	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.

00000138

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

latural Gas, Inc.
l Remediation - MGPs

		(9/08 - 9/09) Keene	(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	2011 subtotal	MGP TOTAL
	Remediation costs (i.o. 500061)				-	-			-	16,388,580
	Remediation costs (i.o. 500005)				-	-			-	15,403,494
A	Subtotal - remediation costs				-	-			-	31,792,074
	Cash recoveries (i.o. 500061)								-	(4,566,842)
	Cash recoveries (i.o. 500004)	116			(700,000)	(211,213)	0	(10,760,900)	(22,792,408)	(23,238,393)
	Recovery costs (i.o. 500004)		1,559	28,211	309,618	56,392	121,018		7,178,376	9,480,817
	Transfer Credit from Gas Restructuring								-	(3,331)
B	Subtotal - net recoveries	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	(18,327,749)
									-	-
A-B	Total net expenses to recover	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	13,464,325
	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								-	(121,263)
	Gas Street overcollection								-	(23,511)
	Prior Period Pool under/overcollection								-	
									-	
C	Surcharge Subtotal			-	-	-	-		-	(13,068,248)
									-	
									-	
D	Net balance to be recovered (A-B+C)	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	396,077
E	Allocation of Litigated Recovery								15,614,032	
	Surcharge calculation 2007/2008									
	Unrecovered costs (D+E)								-	
	remaining life									
	one year									
F	amortization 2007/2008									
	Required annual increase in rates 2007/200									
	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.

00000139

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
Tariff page 91

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)	(9/08 - 9/09)	(9/09 - 9/10)	(9/10 - 9/11)	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	4,590,624	518,907	674,766	686,896	16,388,580
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	255,263	658,324	316,280	461,046	15,403,494
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	4,845,887	1,177,231	991,045	1,147,942	31,792,074
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(4,566,842)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	(23,238,393)
Recovery costs (i.o. 500004)	623,784	-	-	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	9,480,817
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)	(2,126,802)	(113,390)	(310,226)	(18,327,749)
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)	3,340,669	(949,571)	877,655	837,716	13,464,325
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)	(12,620)	(12,904)	(13,145)	(13,202)	(121,263)
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)	(12,620)	(12,904)	(13,145)	(13,202)	(13,068,248)
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)	3,328,049	(962,475)	864,510	824,514	396,077
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 2007/200																
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.

00000140

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

CONCORD FORMER MGP

LINE
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 Exit 13 pond remedy, and determine if additional treatment may be necessary. A groundwater sampling round for the MGP site was conducted in August 2010 and included monitoring wells located on the MGP site itself as well as a number of wells located offsite. **In addition, a Supplemental Data Collection Work Plan for the collection of off-ENGI-owned property data was submitted to NHDES in August 2010. ENGI participated in a site walk in July 2011 with NHDES to review the supplemental investigation locations proposed in the August 2010 Work Plan.**

   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 ENGI requesting submission of a schedule and scope of work for a site investigation of the MGP site by mid-September 2003. ENGI proposed a May 2005 date for submission of a Site Investigation Report for the MGP site 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 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report was submitted to NHDES in September 2009. ENGI met with NHDES to discuss the report findings and strategy for moving forward in October 2009. NHDES issued an approval letter for the Supplemental Site Investigation Report on February 9, 2010. The correspondence approved the report and requested that certain additional activities be completed by ENGI. These requested activities include the following: a) preparation and submission of an Initial Response Action Work Plan to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots and tar wells at the MGP property on Gas Street; b) evaluation of the groundwater conditions in the vicinity of the “Tar Pond” which is depicted on a referenced NHDOT site plan; and c) evaluation of potential indoor air impacts at select locations identified during the additional SSI work.

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 **and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of**

the Work Plan on September 16, 2010. Access negotiations with various property owners are on-going and the work is expected to be implemented in the second half of 2011.

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 were to be used to prepare the Remedial Action Plan (RAP) 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. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. **ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location. ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. The City is currently evaluating the draft design plans, and has committed to following up with ENGI following their internal discussions.**

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. The issues associated with this well will be included in the overall site strategy.

LINE
NO.

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. A Site Investigation Report will be submitted for the river portion of the site; however, based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river.

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 undertook 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, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI. **ENGI met with these parties on several occasions in the last twelve months to discuss the proposed remedy and the required access.**

In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 **and the work was completed in June 2011. The NHDES-approved investigation activities are anticipated to be completed in the second half of 2011.**

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. **REDACTED**
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
KEYSPAN PROJECT DEF077

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	City of Concord	2011-50460109	600.00			600.00
	Clean Harbors Environmental Services	NH1089149	1,256.44			1,256.44
	Clean Harbors Environmental Services	NH1081934	7,252.26			7,252.26
	Clean Harbors Environmental Services	SB1190896	2,331.99			2,331.99
	Clean Harbors Environmental Services	SB1149158	80,506.77			80,506.77
	GZA GeoEnvironmental, Inc.	0629907	3,045.41			3,045.41
	GZA GeoEnvironmental, Inc.	0624332	6,209.15			6,209.15
	GZA GeoEnvironmental, Inc.	0634893	1,317.89			1,317.89
	GZA GeoEnvironmental, Inc.	0635354	4,862.25			4,862.25
	GZA GeoEnvironmental, Inc.	0635358	23,105.71			23,105.71
	GZA GeoEnvironmental, Inc.	0635362	261.71			261.71
	GZA GeoEnvironmental, Inc.	0637639	23,856.24			23,856.24
	GZA GeoEnvironmental, Inc.	0642658	17,689.02			17,689.02
	NH Department of Environmental Services	198904063	6,003.21			6,003.21
	NH Department of Environmental Services	198904063	331.91			331.91
	[redacted]					
	Total Pool Activity		**178,629.96**	**1,402.31**	**(11,394.01)**	**168,638.26**

00000146

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

REDACTED

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	City of Concord	994	1,440.00			1,440.00
	Clean Harbors Environmental Services	NH1073450	1,212.88			1,212.88
	Clean Harbors Environmental Services	NH1137669	706.28			706.28
	GEI Consultants	51438	6,292.99			6,292.99
	GEI Consultants	51548	49,542.08			49,542.08
	GEI Consultants	51666	2,937.02			2,937.02
	GEI Consultants	51869	24,825.70			24,825.70
	GEI Consultants	51992	23,744.65			23,744.65
	GEI Consultants	52200	20,193.33			20,193.33
	GEI Consultants	52307	21,683.20			21,683.20
	GEI Consultants	52462	22,645.13			22,645.13
	GEI Consultants	52645	19,194.60			19,194.60
	GEI Consultants	52694	2,267.20			2,267.20
	GEI Consultants	52992	10,792.46			10,792.46
	GEI Consultants	53151	14,594.38			14,594.38
	McLane	2010071185	613.70			613.70
	NH Department of Environmental Services	199212014	5,767.87			5,767.87
	NH Department of Environmental Services	199212014	2,346.03			2,346.03
	[redacted]					
	Total Pool Activity		**230,799.50**	**18,648.95**	**(32,416.85)**	**217,031.60**

00000147

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

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

Total Pool Activity											

00000148

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 were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River. 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 RAP Addendum 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 submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modeling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. **In October 2010, NHDES issued a Preliminary Decision on RAP Addendum No. 2, in which NHDES indicated that it did not concur with ENGI's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. On January 28, 2011, ENGI submitted a comment letter to NHDES further explaining its rationale for the remedial alternative recommended in RAP Addendum No. 2. ENGI is awaiting a Final Decision from NHDES on the RAP Addendum No. 2 and anticipates receiving the decision in the Summer of 2011.**

ENGI has also performed numerous other activities requested by NHDES between 2008 and 2011, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan; evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; semi-annual groundwater and surface water sampling activities; and drinking water well sampling. Groundwater sampling is reported to the

NHDES in semi-annual reports. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

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 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.

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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 PROJECT DEF086

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	McLane	2010071182	1,194.40			1,194.40
	GEI Consultants	51437	772.89			772.89
	McLane	2010080806	2,253.50			2,253.50
	GEI Consultants	51547	1,413.86			1,413.86
	Ostrow & Partners	08 10 01	636.00			636.00
	McLane	2010090611	469.30			469.30
	Blue Chip Films	00924	400.00			400.00
	GEI Consultants	51640	20,253.54			20,253.54
	Ostrow & Partners	01 11 01	557.75			557.75
	Public Service of New Hampshire	56285690020	11.60			11.60
	McLane	2010110659	6,815.49			6,815.49
	GEI Consultants	51868	12,867.75			12,867.75
	Ostrow & Partners	11 10 01	1,575.00			1,575.00
	GEI Consultants	51991	7,788.25			7,788.25
	McLane	2010060341	3,393.40			3,393.40
	McLane	2010120354	6,021.26			6,021.26
	Ostrow & Partners	12 10 01	1,262.00			1,262.00
	GEI Consultants	52185	5,507.75			5,507.75
	Ostrow & Partners	10 10 01	557.75			557.75
	GZA GeoEnvironmental, Inc.	0635602	7,737.99			7,737.99
	McLane	2011010503	5,223.30			5,223.30
	McLane	2011020720	16,109.90			16,109.90
	GEI Consultants	52297	3,164.59			3,164.59
	Ostrow & Partners	02 11 01	1,898.00			1,898.00
	Public Service of New Hampshire	56236690095	30.25			30.25
	Public Service of New Hampshire	56285690020	35.15			35.15
	McLane	2011031034	380.20			380.20
	McLane	2011031812	2,466.30			2,466.30
	GZA GeoEnvironmental, Inc.	0637228	737.10			737.10
	GEI Consultants	52461	15,052.12			15,052.12
	Ostrow & Partners	03 11 01	557.75			557.75
	GZA GeoEnvironmental, Inc.	0637976	1,391.40			1,391.40
	Public Service of New Hampshire	56285690020	23.55			23.55
	Public Service of New Hampshire	56236690095	50.84			50.84
	Public Service of New Hampshire	56285690020	11.60			11.60
	Public Service of New Hampshire	56236690095	38.78			38.78
	GEI Consultants	52693	3,883.97			3,883.97
	GEI Consultants	52644	22,499.61			22,499.61
	Ostrow & Partners	04 11 01	714.25			714.25
	NH Department of Environmental Services	200411113	23,912.02			23,912.02
	NH Deparment of Environmental Services	200411113	5,474.72			5,474.72
	GZA GeoEnvironmental, Inc.	0639930	5,991.07			5,991.07
	McLane	2011040556	783.80			783.80
	McLane	20110603223	291.20			291.20
	McLane	2011050846	2,495.00			2,495.00
	GZA GeoEnvironmental, Inc.	0640354	458.15			458.15
	Ostrow & Partners	05 11 01	479.50			479.50
	Ostrow & Partners	06 11 01	557.75			557.75
	GEI Consultants	52991	12,113.35			12,113.35
	Clean Harbors Environmental Services	NH1128830	727.26			727.26
	Public Service of New Hampshire	56285690020	11.60			11.60
	Public Service of New Hampshire	56285690020	23.32			23.32
	McLane	2011070660	952.00			952.00
	GEI Consultants	53150	1,694.15			1,694.15
	Public Service of New Hampshire	56236690095	4.75			4.75
	Total Pool Activity		**211,727.78**	**-**	**-**	**211,727.78**

00000154

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

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity										

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF087

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

Total Pool Activity	

00000156

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.

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, on behalf of ENGI, submitted a summary report to NHDES in January 2001 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.

- 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 from April 2003 until the regular meetings ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided 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.

LINE
NO.

- 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, portions of Singer Park at depth and the Merrimack River sediment. Further investigations were recommended by ENGI to further assess 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 Remedial Action Plans for the upland and Merrimack River portions of the site were 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 RAPs 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.

- Certain pre-design investigations were completed on the upland portion of the site in 2008/2009. ENGI also completed interim Phase I Corrective Actions at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale dense non-aqueous phase (DNAPL) recovery, and design for repair/replacement of a deteriorated portion of the site drainage system located within a known LNAPL area of the site. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedences in shallow soils.

- ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the former MGP site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements. **Groundwater monitoring events to support this GMZ permit have been ongoing.**

- ENGI submitted an RAP for the upland portion of the site to NHDES on June 30, 2010. The remedial objectives for the site include control of mobile DNAPL, reduction in contaminant mass (where practicable), and management of residual contamination through the use of administrative controls. The recommended remedial alternative includes removal of the contents of certain subsurface structures where removal is anticipated to provide a reduction in the potential for the further release of DNAPL to the subsurface; NAPL recovery from the subsurface; construction of a barrier wall proximate to the Merrimack River to mitigate potential DNAPL migration; and use of administrative controls to address potential human exposure to residual soil and groundwater contamination. Additional investigation activities were recommended to support the preparation of Design Plans and Construction Specifications following NHDES approval of the RAP and to confirm the appropriateness of certain remedial alternatives recommended in the RAP.

- **In Fall 2010, ENGI performed storm drain rehabilitation activities on a deteriorated portion of the site drainage system that is located within a known LNAPL area. This work was performed to mitigate the migration of LNAPL to the Merrimack River via the storm drain system. These activities were mainly completed in late 2010.**

- **In April 2011, NHDES approved of the upland RAP and requested that ENGI proceed with the additional investigation activities recommended in the June 2010 RAP. In addition, ENGI was contacted by both the developer and condominium association associated with the property directly downgradient of the site regarding potential impacts to the property, as well as the proposed remedy; ENGI met with both parties in early and mid-2011. ENGI is currently planning for implementation of the approved investigation activities**

LINE
NO.

and expects that the work will be performed in stages between late 2011 and early 2012.

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 (RAP) 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 RAP for the upland portion of the site was submitted to NHDES for review on June 30, 2010. **NHDES issued its approval of the RAP for the upland portion of the site in a letter dated April 11, 2011**

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 complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier paid ENGI's attorneys fees incurred in the litigation. 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

LINE
NO.

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. **REDACTED**
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
KEYSPAN PROJECT DEF057

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Clean Harbors Environmental Services	NH1128827	839.97			839.97
	Clean Harbors Environmental Services	NH1094867	278.00			278.00
	Clean Harbors Environmental Services	NH1032308	5,543.30			5,543.30
	Clean Harbors Environmental Services	NH1049062R	780.85			780.85
	Clean Harbors Environmental Services	NH1067309R	3,957.33			3,957.33
	Clean Harbors Environmental Services	NH1049063	5,349.00			5,349.00
	Clean Harbors Environmental Services	NH1080181	3,889.62			3,889.62
	Clean Harbors Environmental Services	NH1075747	5,186.42			5,186.42
	Clean Harbors Environmental Services	NH1084977	590.07			590.07
	Clean Harbors Environmental Services	NH1105219	154.78			154.78
	ESMI of NH	1007517	16,847.24			16,847.24
	ESMI of NH	1007562	4,412.32			4,412.32
	ESMI of NH	1007637	347.75			347.75
	GZA GeoEnvironmental, Inc.	0630027	66,461.56			66,461.56
	GZA GeoEnvironmental, Inc.	0634006	2,685.63			2,685.63
	GZA GeoEnvironmental, Inc.	0634028	17,934.97			17,934.97
	GZA GeoEnvironmental, Inc.	0634906	15,723.90			15,723.90
	GZA GeoEnvironmental, Inc.	0637706	5,269.36			5,269.36
	GZA GeoEnvironmental, Inc.	0641289	34,640.05			34,640.05
	GZA GeoEnvironmental, Inc.	0642748	18,734.44			18,734.44
	McLane	2010071181	830.30			830.30
	McLane	2010080804	1,191.30			1,191.30
	McLane	2011020719	1,371.80			1,371.80
	McLane	2011031033	3,779.40			3,779.40
	McLane	2011040555	858.20			858.20
	McLane	2011060322	2,256.80			2,256.80
	McLane	2011050845	5,101.10			5,101.10
	NH Department of Environmental Services	200003011	869.23			869.23
	NH Department of Environmental Services	200003011	3,816.39			3,816.39
	Shaw Environmental, Inc.	520470-R8-00501	4,372.30			4,372.30
	Shaw Environmental, Inc.	523408-R8-00501	809.06			809.06
	Shaw Environmental, Inc.	549138-R8-00501	681.66			681.66
	Shaw Environmental, Inc.	552275-R8-00501	316.00			316.00
	T Ford Company, Inc.	1	85,954.50			85,954.50
	T Ford Company, Inc.	2	33,222.01			33,222.01
	T Ford Company, Inc.	3	10,000.00			10,000.00
	T Ford Company, Inc.	5	5,924.19			5,924.19
	URS Corporation	4394348	1,300.16			1,300.16
	[redacted]					
	Total Pool Activity		**372,280.96**	**-**	**(234,647.64)**	**137,633.32**

00000163

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

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	NO ACTIVITY FOR THIS PERIOD										-
	Total Pool Activity		-	-	-	-	-	-	-	-	-

00000164

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 National Grid (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 the 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 later 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.

LINE
NO.

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

- NHDES approved the Revised Phase II Work Plan for the 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.

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

LINE
NO.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH 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 the advancement of river borings and collection of sediment samples as well as the installation of borings and monitoring wells 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 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 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 2011.

- 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 proposed and verbal approval was obtained from NHDES on November 19, 2001.

LINE
NO.

- 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 permit was issued in September 2004. The capping and re-armoring was

LINE
NO.

completed in October 2004 and the Remedial Completion Report, submitted to NHDES in January 2005, was 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 the requested 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 completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

- In Spring 2009, ENGI began trenching and final system installation activities for the DNAPL recovery pilot testing. The trenching, pump installations and system electrical work were completed in July 2009. Electrical service was installed in late August 2009. The system was started up in November 2009 and has been operational since that time. **The system has recovered 170 gallons of DNAPL through July 2011.**

- **In September 2010, ENGI submitted an Installation Summary and DNAPL Recovery Pilot test summary report to NHDES. This report recommended that DNAPL extraction activities continue. In October 2010, a work plan for an off-site groundwater investigation program to support the delineation of a Groundwater Management Zone was submitted to NHDES. This work plan was approved by NHDES in a letter dated November 5, 2010. Access negotiations and environmental permitting for the NHDES-approved investigation were completed in June 2011. The monitoring well drilling**

LINE
NO.

program is expected to begin the last week of August 2011 and groundwater sampling will occur shortly thereafter.

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 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

LINE
NO.

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 and guidance on the proper manner in which costs are to be allocated among insurers (discussed in more detail in the Manchester MGP summary) will be used in the calculation of 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. **REDACTED**
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
KEYSPAN PROJECT DEF054

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
	Clean Harbors Environmental Services	SB1034112	700.84			700.84
	Environmental Staff Time (refer to labor spreadsheet		8,797.99			8,797.99
	Innovative Engineering Solutions, Inc.	8643	7,927.14			7,927.14
	Innovative Engineering Solutions, Inc.	8861	2,542.50			2,542.50
	Innovative Engineering Solutions, Inc.	8783	2,864.06			2,864.06
	Innovative Engineering Solutions, Inc.	8717	6,862.23			6,862.23
	Innovative Engineering Solutions, Inc.	8934	4,629.72			4,629.72
	Innovative Engineering Solutions, Inc.	8996	3,995.05			3,995.05
	Innovative Engineering Solutions, Inc.	9085	3,404.06			3,404.06
	Innovative Engineering Solutions, Inc.	9231	2,409.30			2,409.30
	Innovative Engineering Solutions, Inc.	9217	5,372.26			5,372.26
	Innovative Engineering Solutions, Inc.	9301	3,526.25			3,526.25
	Innovative Engineering Solutions, Inc.	9372	3,448.96			3,448.96
	Innovative Engineering Solutions, Inc.	9439	933.27			933.27
	McLane	2010120353	1,155.20			1,155.20
	McLane	2011010502	108.30			108.30
	McLane	2010110658	2,238.20			2,238.20
	McLane	2010090609	649.80			649.80
	NH Department of Environmental Services	199810022	959.30			959.30
	NH Department of Environmental Services	199810022	2,641.69			2,641.69
	[redacted]					
	Total Pool Activity		**65,166.12**	**-**	**(31,767.31)**	**33,398.81**

00000172

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

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
Total Pool Activity			-	-	-	-	-	-	-	-	-

NO ACTIVITY FOR THIS PERIOD

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

   - 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.

LINE
NO.

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

- 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 are complete, and resulted in several confidential settlements as well as a judgment in favor of coverage. 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. 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.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABL E EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
Total Pool Activity											

NO ACTIVITY FOR THIS PERIOD

00001177

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

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	NO ACTIVITY FOR THIS PERIOD										
	Total Pool Activity		-	-	-	-	-	-	-	-	-

00000178

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 February 2007 NHDES requested the preparation of a Remedial Action Plan (RAP) for Mill Creek and a portion of the Ashuelot River. NHDES files indicate that PSNH submitted the RAP in 2008 and completed permitting and obtaining access from private property owners for the Mill Creek and Ashuelot River remediation activities in 2010. Subsequently, a remedial contractor was a selected, and

LINE
NO.

Phase II RAP implementation is underway. **According to NHDES files, remedial actions in the Mill Creek and Ashuelot River continued in 2011. In addition, the tri-annual groundwater monitoring program/reporting to NHDES continued in 2011.**

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 and that NHDES commented and approved the Phase II RAP. NHDES and other public information sources indicate that remedial and wetland permitting is complete, necessary approvals and site access agreements with impacted landowners are complete, a remedial contractor has been selected, and Phase II RAP implementation is on-going. PSNH has taken the lead on investigation at this Site, and has conducted this work 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. The case is currently stayed. 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

LINE
NO.

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.

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.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity										

NO ACTIVITY FOR THIS PERIOD

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

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

	Total Pool Activity										

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

REDACTED

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Curry Printing	185316	1,188.65			1,188.65
	Curry Printing	185935	467.70			467.70
	Curry Printing	185692	271.86			271.86
	Environmental Staff Time (refer to labor spreadsheet)		100,730.56			100,730.56
	GZA GeoEnvironmental, Inc.	0633192	7,200.00			7,200.00
	GZA GeoEnvironmental, Inc.	0634895	1,649.08			1,649.08
	Interest Expense Passback on Overcollection		(74.00)			(74.00)
	McLane	2010071184	506.00			506.00
	McLane	2010080805	3,091.15			3,091.15
	McLane	2010090610	216.60			216.60
	Pro Unlimited (refer to spreadsheet)		779.19			779.19
	Pro Unlimited (refer to spreadsheet)		280.16			280.16
	Pro Unlimited (refer to spreadsheet)		555.75			555.75
	Pro Unlimited (refer to spreadsheet)		703.52			703.52
	Pro Unlimited (refer to spreadsheet)		42.75			42.75
	Pro Unlimited (refer to spreadsheet)		427.50			427.50
	Pro Unlimited (refer to spreadsheet)		769.50			769.50
	Pro Unlimited (refer to spreadsheet)		456.00			456.00
	Pro Unlimited (refer to spreadsheet)		1,026.00			1,026.00
	Pro Unlimited (refer to spreadsheet)		342.00			342.00
	Pro Unlimited (refer to spreadsheet)		491.63			491.63
	Pro Unlimited (refer to spreadsheet)		598.50			598.50
	Pro Unlimited (refer to spreadsheet)		612.75			612.75
	Pro Unlimited (refer to spreadsheet)		85.50			85.50
	Pro Unlimited (refer to spreadsheet)		57.00			57.00
	Pro Unlimited (refer to spreadsheet)		285.00			285.00
	Pro Unlimited (refer to spreadsheet)		327.75			327.75
	Pro Unlimited (refer to spreadsheet)		527.25			527.25
	Pro Unlimited (refer to spreadsheet)		57.00			57.00
	Pro Unlimited (refer to spreadsheet)		57.72			57.72
	Pro Unlimited (refer to spreadsheet)		28.86			28.86
	Pro Unlimited (refer to spreadsheet)		28.86			28.86
	Pro Unlimited (refer to spreadsheet)		72.15			72.15
	Pro Unlimited (refer to spreadsheet)		57.72			57.72
	Pro Unlimited (refer to spreadsheet)		123.41			123.41
	Pro Unlimited (refer to spreadsheet)		128.25			128.25
	Pro Unlimited (refer to spreadsheet)		171.00			171.00
	Pro Unlimited (refer to spreadsheet)		57.00			57.00
	Pro Unlimited (refer to spreadsheet)		121.13			121.13
	[redacted]					
	Total Pool Activity		**124,518.45**	**-**	**(55,232.39)**	**69,286.06**

III DELIVERY TERMS AND CONDITIONS

ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.22 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	$18.96 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
2011-12

Rate: $0.22 /MMBtu

	Rate	Volume	Total	
Injection Cost	$0.0204	**577,898**	$11,789	
Withdrawal Cost	$0.0204	**407,044**	$8,304	
Delivery Rate	$0.0595	407,044	$24,222	
FTA Demand Charge	$0.4000	407,044	$162,837	
FTA Commodity Charge	$0.0259	407,044	$10,542	
		Total Cost	$217,694	
	Absolute Value of the	Sendout Error	**984,943**	MMBtu
		Rate	$ 0.22	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

TGP FSMA Injection Charge	$0.0204	/ MMBtu
TGP FSMA Withdrawal Charge	$0.0204	/ MMBtu
TGP FSMA Deliverability Charge	$1.81	/ MMBtu per month
	$0.0595	/ MMBtu per day
TGP Z4-6 Demand Charge	$12.17	/ MMBtu per month
	$0.4000	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.0259	/ MMBtu

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

Calculation of Supplier Balancing Charge
2011-12

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	719	722	-3	1,244,158	1,248,436	-4,278	78,427	37,075	41,352
Dec	1,148	1,126	22	2,117,877	2,080,956	36,921	137,615	87,268	50,347
Jan	1,362	1,342	20	2,477,020	2,443,455	33,565	154,398	93,981	60,417
Feb	1,145	1,097	48	2,094,333	2,013,778	80,555	184,606	132,581	52,025
Mar	955	901	54	1,780,835	1,695,042	85,793	174,764	130,279	44,485
Apr	375	391	-16	702,902	720,161	-17,259	88,454	35,597	52,857
May	132	147	-15	442,692	455,680	-12,988	45,892	16,452	29,440
Jun	19	38	-19	307,039	315,681	-8,642	12,281	1,819	10,462
Jul	2	1	1	264,415	264,415	0	0	0	0
Aug	1	2	-1	279,250	279,250	0	0	0	0
Sep	55	75	-20	301,209	308,171	-6,962	14,621	3,829	10,792
Oct	433	446	-13	717,792	733,642	-15,851	93,884	39,017	54,867
Total	**6,346**	**6,288**	**58**	**12,729,522**	**12,558,668**	**170,854**	**984,943**	**577,898**	**407,044**

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

Calculation of Supplier Balancing Charge
2011-12
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)
Apr 1, 10	12	13	-1	22,891	23,969	-1,079	1,079	0	1,079
Apr 2, 10	7	9	-2	17,497	19,655	-2,157	2,157	0	2,157
Apr 3, 10	2	0	2	12,104	9,946	2,157	2,157	2,157	0
Apr 4, 10	6	3	3	16,418	13,182	3,236	3,236	3,236	0
Apr 5, 10	11	3	8	21,812	13,182	8,630	8,630	8,630	0
Apr 6, 10	4	13	-9	14,261	23,969	-9,708	9,708	0	9,708
Apr 7, 10	0	0	0	9,946	9,946	0	0	0	0
Apr 8, 10	8	16	-8	18,576	27,206	-8,630	8,630	0	8,630
Apr 9, 10	16	21	-5	27,206	32,599	-5,394	5,394	0	5,394
Apr 10, 10	17	15	2	28,284	26,127	2,157	2,157	2,157	0
Apr 11, 10	13	11	2	23,969	21,812	2,157	2,157	2,157	0
Apr 12, 10	17	18	-1	28,284	29,363	-1,079	1,079	0	1,079
Apr 13, 10	15	18	-3	26,127	29,363	-3,236	3,236	0	3,236
Apr 14, 10	12	13	-1	22,891	23,969	-1,079	1,079	0	1,079
Apr 15, 10	15	19	-4	26,127	30,442	-4,315	4,315	0	4,315
Apr 16, 10	21	27	-6	32,599	39,071	-6,472	6,472	0	6,472
Apr 17, 10	25	26	-1	36,914	37,993	-1,079	1,079	0	1,079
Apr 18, 10	21	21	0	32,599	32,599	0	0	0	0
Apr 19, 10	17	14	3	28,284	25,048	3,236	3,236	3,236	0
Apr 20, 10	12	11	1	22,891	21,812	1,079	1,079	1,079	0
Apr 21, 10	5	5	0	15,340	15,340	0	0	0	0
Apr 22, 10	11	8	3	21,812	18,576	3,236	3,236	3,236	0
Apr 23, 10	13	12	1	23,969	22,891	1,079	1,079	1,079	0
Apr 24, 10	8	7	1	18,576	17,497	1,079	1,079	1,079	0
Apr 25, 10	13	10	3	23,969	20,733	3,236	3,236	3,236	0
Apr 26, 10	14	11	3	25,048	21,812	3,236	3,236	3,236	0
Apr 27, 10	20	25	-5	31,520	36,914	-5,394	5,394	0	5,394
Apr 28, 10	20	23	-3	31,520	34,756	-3,236	3,236	0	3,236
Apr 29, 10	15	15	0	26,127	26,127	0	0	0	0
Apr 30, 10	5	4	1	15,340	14,261	1,079	1,079	1,079	0
May 1, 10	0	0	0	10,593	10,593	0	0	0	0
May 2, 10	0	0	0	10,593	10,593	0	0	0	0
May 3, 10	0	0	0	10,593	10,593	0	0	0	0
May 4, 10	1	3	-2	11,459	13,191	-1,732	1,732	0	1,732
May 5, 10	0	0	0	10,593	10,593	0	0	0	0
May 6, 10	4	3	1	14,057	13,191	866	866	866	0
May 7, 10	6	8	-2	15,789	17,520	-1,732	1,732	0	1,732
May 8, 10	12	18	-6	20,984	26,179	-5,195	5,195	0	5,195
May 9, 10	16	20	-4	24,448	27,911	-3,464	3,464	0	3,464
May 10, 10	15	19	-4	23,582	27,045	-3,464	3,464	0	3,464
May 11, 10	10	14	-4	19,252	22,716	-3,464	3,464	0	3,464
May 12, 10	16	17	-1	24,448	25,313	-866	866	0	866
May 13, 10	8	7	1	17,520	16,655	866	866	866	0
May 14, 10	10	5	5	19,252	14,923	4,329	4,329	4,329	0
May 15, 10	6	4	2	15,789	14,057	1,732	1,732	1,732	0
May 16, 10	3	5	-2	13,191	14,923	-1,732	1,732	0	1,732
May 17, 10	0	3	-3	10,593	13,191	-2,598	2,598	0	2,598
May 18, 10	5	9	-4	14,923	18,386	-3,464	3,464	0	3,464
May 19, 10	10	10	0	19,252	19,252	0	0	0	0
May 20, 10	0	0	0	10,593	10,593	0	0	0	0
May 21, 10	0	2	-2	10,593	12,325	-1,732	1,732	0	1,732
May 22, 10	1	0	1	11,459	10,593	866	866	866	0
May 23, 10	4	0	4	14,057	10,593	3,464	3,464	3,464	0
May 24, 10	0	0	0	10,593	10,593	0	0	0	0
May 25, 10	0	0	0	10,593	10,593	0	0	0	0
May 26, 10	0	0	0	10,593	10,593	0	0	0	0
May 27, 10	1	0	1	11,459	10,593	866	866	866	0
May 28, 10	4	0	4	14,057	10,593	3,464	3,464	3,464	0
May 29, 10	0	0	0	10,593	10,593	0	0	0	0
May 30, 10	0	0	0	10,593	10,593	0	0	0	0
May 31, 10	0	0	0	10,593	10,593	0	0	0	0
Jun 1, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 2, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 3, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 4, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 5, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 6, 10	2	4	-2	10,856	11,766	-910	910	0	910
Jun 7, 10	0	4	-4	9,947	11,766	-1,819	1,819	0	1,819
Jun 8, 10	3	5	-2	11,311	12,221	-910	910	0	910
Jun 9, 10	1	6	-5	10,401	12,676	-2,274	2,274	0	2,274
Jun 10, 10	9	9	0	14,040	14,040	0	0	0	0
Jun 11, 10	0	2	-2	9,947	10,856	-910	910	0	910
Jun 12, 10	0	4	-4	9,947	11,766	-1,819	1,819	0	1,819
Jun 13, 10	0	4	-4	9,947	11,766	-1,819	1,819	0	1,819
Jun 14, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 15, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 16, 10	4	0	4	11,766	9,947	1,819	1,819	1,819	0
Jun 17, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 18, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 19, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 20, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 21, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 22, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 23, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 24, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 25, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 26, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 27, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 28, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 29, 10	0	0	0	9,947	9,947	0	0	0	0
Jun 30, 10	0	0	0	9,947	9,947	0	0	0	0
Jul 1, 10	2	1	1	8,530	8,530	0	0	0	0
Jul 2, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 3, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 4, 10	0	0	0	8,530	8,530	0	0	0	0

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

Calculation of Supplier Balancing Charge
2011-12
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)
Jul 5, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 6, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 7, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 8, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 9, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 10, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 11, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 12, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 13, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 14, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 15, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 16, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 17, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 18, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 19, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 20, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 21, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 22, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 23, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 24, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 25, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 26, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 27, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 28, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 29, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 30, 10	0	0	0	8,530	8,530	0	0	0	0
Jul 31, 10	0	0	0	8,530	8,530	0	0	0	0
Aug 1, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 2, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 3, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 4, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 5, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 6, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 7, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 8, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 9, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 10, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 11, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 12, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 13, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 14, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 15, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 16, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 17, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 18, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 19, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 20, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 21, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 22, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 23, 10	0	1	-1	9,008	9,008	0	0	0	0
Aug 24, 10	1	1	0	9,008	9,008	0	0	0	0
Aug 25, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 26, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 27, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 28, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 29, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 30, 10	0	0	0	9,008	9,008	0	0	0	0
Aug 31, 10	0	0	0	9,008	9,008	0	0	0	0
Sep 1, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 2, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 3, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 4, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 5, 10	1	4	-3	9,750	10,795	-1,044	1,044	0	1,044
Sep 6, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 7, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 8, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 9, 10	2	2	0	10,098	10,098	0	0	0	0
Sep 10, 10	5	2	3	11,143	10,098	1,044	1,044	1,044	0
Sep 11, 10	2	2	0	10,098	10,098	0	0	0	0
Sep 12, 10	2	7	-5	10,098	11,839	-1,741	1,741	0	1,741
Sep 13, 10	0	6	-6	9,402	11,491	-2,089	2,089	0	2,089
Sep 14, 10	5	5	0	11,143	11,143	0	0	0	0
Sep 15, 10	8	10	-2	12,187	12,883	-696	696	0	696
Sep 16, 10	2	1	1	10,098	9,750	348	348	348	0
Sep 17, 10	3	5	-2	10,446	11,143	-696	696	0	696
Sep 18, 10	2	7	-5	10,098	11,839	-1,741	1,741	0	1,741
Sep 19, 10	3	1	2	10,446	9,750	696	696	696	0
Sep 20, 10	8	8	0	12,187	12,187	0	0	0	0
Sep 21, 10	4	0	4	10,795	9,402	1,392	1,392	1,392	0
Sep 22, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 23, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 24, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 25, 10	1	0	1	9,750	9,402	348	348	348	0
Sep 26, 10	6	8	-2	11,491	12,187	-696	696	0	696
Sep 27, 10	1	7	-6	9,750	11,839	-2,089	2,089	0	2,089
Sep 28, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 29, 10	0	0	0	9,402	9,402	0	0	0	0
Sep 30, 10	0	0	0	9,402	9,402	0	0	0	0
Oct 1, 10	6	7	-1	13,440	14,659	-1,219	1,219	0	1,219
Oct 2, 10	13	14	-1	21,975	23,194	-1,219	1,219	0	1,219
Oct 3, 10	14	12	2	23,194	20,755	2,439	2,439	2,439	0
Oct 4, 10	14	8	6	23,194	15,878	7,316	7,316	7,316	0
Oct 5, 10	8	8	0	15,878	15,878	0	0	0	0
Oct 6, 10	14	13	1	23,194	21,975	1,219	1,219	1,219	0
Oct 7, 10	10	9	1	18,317	17,098	1,219	1,219	1,219	0
Oct 8, 10	6	4	2	13,440	11,001	2,439	2,439	2,439	0

EnergyNorth Natural Gas Inc.
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Calculation of Supplier Balancing Charge
2011-12
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)
Oct 9, 10	17	15	2	26,852	24,413	2,439	2,439	2,439	0
Oct 10, 10	12	12	0	20,755	20,755	0	0	0	0
Oct 11, 10	11	12	-1	19,536	20,755	-1,219	1,219	0	1,219
Oct 12, 10	17	16	1	26,852	25,632	1,219	1,219	1,219	0
Oct 13, 10	14	16	-2	23,194	25,632	-2,439	2,439	0	2,439
Oct 14, 10	9	13	-4	17,098	21,975	-4,877	4,877	0	4,877
Oct 15, 10	19	21	-2	29,290	31,729	-2,439	2,439	0	2,439
Oct 16, 10	18	17	1	28,071	26,852	1,219	1,219	1,219	0
Oct 17, 10	16	14	2	25,632	23,194	2,439	2,439	2,439	0
Oct 18, 10	20	21	-1	30,510	31,729	-1,219	1,219	0	1,219
Oct 19, 10	16	22	-6	25,632	32,948	-7,316	7,316	0	7,316
Oct 20, 10	13	19	-6	21,975	29,290	-7,316	7,316	0	7,316
Oct 21, 10	20	21	-1	30,510	31,729	-1,219	1,219	0	1,219
Oct 22, 10	26	25	1	37,825	36,606	1,219	1,219	1,219	0
Oct 23, 10	19	21	-2	29,290	31,729	-2,439	2,439	0	2,439
Oct 24, 10	12	21	-9	20,755	31,729	-10,973	10,973	0	10,973
Oct 25, 10	5	12	-7	12,220	20,755	-8,535	8,535	0	8,535
Oct 26, 10	2	0	2	8,563	6,124	2,439	2,439	2,439	0
Oct 27, 10	6	3	3	13,440	9,782	3,658	3,658	3,658	0
Oct 28, 10	10	9	1	18,317	17,098	1,219	1,219	1,219	0
Oct 29, 10	21	20	1	31,729	30,510	1,219	1,219	1,219	0
Oct 30, 10	21	15	6	31,729	24,413	7,316	7,316	7,316	0
Oct 31, 10	24	26	-2	35,387	37,825	-2,439	2,439	0	2,439
Nov 1, 10	26	23	3	44,371	40,094	4,278	4,278	4,278	0
Nov 2, 10	28	28	0	47,223	47,223	0	0	0	0
Nov 3, 10	25	28	-3	42,945	47,223	-4,278	4,278	0	4,278
Nov 4, 10	21	20	1	37,242	35,816	1,426	1,426	1,426	0
Nov 5, 10	20	20	0	35,816	35,816	0	0	0	0
Nov 6, 10	25	24	1	42,945	41,519	1,426	1,426	1,426	0
Nov 7, 10	26	26	0	44,371	44,371	0	0	0	0
Nov 8, 10	24	21	3	41,519	37,242	4,278	4,278	4,278	0
Nov 9, 10	19	17	2	34,390	31,538	2,852	2,852	2,852	0
Nov 10, 10	25	20	5	42,945	35,816	7,130	7,130	7,130	0
Nov 11, 10	24	23	1	41,519	40,094	1,426	1,426	1,426	0
Nov 12, 10	21	21	0	37,242	37,242	0	0	0	0
Nov 13, 10	19	20	-1	34,390	35,816	-1,426	1,426	0	1,426
Nov 14, 10	20	18	2	35,816	32,964	2,852	2,852	2,852	0
Nov 15, 10	18	17	1	32,964	31,538	1,426	1,426	1,426	0
Nov 16, 10	14	15	-1	27,260	28,686	-1,426	1,426	0	1,426
Nov 17, 10	17	15	2	31,538	28,686	2,852	2,852	2,852	0
Nov 18, 10	24	25	-1	41,519	42,945	-1,426	1,426	0	1,426
Nov 19, 10	27	31	-4	45,797	51,501	-5,704	5,704	0	5,704
Nov 20, 10	27	26	1	45,797	44,371	1,426	1,426	1,426	0
Nov 21, 10	28	32	-4	47,223	52,927	-5,704	5,704	0	5,704
Nov 22, 10	18	23	-5	32,964	40,094	-7,130	7,130	0	7,130
Nov 23, 10	18	18	0	32,964	32,964	0	0	0	0
Nov 24, 10	33	31	2	54,353	51,501	2,852	2,852	2,852	0
Nov 25, 10	28	31	-3	47,223	51,501	-4,278	4,278	0	4,278
Nov 26, 10	30	31	-1	50,075	51,501	-1,426	1,426	0	1,426
Nov 27, 10	34	34	0	55,779	55,779	0	0	0	0
Nov 28, 10	31	32	-1	51,501	52,927	-1,426	1,426	0	1,426
Nov 29, 10	27	32	-5	45,797	52,927	-7,130	7,130	0	7,130
Nov 30, 10	22	20	2	38,668	35,816	2,852	2,852	2,852	0
Dec 1, 10	20	20	0	39,734	39,734	0	0	0	0
Dec 2, 10	30	31	-1	56,517	58,195	-1,678	1,678	0	1,678
Dec 3, 10	30	29	1	56,517	54,839	1,678	1,678	1,678	0
Dec 4, 10	32	33	-1	59,873	61,552	-1,678	1,678	0	1,678
Dec 5, 10	34	37	-3	63,230	68,264	-5,035	5,035	0	5,035
Dec 6, 10	34	37	-3	63,230	68,264	-5,035	5,035	0	5,035
Dec 7, 10	37	37	0	68,264	68,264	0	0	0	0
Dec 8, 10	42	42	0	76,656	76,656	0	0	0	0
Dec 9, 10	46	48	-2	83,369	86,725	-3,356	3,356	0	3,356
Dec 10, 10	38	41	-3	69,943	74,977	-5,035	5,035	0	5,035
Dec 11, 10	31	33	-2	58,195	61,552	-3,356	3,356	0	3,356
Dec 12, 10	22	15	7	43,091	31,343	11,748	11,748	11,748	0
Dec 13, 10	35	27	8	64,908	51,482	13,426	13,426	13,426	0
Dec 14, 10	44	46	-2	80,012	83,369	-3,356	3,356	0	3,356
Dec 15, 10	47	47	0	85,047	85,047	0	0	0	0
Dec 16, 10	42	44	-2	76,656	80,012	-3,356	3,356	0	3,356
Dec 17, 10	40	43	-3	73,299	78,334	-5,035	5,035	0	5,035
Dec 18, 10	37	38	-1	68,264	69,943	-1,678	1,678	0	1,678
Dec 19, 10	35	37	-2	64,908	68,264	-3,356	3,356	0	3,356
Dec 20, 10	33	38	-5	61,552	69,943	-8,391	8,391	0	8,391
Dec 21, 10	36	32	4	66,586	59,873	6,713	6,713	6,713	0
Dec 22, 10	37	34	3	68,264	63,230	5,035	5,035	5,035	0
Dec 23, 10	42	35	7	76,656	64,908	11,748	11,748	11,748	0
Dec 24, 10	41	40	1	74,977	73,299	1,678	1,678	1,678	0
Dec 25, 10	42	41	1	76,656	74,977	1,678	1,678	1,678	0
Dec 26, 10	42	39	3	76,656	71,621	5,035	5,035	5,035	0
Dec 27, 10	48	47	1	86,725	85,047	1,678	1,678	1,678	0
Dec 28, 10	44	36	8	80,012	66,586	13,426	13,426	13,426	0
Dec 29, 10	41	35	6	74,977	64,908	10,069	10,069	10,069	0
Dec 30, 10	37	36	1	68,264	66,586	1,678	1,678	1,678	0
Dec 31, 10	29	28	1	54,839	53,160	1,678	1,678	1,678	0
Jan 1, 11	27	21	6	51,482	41,413	10,069	10,069	10,069	0
Jan 2, 11	33	28	5	61,552	53,160	8,391	8,391	8,391	0
Jan 3, 11	40	39	1	73,299	71,621	1,678	1,678	1,678	0
Jan 4, 11	36	37	-1	66,586	68,264	-1,678	1,678	0	1,678
Jan 5, 11	41	39	2	74,977	71,621	3,356	3,356	3,356	0
Jan 6, 11	40	45	-5	73,299	81,690	-8,391	8,391	0	8,391
Jan 7, 11	38	40	-2	69,943	73,299	-3,356	3,356	0	3,356
Jan 8, 11	38	37	1	69,943	68,264	1,678	1,678	1,678	0
Jan 9, 11	42	39	3	76,656	71,621	5,035	5,035	5,035	0
Jan 10, 11	43	42	1	78,334	76,656	1,678	1,678	1,678	0
Jan 11, 11	38	40	-2	69,943	73,299	-3,356	3,356	0	3,356
Jan 12, 11	40	39	1	73,299	71,621	1,678	1,678	1,678	0

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

Calculation of Supplier Balancing Charge
2011-12
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)
Jan 13, 11	46	46	0	83,369	83,369	0	0	0	0
Jan 14, 11	51	52	-1	91,760	93,438	-1,678	1,678	0	1,678
Jan 15, 11	42	41	1	76,656	74,977	1,678	1,678	1,678	0
Jan 16, 11	47	46	1	85,047	83,369	1,678	1,678	1,678	0
Jan 17, 11	47	55	-8	85,047	98,473	-13,426	13,426	0	13,426
Jan 18, 11	33	36	-3	61,552	66,586	-5,035	5,035	0	5,035
Jan 19, 11	38	36	2	69,943	66,586	3,356	3,356	3,356	0
Jan 20, 11	47	42	5	85,047	76,656	8,391	8,391	8,391	0
Jan 21, 11	49	46	3	88,403	83,369	5,035	5,035	5,035	0
Jan 22, 11	55	54	1	98,473	96,795	1,678	1,678	1,678	0
Jan 23, 11	67	61	6	118,612	108,542	10,069	10,069	10,069	0
Jan 24, 11	67	61	6	118,612	108,542	10,069	10,069	10,069	0
Jan 25, 11	45	56	-11	81,690	100,151	-18,461	18,461	0	18,461
Jan 26, 11	37	40	-3	68,264	73,299	-5,035	5,035	0	5,035
Jan 27, 11	45	44	1	81,690	80,012	1,678	1,678	1,678	0
Jan 28, 11	44	40	4	80,012	73,299	6,713	6,713	6,713	0
Jan 29, 11	44	42	2	80,012	76,656	3,356	3,356	3,356	0
Jan 30, 11	48	46	2	86,725	83,369	3,356	3,356	3,356	0
Jan 31, 11	54	52	2	96,795	93,438	3,356	3,356	3,356	0
Feb 1, 11	45	48	-3	81,690	86,725	-5,035	5,035	0	5,035
Feb 2, 11	49	46	3	88,403	83,369	5,035	5,035	5,035	0
Feb 3, 11	52	53	-1	93,438	95,116	-1,678	1,678	0	1,678
Feb 4, 11	45	44	1	81,690	80,012	1,678	1,678	1,678	0
Feb 5, 11	37	33	4	68,264	61,552	6,713	6,713	6,713	0
Feb 6, 11	41	33	8	74,977	61,552	13,426	13,426	13,426	0
Feb 7, 11	34	30	4	63,230	56,517	6,713	6,713	6,713	0
Feb 8, 11	48	45	3	86,725	81,690	5,035	5,035	5,035	0
Feb 9, 11	48	42	6	86,725	76,656	10,069	10,069	10,069	0
Feb 10, 11	52	49	3	93,438	88,403	5,035	5,035	5,035	0
Feb 11, 11	47	49	-2	85,047	88,403	-3,356	3,356	0	3,356
Feb 12, 11	42	40	2	76,656	73,299	3,356	3,356	3,356	0
Feb 13, 11	34	34	0	63,230	63,230	0	0	0	0
Feb 14, 11	43	31	12	78,334	58,195	20,139	20,139	20,139	0
Feb 15, 11	50	48	2	90,082	86,725	3,356	3,356	3,356	0
Feb 16, 11	32	33	-1	59,873	61,552	-1,678	1,678	0	1,678
Feb 17, 11	26	24	2	49,804	46,447	3,356	3,356	3,356	0
Feb 18, 11	24	19	5	46,447	38,056	8,391	8,391	8,391	0
Feb 19, 11	41	46	-5	74,977	83,369	-8,391	8,391	0	8,391
Feb 20, 11	41	41	0	74,977	74,977	0	0	0	0
Feb 21, 11	41	50	-9	74,977	90,082	-15,104	15,104	0	15,104
Feb 22, 11	48	42	6	86,725	76,656	10,069	10,069	10,069	0
Feb 23, 11	46	40	6	83,369	73,299	10,069	10,069	10,069	0
Feb 24, 11	33	29	4	61,552	54,839	6,713	6,713	6,713	0
Feb 25, 11	35	36	-1	64,908	66,586	-1,678	1,678	0	1,678
Feb 26, 11	45	37	8	81,690	68,264	13,426	13,426	13,426	0
Feb 27, 11	38	42	-4	69,943	76,656	-6,713	6,713	0	6,713
Feb 28, 11	28	33	-5	53,160	61,552	-8,391	8,391	0	8,391
Mar 1, 11	39	36	3	70,464	65,698	4,766	4,766	4,766	0
Mar 2, 11	43	42	1	76,819	75,230	1,589	1,589	1,589	0
Mar 3, 11	52	49	3	91,118	86,352	4,766	4,766	4,766	0
Mar 4, 11	36	34	2	65,698	62,520	3,178	3,178	3,178	0
Mar 5, 11	24	17	7	46,632	35,511	11,121	11,121	11,121	0
Mar 6, 11	24	21	3	46,632	41,866	4,766	4,766	4,766	0
Mar 7, 11	36	39	-3	65,698	70,464	-4,766	4,766	0	4,766
Mar 8, 11	36	34	2	65,698	62,520	3,178	3,178	3,178	0
Mar 9, 11	32	32	0	59,343	59,343	0	0	0	0
Mar 10, 11	24	26	-2	46,632	49,810	-3,178	3,178	0	3,178
Mar 11, 11	22	23	-1	43,455	45,044	-1,589	1,589	0	1,589
Mar 12, 11	28	23	5	52,987	45,044	7,944	7,944	7,944	0
Mar 13, 11	36	26	10	65,698	49,810	15,888	15,888	15,888	0
Mar 14, 11	30	34	-4	56,165	62,520	-6,355	6,355	0	6,355
Mar 15, 11	26	28	-2	49,810	52,987	-3,178	3,178	0	3,178
Mar 16, 11	26	31	-5	49,810	57,754	-7,944	7,944	0	7,944
Mar 17, 11	18	12	6	37,100	27,567	9,533	9,533	9,533	0
Mar 18, 11	19	14	5	38,689	30,745	7,944	7,944	7,944	0
Mar 19, 11	30	29	1	56,165	54,576	1,589	1,589	1,589	0
Mar 20, 11	29	14	15	54,576	30,745	23,831	23,831	23,831	0
Mar 21, 11	24	32	-8	46,632	59,343	-12,710	12,710	0	12,710
Mar 22, 11	30	30	0	56,165	56,165	0	0	0	0
Mar 23, 11	29	32	-3	54,576	59,343	-4,766	4,766	0	4,766
Mar 24, 11	33	32	1	60,931	59,343	1,589	1,589	1,589	0
Mar 25, 11	36	34	2	65,698	62,520	3,178	3,178	3,178	0
Mar 26, 11	37	35	2	67,286	64,109	3,178	3,178	3,178	0
Mar 27, 11	37	33	4	67,286	60,931	6,355	6,355	6,355	0
Mar 28, 11	33	30	3	60,931	56,165	4,766	4,766	4,766	0
Mar 29, 11	30	28	2	56,165	52,987	3,178	3,178	3,178	0
Mar 30, 11	28	23	5	52,987	45,044	7,944	7,944	7,944	0
Mar 31, 11	28	28	0	52,987	52,987	0	0	0	0
Apr 1, 11	0	0	0	0	0	0	0	0	0
Apr	375	391	-16	702,902	720,161	-17,259	88,454	35,597	52,857
May	132	147	-15	442,692	455,680	-12,988	45,892	16,452	29,440
Jun	19	38	-19	307,039	315,681	-8,642	12,281	1,819	10,462
Jul	2	1	1	264,415	264,415	0	0	0	0
Aug	1	2	-1	279,250	279,250	0	0	0	0
Sep	55	75	-20	301,209	308,171	-6,962	14,621	3,829	10,792
Oct	433	446	-13	717,792	733,642	-15,851	93,884	39,017	54,867
Nov	719	722	-3	1,244,158	1,248,436	-4,278	78,427	37,075	41,352
Dec	1,148	1,126	22	2,117,877	2,080,956	36,921	137,615	87,268	50,347
Jan	1,362	1,342	20	2,477,020	2,443,455	33,565	154,398	93,981	60,417
Feb	1,145	1,097	48	2,094,333	2,013,778	80,555	184,606	132,581	52,025
Mar	955	901	54	1,780,835	1,695,042	85,793	174,764	130,279	44,485
Total	6,346	6,288	58	12,729,522	12,558,668	170,854	984,943	577,898	407,044
Datacheck	0	0	0	0	0	0	0	0	0

Schedule 21
2011 - 2012 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third Revised Page 155
Attachment B - Peaking Demand Charge

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

					Source:
1	Peak Day		137,200	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: 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		
		TGP FT-A (Z6-Z6) 72694	4,000		
10			53,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3 of 3: 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		55,367	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,067,040		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$250,367		Attachment B Page 3 Line 1
27	Total		$6,297,835		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$113.75		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$18.96**	**/Dekatherm**	Line 29 divided by 6 month

Schedule 21
2011 - 2012 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third Revised Page 155
Attachment B - Peaking Demand Charge
Page 2 of 3

ENERGY NORTH NATURAL GAS

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	52.00%	38.00%
Storage	16.00%	21.00%
Peaking	32.00%	41.00%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2009:

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE *	Supply at Waddington		4,000		$14.4264		10/31/2017	X
	Iroquois	RTS to Wright	470-01	4,047		$6.5971		11/01/2017	
	TGP	NET-NE	33371	4,000		$10.7923		11/30/2011	
	BP Canada Energy Co.**	Supply at Niagara		3,199		$0.0000		03/31/2012	X
	TGP	FT-A (Z5-Z6)	2302	3,122		$10.7923		10/31/2015	
	TGP	FT-A (Z0-Z6)	8587	7,035		$33.0885		10/31/2015	
	TGP	FT-A (Z1-Z6)	8587	14,561		$29.4677		10/31/2015	
	TGP	FT-A (Z6-Z6)	42076	20,000		$7.4442		10/31/2015	
	TGP	FT-A (Z6-Z6)	72694	4,000		$12.1700		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	$1.8100	$0.0250	10/31/2015	
	TGP	FT-A (Z4-Z6)	632	15,265		$12.1681		10/31/2015	
	TGP	FT-A (Z4-Z6)	8587	3,811		$12.1681		10/31/2015	
	National Fuel	FSS-1 (Storage)	O02357***	6,098	670,800	$2.1556	$0.0432	03/31/2011	
	National Fuel	FST (Transport)	N02358	6,098		$3.3612		03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	6,150		$12.1681		10/31/2011	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	$4.4683	$0.0000	04/01/2011	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$10.7923		10/31/2011	
	Dominion	GSS (Storage)	300076***	934	102,700	$1.8892	$0.0145	03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	932		$12.1681		10/31/2011	
Peaking									
	Energy North	LNG/Propane****		29,367	-	$18.9600	$0.0000		X
	TGP	FT-A (Z6-Z6)	72694	26,000	-	$12.1700	$0.0000	10/31/2029	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 $40.2456/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	[redacted]				
2						
3						
4	Concord Lateral	[redacted]				
5	DOMAC * FLS 160					
6						
7	Subtotal					**$4,067,040** *
8						
9	**Total**					**$4,317,407**
10						

* Contract currently being negotiated for an effective date of November 1, 2011.

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ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	38.0%	21.0%	41.0%	100.0%
G-51	Low Annual /Low Winter Use	52.0%	16.0%	32.0%	100.0%
G-42	Medium Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-52	High Annual / Low Winter Use	52.0%	16.0%	32.0%	100.0%
G-43	High Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-53	High Annual / Load Factor < 90%	52.0%	16.0%	32.0%	100.0%
G-54	High Annual / Load Factor < 90%	52.0%	16.0%	32.0%	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	38.0%	21.0%	41.0%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	52.0%	16.0%	32.0%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	52.0%	16.0%	32.0%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	52.0%	16.0%	32.0%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	52.0%	16.0%	32.0%	100.0%

HLF	High Load Factor	52%	16%	32%	100%
LLF	Low Load Factor	38%	21%	41%	100%
	Total	39%	21%	40%	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		Base load	72 Heat load	Total
HLF	R-1 RNSH	141	531	672
LLF	R-3 RSH	3,851	61,376	65,227
LLF	G-41 SL	844	23,259	24,103
HLF	G-51 SH	618	1,943	2,561
LLF	G-42 ML	1,773	32,262	34,035
HLF	G-52 MH	1,252	2,929	4,181
LLF	G-43 LL	388	4,100	4,488
HLF	G-53 LLL90	288	1,434	1,722
HLF	G-54 LLG90	210	-	210
	TOTAL	9,365	127,835	137,200

HLF	2,510	6,836	9,346
LLF	6,856	120,999	127,854
Total	9,365	127,835	137,200

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	141	184	326	117	230	672
R-3 RSH	3,851	21,295	25,146	13,499	26,583	65,227
G-41 SL	844	8,070	8,914	5,116	10,074	24,103
G-51 SH	618	674	1,292	427	841	2,561
G-42 ML	1,773	11,193	12,967	7,095	13,973	34,035
G-52 MH	1,252	1,016	2,268	644	1,268	4,181
G-43 LL	388	1,423	1,811	902	1,776	4,488
G-53 LLL90	288	497	785	315	621	1,722
G-54 LLG90	210	-	210	-	-	210
TOTAL	9,365	44,353	53,718	28,115	55,367	137,200

HLF	2,510	2,372	4,881	1,504	2,961	9,346
LLF	6,856	41,981	48,837	26,611	52,406	127,854
Total	9,365	44,353	53,718	28,115	55,367	137,200

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	48.4%	17.4%	34.2%	100.0%
R-3 RSH	38.6%	20.7%	40.8%	100.0%
G-41 SL	37.0%	21.2%	41.8%	100.0%
G-51 SH	50.5%	16.7%	32.9%	100.0%
G-42 ML	38.1%	20.8%	41.1%	100.0%
G-52 MH	54.3%	15.4%	30.3%	100.0%
G-43 LL	40.3%	20.1%	39.6%	100.0%
G-53 LLL90	45.6%	18.3%	36.1%	100.0%
G-54 LLG90	100.0%	0.0%	0.0%	100.0%
TOTAL	39.2%	20.5%	40.4%	100.0%

High Load Factor	52%	16%	32%	100%
Low Load Factor	38%	21%	41%	100%
Total	39%	20%	40%	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 72

	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	141	6.973	502	643	22%	0.415%	141	531	672
R-3 RSH	3,851	805.784	58,016	61,867	6%	48.012%	3,851	61,376	65,227
G-41 SL	844	305.363	21,986	22,830	4%	18.195%	844	23,259	24,103
G-51 SH	618	25.507	1,836	2,454	25%	1.520%	618	1,943	2,561
G-42 ML	1,773	423.555	30,496	32,269	5%	25.237%	1,773	32,262	34,035
G-52 MH	1,252	38.448	2,768	4,020	31%	2.291%	1,252	2,929	4,181
G-43 LL	388	53.833	3,876	4,264	9%	3.208%	388	4,100	4,488
G-53 LLL90	288	18.824	1,355	1,643	18%	1.122%	288	1,434	1,722
G-54 LLG90	210	-	-	210	100%	0.000%	210	-	210
TOTAL	9,365	1,655.325	120,837	130,202		100.000%	9,365	127,835	137,200

HLF	2,510	90	6,462	8,972
LLF	6,856	1,566	114,375	121,230
Total	9,365	1,655	120,837	130,202

Design Day from 2011-2012 Resource Plan		**137,200**
Design Day from Billing Calculation		130,202
Variance		6,998

00000198

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

<u>CALCULATION OF NORMAL SALES VOLUMES</u>

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-10	Sep-10	Oct-10	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	7	10	12	12	11	9	7	6	5	4	4	5	92	4.379	0.141
LLF	R-3 RSH	370	690	997	1,090	943	707	354	186	134	105	113	157	5,845	119.372	3.851
LLF	G-41 SL	105	218	374	396	348	240	106	47	30	22	25	37	1,950	26.155	0.844
HLF	G-51 SH	24	36	47	48	45	39	26	22	21	18	19	21	365	19.156	0.618
LLF	G-42 ML	184	329	518	566	488	372	188	98	62	48	49	77	2,980	54.969	1.773
HLF	G-52 MH	52	66	80	82	81	69	52	44	42	36	38	40	682	38.812	1.252
LLF	G-43 LL	13	32	55	77	70	69	46	26	17	7	11	(0)	422	12.028	0.388
HLF	G-53 LLL90	1	1	11	31	21	34	15	17	16	2	8	3	160	8.929	0.288
HLF	G-54 LLL110	10	37	21	(1)	(12)	29	(4)	13	13	0	20	(2)	124	6.523	0.210
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0.000	0.000
	TOTAL	767	1,420	2,116	2,302	1,996	1,568	790	458	340	241	286	337	12,621	290.321	9.365
	HLF	95	150	171	172	146	180	96	102	97	59	89	67	1,424	77.798	2.510
	LLF	672	1,270	1,944	2,129	1,850	1,388	695	356	243	182	197	270	11,197	212.523	6.856

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

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-10	Sep-10	Oct-10	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	4	4	4	4	4	4	4	4	5	4	4	4	52
LLF	R-3 RSH	116	119	119	108	119	116	119	116	134	105	113	119	1,406
LLF	G-41 SL	25	26	26	24	26	25	26	25	30	22	25	26	308
HLF	G-51 SH	19	19	19	17	19	19	19	19	21	18	19	19	226
LLF	G-42 ML	53	55	55	50	55	53	55	53	62	48	49	55	647
HLF	G-52 MH	38	39	39	35	39	38	39	38	42	36	38	39	457
LLF	G-43 LL	12	12	12	11	12	12	12	12	17	7	11	(0)	142
HLF	G-53 LLL90	1	1	9	8	9	9	9	9	16	2	8	3	105
HLF	G-54 LLL110	6	7	7	(1)	(12)	6	(4)	6	13	0	6	(2)	77
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	304	313	321	283	303	311	311	311	371	272	302	294	3,418
	HLF	68	70	78	63	59	75	68	75	97	59	75	63	916
	LLF	206	213	213	192	213	206	213	206	243	182	197	200	2,502

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

Heating Volumes (= Actual Volumes - Baseload)

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	2	6	8	9	6	5	3	1	0	0	0	0	41
LLF	R-3 RSH	254	571	877	983	824	591	235	70	0	0	0	38	4,440
LLF	G-41 SL	80	192	348	372	322	214	80	22	0	0	0	11	1,642
HLF	G-51 SH	6	17	28	31	26	20	7	3	0	0	0	2	140
LLF	G-42 ML	131	274	463	517	434	319	133	44	0	0	0	22	2,333
HLF	G-52 MH	15	27	41	47	42	31	13	7	0	0	0	1	225
LLF	G-43 LL	1	20	43	66	58	57	34	14	0	0	0	0	280
HLF	G-53 LLL90	0	0	2	23	12	26	6	9	0	0	0	0	55
HLF	G-54 LLL110	4	30	14	0	0	23	0	7	0	0	14	0	47
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	463	1,106	1,794	2,019	1,693	1,257	479	147	(31)	(31)	(16)	43	9,202

HLF	27	80	94	109	87	105	28	27	0	0	14	4	508
LLF	466	1,057	1,732	1,937	1,638	1,182	482	151	0	0	0	70	8,695

Actual BDD	**584.0**	**924.0**	**1234.0**	**1219.5**	**1006.0**	**710.0**	**363.5**	**149.5**	**38.5**	**1.5**	**38.5**	**260.5**	6529.5

Heat Factors

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	0.0042	0.0060	0.0064	0.0070	0.0064	0.0073	0.0077	0.0092	0.0000	0.0000	0.0009	0.0016	
LLF	R-3 RSH	0.4350	0.6178	0.7110	0.8058	0.8188	0.8331	0.6457	0.4703	0.0000	0.0000	0.0000	0.1442	
LLF	G-41 SL	0.1370	0.2077	0.2822	0.3054	0.3204	0.3021	0.2204	0.1461	0.0000	0.0000	0.0000	0.0411	
HLF	G-51 SH	0.0100	0.0183	0.0227	0.0255	0.0260	0.0281	0.0183	0.0211	0.0000	0.0000	0.0002	0.0084	
LLF	G-42 ML	0.2248	0.2967	0.3752	0.4236	0.4309	0.4492	0.3672	0.2968	0.0000	0.0000	0.0000	0.0846	
HLF	G-52 MH	0.0253	0.0297	0.0336	0.0384	0.0420	0.0437	0.0358	0.0437	0.0000	0.0000	0.0092	0.0038	
LLF	G-43 LL	0.0018	0.0218	0.0348	0.0538	0.0578	0.0809	0.0930	0.0942	0.0000	0.0000	0.0000	0.0000	
HLF	G-53 LLL90	0.0000	0.0000	0.0017	0.0188	0.0117	0.0360	0.0157	0.0590	0.0000	0.0000	0.0000	0.0000	
HLF	G-54 LLL110	0.0067	0.0328	0.0114	0.0000	0.0000	0.0324	0.0000	0.0462	0.0000	0.0000	0.3538	0.0000	
HLF	G-63 LLG110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
	TOTAL	0.7935	1.1972	1.4540	1.6553	1.6830	1.7705	1.3185	0.9859	-0.8052	-20.6667	-0.4151	0.1648	

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

Actual BillingDD	**584.0**	**924.0**	**1234.0**	**1219.5**	**1006.0**	**710.0**	**363.5**	**149.5**	**38.5**	**1.5**	**38.5**	**260.5**	**6529.5**
Norm Billing DD	**560.9**	**876.8**	**1140.2**	**1136.4**	**969.3**	**704.4**	**376.4**	**145.2**	**27.9**	**8.7**	**63.3**	**266.6**	**6276.0**

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

		Nov-10	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-10**	**Sep-10**	**Oct-10**	**Total**
HLF	**R-1 RNSH**	7	10	12	12	11	9	7	6	5	4	4	5	91
LLF	**R-3 RSH**	359	661	930	1,024	913	702	362	184	134	105	113	158	5,645
LLF	**G-41 SL**	102	208	348	371	337	238	109	47	30	22	25	37	1,874
HLF	**G-51 SH**	24	35	45	46	44	38	26	22	21	18	19	21	359
LLF	**G-42 ML**	179	315	483	531	473	370	193	96	62	48	49	78	2,876
HLF	**G-52 MH**	52	65	77	79	79	68	52	44	42	36	38	40	672
LLF	**G-43 LL**	13	31	52	72	68	69	47	25	17	7	11	(0)	411
HLF	**G-53 LLL90**	1	1	11	29	20	34	15	17	16	2	8	3	158
HLF	**G-54 LLL110**	10	35	20	(1)	(12)	29	(4)	13	13	0	29	(2)	130
HLF	**G-63 LLG110**	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	749	1,363	1,979	2,164	1,934	1,558	807	454	348	92	276	338	12,063

HLF	94	146	164	165	143	179	97	101	97	59	98	67	1,409
LLF	654	1,216	1,812	1,997	1,790	1,379	712	352	243	182	197	272	10,806

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 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	15%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$ 1,555.31	$ 1,373.85	$ 181.46	13.21%	$1.2836	$1.0958	$ 2,467.49	$2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10	11%	$0.0200	8,405,413	$ 168,108	$0.9863	$0.9416	$1,250.80	$1,209.12	$ 41.69	3.45%	$0.9865	$0.9408	$1,984.29	$1,919.03	$ 65.26	3.40%
12	Nov 10 - Apr 11	13%	$0.0200	10,379,804	$ 207,596	$0.8420	$0.8029	$1,184.75	$1,148.30	$ 36.45	3.17%	$0.8434	$0.8030	$1,872.55	$1,814.92	$ 57.63	3.18%
13	Nov 11 - Apr 12					$0.8126	$0.7926	$1,147.68	$1,129.04	$ 18.64	1.65%	$0.8129	$0.7929	$1,831.95	$1,803.41	$ 28.54	1.58%
14																	
15	Total									$ 473.61						$ 712.18	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Short Term Debt Limitations

		For Purposes of Fuel Financing
Total Direct Gas Costs	$	61,876,339
Total Indirect Gas Costs		3,616,575
Total Gas Costs	$	65,492,914
% of Debt to Total Gas Costs		30%
Short Term Debt	$	19,647,874

		For Purposes Other Than Fuel Financing
12/1/2011 Projected Net Plant	$	261,759,560
% of Debt to Net Plant		20%
Short Term Debt	$	52,351,912

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Fixed Price Option

Calculation of 2010/11 Company Allowance Reallocation Surcharge and Credit

1	Estimated 2010-11 Company Allowance Reallocation	$132,266	Sched. 25 Page 2 Line 20
2			
3	Projected Annual Transportation Througput	58,287,654	Sched. 10B Line 35
4			
5	Projected Annal Bundled Sales Thgoughput	105,300,939	Sched. 10B Line 23
6			
7	Transportation Surcharge	0.0023	Line 1 / Line 3
8			
9	Bundled Sales Credit	(0.0013)	(Line 1) / Line 5

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Fixed Price Option

EnergyNorth Company Allowance Analysis
Impact on Sales and Transportation Customers

Line NO.		Description	Average Yearly Amount	Nov-Oct 2010-2011	Nov-Oct 2009-2010	Nov-Oct 2008-2009	Nov-Oct 2007-2008	Nov-Oct 2006-2007	Nov-Oct 2005-2006	Nov-Oct 2004-2005	Nov-Oct 2003-2004	Nov-Oct 2002-2003	Nov-Oct 2001-2002
1	Actual Company Allowance			1.7%	2.3%	2.8%	2.1%	2.5%	2.9%	1.7%	2.9%	3.9%	1.6%
2	Applied Fixed Company Allowance			1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
3													
4	Commodity Cost of Gas			$0.4767	$0.5233	$0.5194	$0.9572	$0.7585	$0.8713	$0.8174	$0.6208	$0.5083	$0.3036
5													
6	Throughput Volumes - Therms												
7	Actual Firm Sales			101,884,741	93,944,063	106,439,412	106,230,353	111,233,253	107,100,702	115,409,737	118,580,624	95,422,430	76,740,166
8	Actual Firm Transportation			53,286,737	49,171,978	46,010,269	41,298,943	32,145,444	28,518,306	25,140,170	25,559,311	25,170,383	23,763,053
9	Total Actual Firm Throughput			155,171,478	143,116,041	152,449,681	147,529,297	143,378,697	135,619,008	140,549,907	144,139,935	120,592,812	100,503,219
10													
11	Transportation Company Allowance Volumes- Therms												
12	At fixed 1.2% (therms)	Line 2 * Line 8		639,441	590,064	552,123	495,587	385,745	342,220	301,682	306,712	302,045	285,157
13	At Actual Company Allowance	Line 1 * Line 8		916,928	1,120,858	1,308,843	875,535	794,357	817,832	436,372	747,734	988,382	373,591
14	Incremental Volumes- Therms	Line 13 - Line 12		277,487	530,794	756,719	379,948	408,612	475,612	134,690	441,023	686,337	88,434
15													
16													
17	Cost of Incremental Company Allowance	Line 14 * Line 4	$265,063	$132,266	$277,765	$393,057	$363,687	$309,914	$414,397	$110,094	$273,771	$348,834	$26,846
18													
19	Impact on COG Factor												
20	Increase to Sales	Line 17	$265,063	$132,266	$277,765	$393,057	$363,687	$309,914	$414,397	$110,094	$273,771	$348,834	$26,846
21	Throughput	Line 7	103,298,548	101,884,741	93,944,063	106,439,412	106,230,353	111,233,253	107,100,702	115,409,737	118,580,624	95,422,430	76,740,166
22	Impact on COG Factor	Line 20/Line 21	0.0026	$0.0013	$0.0030	$0.0037	$0.0034	$0.0028	$0.0039	$0.0010	$0.0023	$0.0037	$0.0003
23													
24	Impact on Residential using 1250 therms	Line 22 * 1250	$3.21	$1.62	$3.70	$4.62	$4.28	$3.48	$4.84	$1.19	$2.89	$4.57	$0.44
25	Annual Bill		$1,592	$1,577	$1,619	$1,726	$1,949	$1,868	$1,822	$1,631	$1,456	$1,255	$1,017
26	%	Line 24/Line 25	0.2%	0.1%	0.2%	0.3%	0.2%	0.2%	0.3%	0.1%	0.2%	0.4%	0.0%
27													
28	Monthly impact	Line 24/12	$0.27	$0.14	$0.31	$0.38	$0.36	$0.29	$0.40	$0.10	$0.24	$0.38	$0.04
29													

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2011 - 2012 Winter Cost of Gas Filing
Fixed Price Option

EnergyNorth 2011-12 Company Allowance Calculation

	Jul-2010	Aug-2010	Sep-2010	Oct-2010	Nov-2010	Dec-2010	Jan-2011	Feb-2011	Mar-2011	Apr-2011	May-2011	Jun-2011	Total
Total Sendout- Therms	4,580,810	4,884,610	5,095,560	9,717,620	15,175,970	23,550,080	27,190,120	23,255,440	19,863,250	11,693,880	7,082,540	5,216,920	157,306,800
Total Throughput- Therms	5,052,907	4,502,779	4,890,572	5,754,219	10,361,643	17,050,246	24,055,487	25,871,205	22,920,411	18,006,157	10,119,456	6,583,056	155,168,138
Variance	(472,097)	381,831	204,988	3,963,401	4,814,327	6,499,834	3,134,633	(2,615,765)	(3,057,161)	(6,312,277)	(3,036,916)	(1,366,136)	2,138,662
Company Allowance													**1.4%**