1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										1,523,054	1.7%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
13	Lost Gas (Unaccounted for)		-	154,267	268,126	327,942	293,688	236,282	128,807		1,409,112
14	Company Use		-	12,474	21,681	26,518	23,748	19,106	10,415		113,942
15	Unbilled Therms		-	7,690,884	3,532,300	1,793,136	(1,655,946)	(2,237,735)	(3,723,353)	(5,414,970)	(15,684)
16											
17	**Total Firm Volumes**	Sch. 6, ln 94	-	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276		87,958,623
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 64	-	796,342	878,932	897,468	806,735	883,624	543,941		4,807,042
22	Niagara Supply	Sch. 6, ln 65	-	625,459	690,589	705,153	633,501	694,276	636,296		3,985,274
23	TGP Supply (Direct)	Sch. 6, ln 66	-	4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382		16,183,681
24	Dracut Supply 1 - Baseload	Sch. 6, ln 67	-	-	2,648,210	4,507,009	3,037,758	-	-		10,192,978
25	Dracut Supply 2 - Swing	Sch. 6, ln 68	-	2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232		11,732,071
26	ENGIE COMBO	Sch. 6, ln 69	-	-	945,993	1,229,648	1,264,827	734,441	-		4,174,908
27	LNG Truck	Sch. 6, ln 70	-	18,690	289,648	685,485	1,029,982	145,597	-		2,169,402
28	Propane Truck	Sch. 6, ln 71	-	-	-	356,219	91,328	-	-		447,548
29	PNGTS	Sch. 6, ln 72	-	198,251	197,617	108,541	146,415	191,500	201,686		1,044,010
30	Portland Natural Gas	Sch. 6, ln 73		345,771	381,679	389,728	350,092	383,716	260,087		2,111,074
31	TGP Supply (Z4)	Sch. 6, ln 74	-	1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079		12,999,054
32	Subtotal Pipeline Volumes		-	10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703		69,847,042
33											
34	Storage Gas:										
35	TGP Storage	Sch. 6, ln 79	-	1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558		19,841,326
36											
37	Produced Gas:										
38	LNG Vapor	Sch. 6, ln 82	-	18,690	289,648	777,271	1,029,982	64,550	19,014		2,199,156
39	Propane	Sch. 6, ln 83	-	-	-	859,588	91,328	-	-		950,916
40	Subtotal Produced Gas		-	18,690	289,648	1,636,859	1,121,310	64,550	19,014		3,150,073
41											
42	Less - Gas Refill:										
43	LNG Truck	Sch. 6, ln 88	-	(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-		(2,169,402)
44	Propane	Sch. 6, ln 89	-	-	-	(356,219)	(91,328)	-	-		(447,548)
45	TGP Storage Refill	Sch. 6, ln 90	-	(2,262,867)	-	-	-	-	-		(2,262,867)
46	Subtotal Refills		-	(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-		(4,879,817)
47											
48	Total Firm Sendout Volumes	lns 32 + 35 + 40 + 46	-	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276		87,958,623
49											

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
50	**II. Gas Costs**										**REDACTED**
51											
52	**A. Demand Costs**										
53	Supply										
54	Niagara Supply	Sch.5A, ln 12	[redacted]								
55	Subtotal Supply Demand										
56	Less Capacity Credit										
57	Net Pipeline Demand Costs										
58											
59	Pipeline:										
60	Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]								
61	Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, ln 17									
62	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18									
63	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19									
64	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20									
65	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21									
66	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22									
67	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 23									
68	Portland Natural Gas Trans Service	Sch.5A, ln 24									
69	Portland Natural Gas										
70	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 26									
71	TransCanada via Union to Portland	Sch.5A, ln 27									
72	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 28									
73	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 29									
74	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 30									
75	National Fuel FST 2358	Sch.5A, ln 31									
76	Subtotal Pipeline Demand		$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570		$ 9,738,885
77	Less Capacity Credit		(524,979)	(406,202)	(406,202)	(406,202)	(406,202)	(406,202)	(406,202)		(2,962,189)
78	Net Pipeline Demand Costs		$ 786,485	$ 998,368	$ 998,368	$ 998,368	$ 998,368	$ 998,368	$ 998,368		$ 6,776,696
79											
80	Peaking Supply:										
81	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 36	[redacted]								
82	ENGIE Demand FLS	Sch.5A, ln 37									
83	ENGIE Demand	Sch.5A, ln 38									
84	Subtotal Peaking Demand		$ -	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ -		$ 4,968,750
85	Less Capacity Credit		-	(287,393)	(287,393)	(287,393)	(287,393)	(287,393)	-		(1,436,963)
86	Net Peaking Supply Demand Costs		$ -	$ 706,358	$ 706,358	$ 706,358	$ 706,358	$ 706,358	$ -		$ 3,531,788
87											
88	Storage:										
89	Dominion - Demand	Sch.5A, ln 48	[redacted]								
90	Dominion - Storage	Sch.5A, ln 49									
91	Honeoye - Demand	Sch.5A, ln 50									
92	National Fuel - Demand	Sch.5A, ln 51									
93	National Fuel - Capacity	Sch.5A, ln 52									
94	Tenn Gas Pipeline - Demand	Sch.5A, ln 53									
95	Tenn Gas Pipeline - Capacity	Sch.5A, ln 54									
96	Subtotal Storage Demand		$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317		$ 1,407,802
97	Less Capacity Credit		(281,772)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)		(485,340)
98	Net Storage Demand Costs		$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389		$ 922,462
99											
100	Total Demand Charges	lns 55 + 76 + 84 + 96	$ 2,015,366	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 1,521,887		$ 16,115,438
101	Total Capacity Credit	lns 56 + 77 + 85 + 97	(806,751)	(727,522)	(727,522)	(727,522)	(727,522)	(727,522)	(440,130)		(4,884,492)
102	Net Demand Charges		$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
103											
104							**REDACTED**				

			Peak Costs May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Peak Period Nov - Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6											
7	For Month of:										
105	**B. Commodity Costs**										**REDACTED**
106	Pipeline:										
107	Dawn Supply	Sch. 6, ln 12	[redacted]								
108	Niagara Supply	Sch. 6, ln 13									
109	TGP Supply (Direct)	Sch. 6, ln 14									
110	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
111	Dracut Supply 2 - Swing	Sch. 6, ln 16									
112	ENGIE COMBO	Sch. 6, ln 17									
113	LNG Truck	Sch. 6, ln 18									
114	Propane Truck	Sch. 6, ln 19									
115	PNGTS	Sch. 6, ln 20									
116	Portland Natural Gas	Sch. 6, ln 21									
117	TGP Supply (Z4)	Sch. 6, ln 22									
118	Subtotal Pipeline Commodity Costs		$ -	$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499		$ 42,563,780
119											
120	Storage:										
121	TGP Storage - Withdrawals	Sch. 6, ln 48	$ -	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894		$ 5,125,663
122											
123	Produced Gas Costs:										
124	LNG Vapor	Sch. 6, ln 51	[redacted]								
125	Propane	Sch. 6, ln 52									
126	Subtotal Produced Gas Costs		$ -	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567		$ 2,672,211
127											
128	Less Storage Refills:										
129	LNG Truck	Sch. 6, ln 38	[redacted]								
130	Propane	Sch. 6, ln 39									
131	TGP Storage Refill	Sch. 6, ln 40									
132	Storage Refill (Trans.)	Sch. 6, ln 41									
133	Subtotal Storage Refill		$ -	$ (765,580)	$ (131,625)	$ (809,867)	$ (600,010)	$ (65,260)	$ -		$ (2,372,341)
134											
135	Total Supply Commodity Costs		$ -	$ 2,797,420	$ 9,907,525	$ 14,220,800	$ 12,557,476	$ 6,390,132	$ 2,115,961		$ 47,989,313
136											
137	**C. Supply Volumetric Transportation Costs**										
138	Dawn Supply	Sch. 6, ln 27	[redacted]								
139	Niagara Supply	Sch. 6, ln 28									
140	TGP Supply (Direct)	Sch. 6, ln 29									
141	Dracut Supply 1 - Baseload	Sch. 6, ln 30									
142	Dracut Supply 2 - Swing	Sch. 6, ln 31									
143	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 190,287	$ 153,041	$ 162,184	$ 144,561	$ 146,577	$ 38,525		$ 835,174
144											
145	TGP Storage - Withdrawals	Sch. 6, ln 33	$ -	$ 25,361	$ 60,588	$ 75,479	$ 75,113	$ 54,742	$ 449		$ 291,733
146											
147	Total Supply Volumetric Trans. Costs	lns 143 + 145	$ -	$ 215,648	$ 213,629	$ 237,663	$ 219,674	$ 201,319	$ 38,974		$ 1,126,907
148											
149	Total Commodity Gas & Trans. Costs	lns 135 + 147	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
150											
151											

REDACTED

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln			Peak Costs								Peak Period
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
152	**D. Supply and Demand Costs by Source**										**REDACTED**
153											
154	Purchased Gas Demand Costs										
155	Pipeline Gas Demand Costs	lns 55 + 76	$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570		$ 9,738,885
156	Peaking Gas Demand Costs	ln 84	-	993,750	993,750	993,750	993,750	993,750	-		4,968,750
157	Subtotal Purchased Gas Demand Costs		$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570		$ 14,707,635
158	Less Capacity Credit	lns 56 + 77 + 85	(524,979)	(693,594)	(693,594)	(693,594)	(693,594)	(693,594)	(406,202)		(4,399,152)
159	Net Purchased Gas Demand Costs		$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368		$ 10,308,483
160											
161	Storage Gas Demand Costs										
162	Storage Demand	ln 96	$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317		$ 1,407,802
163	Less Capacity Credit	ln 97	(281,772)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)		(485,340)
164	Net Storage Demand Costs		$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389		$ 922,462
165											
166	**Total Demand Costs**	lns 159 + 164	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
167											
168	Purchased Gas Supply										
169	Commodity Costs	ln 118	$ -	$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499		$ 42,563,780
170	Less Storage Inj.(TGP Storage)	ln 131	[redacted]								
171	Less Storage Transportation	ln 132									
172	Less LNG Truck	ln 129									
173	Less Propane Truck	ln 130									
174	Plus Transportation Costs	ln 143									
175	Subtotal Purchased Gas Supply		$ -	$ 2,527,981	$ 8,837,950	$ 11,224,354	$ 10,752,485	$ 5,545,818	$ 2,138,024		$ 41,026,613
176											
177	Storage Commodity Costs										
178	Commodity Costs	ln 121	$ -	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894		$ 5,125,663
179	Transportation Costs	ln 145	-	25,361	60,588	75,479	75,113	54,742	449		291,733
180	Subtotal Storage Commodity Costs		$ -	$ 470,947	$ 1,125,101	$ 1,401,627	$ 1,394,830	$ 1,016,547	$ 8,344		$ 5,417,397
181											
182	Produced Gas Commodity Costs	ln 126	$ -	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567		$ 2,672,211
183											
184	**Subtotal Commodity Costs**	lns 175 + 180 + 182	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
185											
186	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
187											
188	**Total Commodity Costs**	lns 184 + 186	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
189											
190	**Total Demand Costs**	ln 102	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
191	**Total Supply Costs**	ln 188	-	3,013,068	10,121,153	14,458,463	12,777,150	6,591,451	2,154,935		49,116,221
192											
193	**Total Direct Gas Costs**	lns 190 + 191	$ 1,208,615	$ 4,801,183	$ 11,909,268	$ 16,246,578	$ 14,565,265	$ 8,379,566	$ 3,236,692		$ 60,347,167
194											
195							**REDACTED**				

Line	Supplier (a)	Contract (b)	Contract Type (c)	Contract Unit (d)	Unit Dth (MDQ/ACQ) (e)	Peak Period Cost per Unit Dth (f)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**					
2						
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**					
4	**Contracts Ranked on a per Unit Cost Basis**					
5						
6						
7						
8						
9	**Demand Costs**					
10	ENGIE Demand FLS		Peaking	MDQ	3,000	[redacted]
11	Niagara Supply		Supply	MDQ	3,199	
12	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
13	Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
14	National Fuel - Capacity Reservation	FSS-O02357	Storage	ACQ	670,800	
15	Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-O02357	Storage	MDQ	6,098	
18	National Fuel	FST N02358	Transportation	MDQ	6,098	
19	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
20	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
21	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
22	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
23	Tenn Gas Pipeline	95346 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	Firm Transportation	Transportation	MDQ	30,000	
29	ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
30	TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	1,784	
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	FTN-ENN0005	Transportation	MDQ	1,000	
34	Portland Natural Gas	FTN	Transportation	MDQ	1,784	
35	ENGIE Demand	NSB041	Peaking	MDQ	10,000	
36						
37	**Supply Costs - Commodity**					
38	TGP Supply (Z4)		Pipeline	Dkt	1,299,905	[redacted]
39	Niagara Supply		Pipeline	Dkt	398,527	
40	ENGIE COMBO		Pipeline	Dkt	417,491	
41	TGP Supply (Direct)		Pipeline	Dkt	1,618,368	
42	Dawn Supply		Pipeline	Dkt	480,704	
43	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	
44	TGP Storage		Storage	Dkt	1,984,133	
45	PNGTS		Pipeline	Dkt	104,401	
46	Propane Truck		Pipeline	Dkt	44,755	
47	LNG Truck		Pipeline	Dkt	216,940	
48	Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	
49	Propane		Produced	Dkt	95,092	
50	LNG Vapor (Storage)		Produced	Dkt	219,916	
51						
52	**Supply Costs - Volumetric Transportation**					
53	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	[redacted]
54	Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	
55	Niagara Supply		Pipeline	Dkt	398,527	
56	Dawn Supply		Pipeline	Dkt	480,704	
57	TGP Storage - Withdrawals		Pipeline	Dkt	1,984,133	
58	TGP Supply (Direct)		Pipeline	Dkt	1,618,368	

		Prior Period Bal Apr-18 Ending Bal Plus May B llings	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Peak Period Total
	Days in Month		31	30	31	31	30	31	30	31	31	28	31	30	31	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	( )	(m)	(n)	(o)	(p)	(q)
Account 1920 1740 COG (Over)/Under Balance Interest Calculation																
Beginning Balance	Account 1920-1740 1/	2,599,354	2,599,354	2,809,963	3,021,267	1,170,522	1,376,547	1,583,143	1,790,657	(79,923)	171,838	2,647,667	5,581,094	3,681,093	1,307,916	2,599,354
Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		201,436	201,436	201,436	201,436	201,436	201,436	4,801,183	11,909,268	16,246,578	14,565,265	8,379,566	3,236,692	-	60,347,166
Production & Storage & Misc Overhead			-	-	-	-	-	-	331,852	331,852	331,852	331,852	331,852	331,852		1,991,109
Projected Revenues w/o Int.	In 52 * 59		-	-	-	-	-	-	(1,215,530)	(8,859,482)	(12,569,565)	(13,494,227)	(11,477,743)	(7,974,343)	(3,714,669)	(59,305,560)
Projected Unb lled Revenue									(5,275,947)	(7,699,104)	(8,929,195)	(7,793,217)	(6,258,130)	(3,703,910)		(39,659,503)
Reverse Prior Month Unbilled										5,275,947	7,699,104	8,929,195	7,793,217	6,258,130	3,703,910	39,659,503
Adjustment				-	(2,059,732)				-							(2,059,732)
Add Net Adjustments	Schedule 4		-	-	-	-	-	-	(515,120)	(706,884)	(307,129)	383,528	(682,508)	(528,763)	-	(2,356,877)
Gas Cost Billed	Account 1920-1740 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Monthly (Over)/Under Recovery		2 599 354	2 800 790	3 011 398	1 162 971	1 371 958	1 577 983	1 784 579	(82 906)	171 673	2 643 482	5 570 062	3 667 347	1 300 750	1 297 157	1 215 460
Average Monthly Balance	(In 12 + 21)/2		2,700,072	2,910,681	2,092,119	1,271,240	1,477,265	1,683,861	853,875	45,875	1,407,660	4,108,865	4,624,221	2,490,921	1,302,536	
Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Interest Applied	In 22 * In 24 / 365 * Days of Month		9,173	9,868	7,552	4,589	5,160	6,078	2,983	166	4,184	11,032	13,746	7,166	-	81,696
(Over)/Under Balance	In 21 + In 26	2,599,354	2,809,963	3,021,267	1,170,522	1,376,547	1,583,143	1,790,657	(79,923)	171,838	2,647,667	5,581,094	3,681,093	1,307,916	1,297,157	1,297,157
Calculation of COG with Interest																
Beginning Balance	In 12	2,599,354	2,599,354	2,809,963	3,021,267	1,170,522	1,376,547	1,583,143	1,790,657	(81,814)	166,646	2,638,436	5,568,246	3,665,323	1,290,529	2,599,354
Fcst Direct Gas Costs(Inc U/G Hedges)	In 13		201,436	201,436	201,436	201,436	201,436	201,436	4,801,183	11,909,268	16,246,578	14,565,265	8,379,566	3,236,692	-	60,347,166
Prod Storage & Misc Overhead	In 14		-	-	-	-	-	-	331,852	331,852	331,852	331,852	331,852	331,852	-	1,991,109
Projected Revenues with int.	In 52 * In 61		-	-	-	-	-	-	(1,215,885)	(8,862,065)	(12,573,229)	(13,498,161)	(11,481,090)	(7,976,668)	(3,715,752)	(59,322,850)
Projected Unb lled Revenue									(5,277,485)	(7,701,349)	(8,931,798)	(7,795,489)	(6,259,955)	(3,704,990)		(39,671,065)
Reverse Prior Month Unbilled										5,277,485	7,701,349	8,931,798	7,795,489	6,259,955	3,704,990	39,671,065
Add Net Adjustments	In 19		-	-	(2,059,732)	-	-	-	(515,120)	(706,884)	(307,129)	383,528	(682,508)	(528,763)	-	(4,416,609)
Gas Cost Billed	In 20	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Add Interest	In 26		-	-	-	-	-	-	2,983	166	4,184	11,032	13,746	7,166	-	39,276
(Over)/Under Balance		2,599,354	2,800,790	3,011,398	1,162,971	1,371,958	1,577,983	1,784,579	(81,816)	166,658	2,638,451	5,568,261	3,665,345	1,290,566	1,279,766	1,237,446
Average Monthly Balance			2,700,072	2,910,681	2,092,119	1,271,240	1,477,265	1,683,861	854,421	42,422	1,402,548	4,103,348	4,616,795	2,477,945	1,285,148	
Interest Applied	In 24 * In 44 / 365 * Days of Month		9,173	9,868	7,552	4,589	5,160	6,078	2,985	153	4,169	11,017	13,724	7,128	-	81,596
(Over)/Under Balance	-In 41 +In 42 + In 46	2,599,354	2,809,963	3,021,267	1,170,522	1,376,547	1,583,143	1,790,657	(81,814)	166,646	2,638,436	5,568,246	3,665,323	1,290,529	1,279,766	1,279,766
Forecast Sendout Therms	Sch 1								9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276		87,958,623
Less Forecast Bi ling Therm Sales	Sch. 10B, In 23 Nov - May								1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
Less Forecast Unaccounted For	Sch 1								154,267	268,126	327,942	293,688	236,282	128,807		1,409,112
Less Forecast Company Use	Sch 1								12,474	21,681	26,518	23,748	19,106	10,415		113,942
Unbilled Volumes									7,690,884	3,532,300	1,793,136	-1,655,946	-2,237,735	-3,723,353	-5,414,970	(15,684)
Gross Unbilled									7,690,884	11,223,184	13,016,320	11,360,374	9,122,639	5,399,286	-15,684	
COB w/o Interest	Sch. 3, pg. 4, In 209 col. (c)								0.6860	0.6860	0.6860	0.6860	0.6860	0.6860	0.6860	
COG With Interest	Sch. 3, pg. 4, In 209 col. (d)								0.6862	0.6862	0.6862	0.6862	0.6862	0.6862	0.6862	

1/ Beginning Balance for Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
2/ Gas Cost Billed Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

		Prior Period Bal Apr-18 Ending Bal + May Collections	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Peak Period Total
	Days in Month		31	30	31	31	30	31	30	31	31	28	31	30	31	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	( )	(k)	(l)	(m)	(n)	(o)		(p)
Account 1163 1422 Working Capital (Over)/Under Balance Interest Calculation																
Beginning Balance	Account 1163-1422 1/	4,305	4,305	4,635	4,976	(3,267)	(2,943)	(2,618)	(2,292)	5	9,947	20,158	29,350	32,214	31,996	4,305
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		
Prime Rate			4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Forecast Working Capital	In 34 * 0.091%		315	325	335	335	335	335	7,979	19,792	22,236	19,935	11,469	4,430	-	87,820
Projected Revenues w/o Int.	In 119 * In 123		-	-	-	-	-	-	(1,063)	(7,749)	(10,994)	(11,803)	(10,039)	(6,975)	(3,249)	(51,871)
Projected Unb lled Revenue									(4,615)	(6,734)	(7,810)	(6,816)	(5,474)	(3,240)		(34,688)
Reverse Prior Month Unbilled										4,615	6,734	7,810	6,816	5,474	3,240	34,688
Add Net Adjustments			-	-	(8,581)	-	-	-	-	-	-	-	-	-	-	(8,581)
Working Capital Billed	Account 1163-1422 2/	-														-
Monthly (Over)/Under Recovery		4,305	4,620	4,960	(3,270)	(2,932)	(2,608)	(2,283)	9	9,930	20,114	29,284	32,123	31,903	31,986	31,673
Average Monthly Balance	(In 76 + In 90)/2		4,463	4,798	853	(3,099)	(2,776)	(2,451)	(1,141)	4,967	15,030	24,721	30,737	32,059	31,991	
Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Interest Applied	In 92 * In 94 / 365 * Days of Month		15	16	3	(11)	(10)	(9)	(4)	18	45	66	91	92	-	313
(Over)/Under Balance	In 90 + In 96	4,305	4,635	4,976	(3,267)	(2,943)	(2,618)	(2,292)	5	9,947	20,158	29,350	32,214	31,996	31,986	31,986

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.
2 d/b/a Liberty Utilities
3 Peak 2018 2019 Winter Cost of Gas Filing
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

101 **Calculation of Working Capital with Interest**
102

103	**Beginning Balance**	ln 76	$ 4,305	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 4,305
104	Forecast Working Capital	ln 80		315	325	335	335	335	335	7,979	19,792	22,236	19,935	11,469	4,430	-	87,820
105	Projected Rev. with interest	ln 119 * ln 125		-	-	-	-	-	-	(1,063)	(7,749)	(10,994)	(11,803)	(10,039)	(6,975)	(3,249)	(51,871)
106	Projected Unb lled Revenue									(4,615)	(6,734)	(7,810)	(6,816)	(5,474)	(3,240)		(34,688)
107	Reverse Prior Month Unbilled										4,615	6,734	7,810	6,816	5,474	3,240	34,688
108	Add Net Adjustments	ln 86	-	-	-	(8,581)	-	-	-	-	-	-	-	-	-	-	(8,581)
109	Working Capital Billed	ln 88	-	-	-	-	-	-	-								-
110	Add Interest	ln 96		-	-	-	-	-	-	(4)	18	45	66	91	92	-	309
111	Monthly (Over)/Under Recovery		$ 4,305	$ 4,620	$ 4,960	$ (3,270)	$ (2,932)	$ (2,608)	$ (2,283)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,987	$ 31,981
112																	
113	Average Monthly Balance			$ 4,463	$ 4,798	$ 853	$ (3,099)	$ (2,776)	$ (2,451)	$ (1,143)	$ 4,976	$ 15,053	$ 24,754	$ 30,782	$ 32,105	$ 31,991	
114																	
115	Interest Applied	ln 94 * ln 113 / 365 * Days of Month		15	16	3	(11)	(10)	(9)	(4)	18	45	66	92	92	-	$ 314
116																	
117	**(Over)/Under Balance**	-ln 110 +ln 111 + ln 115	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,987	$ 31,987
118																	
119	Forecast Therm Sales	ln 52								1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
120	Unbilled Therm	ln 55								7,690,884	3,532,300	1,793,136	(1,655,946)	(2,237,735)	(3,723,353)		
121	Gross Unbilled									7,690,884	11,223,184	13,016,320	11,360,374	9,122,639	5,399,286		
122																	
123	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 226 col. (c)								$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
124																	
125	Working Capital Rate w/ Int	Sch 3 pg 4 ln 226 col (d)								$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	
126	1/ Beginning Balance for Acct 1163-1422. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.																
127	2/ Working Capital Billed Acct 1163-1422. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.																
128			Prior Period Bal														
129			Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	DemandPeriod
130		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
131	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	( )	(m)	(n)	(o)	(p)
132																	
133	**Account 1920 1743 Bad Debt (Over)/Under Balance Interest Calculation**																
134																	
135	Forecast Direct Gas Costs	ln 34		$ 201,436	$ 201,436	$ 201,436	$ 201,436	$ 201,436	$ 201,436	$ 4,801,183	$11,909,268	$16,246,578	$14,565,265	$ 8,379,566	$ 3,236,692	$ -	60,347,166
136	Forecast Working Capital	ln 104		315	325	335	335	335	335	12,284	19,792	22,236	19,935	11,469	4,430		92,125
137	Prior Period Balance	ln 42								433,226	433,226	433,226	433,226	433,226	433,226		2,599,354
138	Total Forecast Direct Gas Costs & Working Capital			201,751	201,761	201,771	201,771	201,771	201,771	5,246,693	12,362,286	16,702,039	15,018,425	8,824,260	3,674,348	-	60,439,291
139																	
140	**Beginning Balance**	Account 1920-1743 1/	$ (144,328)	$ (144,328)	$ (141,289)	$ (138,240)	$ (160,372)	$ (157,422)	$ (154,442)	$ (151,471)	$ (339,874)	$ (610,930)	$ (915,007)	$(1,187,048)	$ (1,464,476)	$ (1,637,860)	$ (144,328)
141																	
142	Forecast Bad Debt	ln 138 * 0.0174597638738471		3,523	3,523	3,523	3,523	3,523	3,523	91,606	215,843	291,614	262,218	154,069	64,153		1,100,640
143																	
144	Projected Revenues w/o int	ln 181 * ln 185		-	-	-	-	-	-	(52,271)	(380,984)	(540,528)	(580,291)	(493,576)	(342,920)	(159,742)	(2,550,312)
145	Projected Unb lled Revenue									(226,881)	(331,084)	(383,981)	(335,131)	(269,118)	(159,279)		(1,705,474)
146	Reverse Prior Month Unbilled										226,881	331,084	383,981	335,131	269,118	159,279	1,705,474
147																	
148	Bad Debt Billed	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
149																	
150	Add Net Adjustments		-	-	-	(25,117)	-	-	-		-	-	-	-	-	-	(25,117)
151																	
152	Monthly (Over)/Under Recovery		$ (144,328)	$ (140,805)	$ (137,767)	$ (159,834)	$ (156,849)	$ (153,899)	$ (150,920)	$ (339,017)	$ (609,218)	$ (912,742)	$ (1,184,229)	$(1,460,541)	$ (1,633,404)	$ (1,638,323)	$ (1,619,117)
153																	
154	Average Monthly Balance	(ln 140 + ln 152)/2		$ (142,566)	$ (139,528)	$ (149,037)	$ (158,610)	$ (155,660)	$ (152,681)	$ (245,244)	$ (474,546)	$ (761,836)	$ (1,049,618)	$(1,323,794)	$ (1,548,940)	$ (1,638,091)	
155																	
156	Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
157																	
158	Interest Applied	ln 154 * ln 156 / 365 * Days of Month		$ (484)	$ (473)	$ (538)	$ (573)	$ (544)	$ (551)	$ (857)	$ (1,713)	$ (2,265)	$ (2,818)	$ (3,935)	$ (4,456)		$ (19,206)
159																	
160	**(Over)/Under Balance**	ln 152 + ln 158	$ (144 328)	$ (141 289)	$ (138 240)	$ (160 372)	$ (157 422)	$ (154 442)	$ (151 471)	$ (339 874)	$ (610 930)	$ (915 007)	$ (1 187 048)	$(1 464 476)	$ (1 637 860)	$ (1 638 323)	(1 638 323)
161																	
162																	
163	**Calculation of Bad Debt with Interest**																
164																	
165	**Beginning Balance**	ln 140	$ (144,328)	$ (144,328)	$ (141,289)	$ (138,240)	$ (135,210)	$ (132,168)	$ (129,101)	$ (126,038)	$ (314,354)	$ (585,321)	$ (889,398)	$(1,161,438)	$ (1,438,867)	$ (1,612,251)	$ (144,328)
166	Forecast Bad Debt	ln 142		3,523	3,523	3,523	3,523	3,523	3,523	91,606	215,843	291,614	262,218	154,069	64,153	-	1,100,640
167	Projected Revenues with int.	ln 181 * ln 187		-	-	-	-	-	-	(52,271)	(380,984)	(540,528)	(580,291)	(493,576)	(342,920)	(159,742)	(2,550,312)
168	Projected Unb lled Revenue									(226,881)	(331,084)	(383,981)	(335,131)	(269,118)	(159,279)		(1,705,474)
169	Reverse Prior Month Unbilled										226,881	331,084	383,981	335,131	269,118	159,279	1,705,474
170	Bad Debt Billed	ln 148	-		-	-	-	-	-	-	-	-	-	-	-	-	0
171	Add Interest	ln 158		-	-	-	-	-	-	(857)	(1,713)	(2,265)	(2,818)	(3,935)	(4,456)	-	(16,043)
172	Add Net Adjustments	ln 150	-							-	-	-	-	-	-	-	0
173	Monthly (Over)/Under Recovery		$ (144 328)	$ (140 805)	$ (137 767)	$ (134 717)	$ (131 687)	$ (128 646)	$ (125 578)	$ (314 441)	$ (585 410)	$ (889 398)	$ (1 161 438)	$(1 438 867)	$ (1 612 251)	$ (1 612 714)	$ (1 610 043)
174																	
175	Average Monthly Balance			$ (142,566)	$ (139,528)	$ (136,478)	$ (133,448)	$ (130,407)	$ (127,340)	$ (220,239)	$ (449,882)	$ (737,359)	$ (1,025,418)	$(1,300,153)	$ (1,525,559)	$ (1,612,482)	
176																	
177	Interest Applied	ln 156 * ln 175 / 365 * Days of Month		(484)	(473)	(493)	(482)	(456)	(460)	(769)	(1,624)	(2,265)	(2,818)	(3,935)	(4,456)	-	$ (18,714)
178																	
179	**(Over)/Under Balance**	-ln 171 +ln 173 + ln 177	$ (144,328)	$ (141,289)	$ (138,240)	$ (135,210)	$ (132,168)	$ (129,101)	$ (126,038)	$ (314,354)	$ (585,321)	$ (889,398)	$ (1,161,438)	$(1,438,867)	$ (1,612,251)	$ (1,612,714)	$ (1,612,714)
180																	
181	Forecast Term Sales	ln 52								1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
182	Unbilled Therm	ln 55								7,690,884	3,532,300	1,793,136	(1,655,946)	(2,237,735)	(3,723,353)		
183	Gross Unbilled									7,690,884	11,223,184	13,016,320	11,360,374	9,122,639	5,399,286		
184																	
185	COG Rate Without Interest	Sch. 3, pg. 4, ln 243 col. (c)								$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	
186																	
187	COG With Interest	Sch. 3, pg. 4, ln 243 col. (d)								$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	
188	1/ Beginning Balance for Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.																
189	2/ Bad Debt B lled Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.																
190																	
191	**Total Interest**	lns 46 + 115 + 177	$ -	$ 8,704	$ 9,412	$ 7,062	$ 4,096	$ 4,695	$ 5,610	$ 2,211	$ (1,453)	$ 1,949	$ 8,266	$ 9,880	$ 2,765	$ -	$ 63,196

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

			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	Net Option Premiums	Fixed Price Option Administrative Costs	Total Adjustments
6	**Adjustments**												
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8													
9	May-18		$ -	$ -	-	$ -	$ -	$ -	[redacted]		$ -	$ -	$ -
10	Jun-18		-	-	-	-	-	-			-	-	-
11	Jul-18	1/	-	-	-	-	-	-			-	-	-
12	Aug-18	1/	-	-	-	-	-	-			-	-	-
13	Sep-18	1/	-	-	-	-	-	-			-	-	-
14	Oct-18	1/	-	-	-	-	-	-			-	-	-
15	Nov-18	1/	-	-	(227,504)	-	(3,273)	-			-	45,000	(515,120)
16	Dec-18	1/	-	-	(368,407)	-	(4,111)	-			-	-	(706,884)
17	Jan-19	1/	-	-	(17,997)	-	(5,091)	-			-	-	(307,129)
18	Feb-19	1/	-	-	703,749	-	(5,254)	-			-	-	383,528
19	Mar-19	1/	-	-	(369,992)	-	(4,696)	-			-	-	(682,508)
20	Apr-19	1/	-	-	(217,609)	-	(3,956)	-			-	-	(528,763)
21													
22	Subtotal May 18 - Oct 18		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23													
24	Subtotal Nov 18 - Apr 19		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
25													
26	Total Peak Period		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
27													

1/ Estimates are based on prior years actual, except transportation revenue is calculated on Schedule 17.

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Demand Costs**

REDACTED
Schedule 5A
Page 1 of 1

Ln		Peak	Reference	Deferred to Peak May 18 -Oct 18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov-Apr Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagara 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 95346 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	Portland Natural Gas		Sch 5B, ln 21 * Sch 5C ln 29 x days								
26	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 22 * Sch 5C ln 30 x days								
27	TransCanada via Union to Portland		Sch 5B, ln 23 * Sch 5C ln 31 x days								
28	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 24 * Sch 5C ln 32 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 25 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 36 x days								
31	National Fuel FST 2358	peak	Sch 5B, ln 27 * Sch 5C ln 38 x days								
32											
33	Subtotal Pipeline Demand Charges			$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 9,738,885
34											
35	**Peaking Supply**										
36	Tenn Gas Pipeline (Concord Latera) Z6-Z6	peak	Sch 5B, ln 30 * Sch 5C ln 26 x days	[redacted]							
37	ENGIE Demand FLS	peak	Per Contract								
38	ENGIE Demand	peak	Per Contract								
39	Subtotal Peaking Demand Charges			$ -	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ -	$ 4,968,750
40											
41	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 33 + ln 39	$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570	$ 14,707,635
42											
43	Less Transportation Capacity Credit			$ (524,979)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (406,202)	$ (4,399,152)
44											
45	**Total Supply, Pipeline & Peaking Demand**			$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368	$ 10,308,483
46											
47											
48	Dominion - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 61 x days	$ 10,464	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 20,928
49	Dominion - Storage	peak	Sch 5B, ln 36 * Sch 5C ln 62 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
50	Honeoye - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 65 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
51	National Fuel - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 67 x days	90,980	15,163	15,163	15,163	15,163	15,163	15,163	181,959
52	National Fuel - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 68 x days	153,345	25,557	25,557	25,557	25,557	25,557	25,557	306,690
53	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 41 * Sch 5C ln 71 x days	195,783	32,631	32,631	32,631	32,631	32,631	32,631	391,567
54	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 42 * Sch 5C ln 72 x days	191,928	31,988	31,988	31,988	31,988	31,988	31,988	383,856
55											
56	**Subtotal Storage Demand Costs**			$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 1,407,802
57											
58	Less Transportation Capacity Credit			$ (281,772)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (485,340)
59											
60	**Total Storage Demand Costs**		ln 56 + ln 58	$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 922,462
61											
62	**Total Demand Charges**		ln 41 + ln 56	$ 2,015,366	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 1,521,887	$ 16,115,438
63											
64	Total Transportation Capacity Credit		ln 43 + ln 58	$ (806,751)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (440,130)	$ (4,884,492)
65											
66	**Total Demand Charges less Cap. Cr.**		ln 62 + ln 64	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757	$ 11,230,946
67											

68 **REDACTED**

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Demand Volumes**

Line	(a)	Peak (b)	Reference (c)	Nov-18 (d)	Dec-18 (e)	Jan-19 (f)	Feb-19 (g)	Mar-19 (h)	Apr-19 (i)
5									
8	**Supply**								
9	Niagara Supply			3,199	3,199	3,199	3,199	3,199	3,199
10									
11	**Pipeline**								
12	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
13	Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
14	Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
15	Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
16	Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
17	Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
18	Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
19	Tenn Gas Pipeline (Concord Lateral)		Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
20	Portland Natural Gas Trans Service		FTN-ENN0005	1,000	1,000	1,000	1,000	1,000	1,000
21	Portland Natural Gas		FTN	1,784	1,784	1,784	1,784	1,784	1,784
22	ANE (TransCanada via Union to Iroquois)		Union Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
23	TransCanada via Union to Portland		Union Parkway to Portland	1,784	1,784	1,784	1,784	1,784	1,784
24	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
25	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
26	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
27	National Fuel	peak	FST N02358	6,098	6,098	6,098	6,098	6,098	6,098
28									
29	**Peaking**								
30	Tenn Gas Pipeline (Concord Lateral)	peak		0	0	0	0	0	0
31	ENGIE Demand FLS	peak		3,000	3,000	3,000	3,000	3,000	0
32	ENGIE Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	0
33									
34	**Storage**								
35	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
36	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
37	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
38	Honeoye - Capacity	peak	SS-NY	245,380	245,380	245,380	245,380	245,380	245,380
39	National Fuel - Demand	peak	FSS-O02357	6,098	6,098	6,098	6,098	6,098	6,098
40	National Fuel - Capacity Reservation	peak	FSS-O02357	670,800	670,800	670,800	670,800	670,800	670,800
41	Tenn Gas Pipeline - Demand	peak	FS-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
42	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Demand Rates

				Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov - Apr
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagara Supply		[redacted]	Per Contract	[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$5.5997	First Revised Sheet No. 4	$0.1867	$0.1806	$0.1806	$0.2000	$0.1806	$0.1867	$0.1859
Tenn Gas Pipeline	95346 Z5-Z6	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0.2386	$0.2376
Tenn Gas Pipeline	2302 Z5-Z6	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0.2386	$0.2376
Tenn Gas Pipeline	8587 Z0-Z6	$23.2175	FT-A (Z0 - Z6)	$0.7739	$0.7490	$0.7490	$0.8292	$0.7490	$0.7739	$0.7706
Tenn Gas Pipeline	8587 Z1-Z6	$20.6094	FT-A (Z1 - Z6)	$0.6870	$0.6648	$0.6648	$0.7361	$0.6648	$0.6870	$0.6841
Tenn Gas Pipeline	8587 Z4-Z6	$8.1481	FT-A (Z4 - Z6)	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2705
TGP Dracut	42076 FTA Z6-Z6	$4.7453	11th Rev Sheet No. 14	$0.1582	$0.1531	$0.1531	$0.1695	$0.1531	$0.1582	$0.1575
TGP Concord Lateral	Firm Transportatio	$12.1916	Per contract	$0.4064	$0 3933	$0.3933	$0.4354	$0.3933	$0.4064	$0.4047
Portland Natural Gas	FTN-ENN0005	$18.2633	Dmd is Negot/CMDY=Part 4.1 \	$0.6088	$0 5891	$0.5891	$0.6523	$0.5891	$0.6088	$0.6062
Portland Natural Gas	FTN	$22.8125	Dmd is Negot/CMDY=Part 4.1 \	$0.7604	$0.7359	$0.7359	$0.8147	$0.7359	$0.7604	$0.7572
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.1481	11th Rev Sheet No. 14	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2705
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.1481	11th Rev Sheet No. 14	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0 2716	$0.2705
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0 2386	$0.2376
National Fuel	FST N02358	$3.6874	4.010 Version 21.0.1 Pg 1	$0.1229	$0.1189	$0.1189	$0.1317	$0.1189	$0.1229	$0.1224
ANE Union Gas		$3.7160								
TransCanada Pipelines Limited		$13 34166	Union Parkway to Iroquois							
Delivery Pressure Demand Charge		0.6704	Union Parkway to Iroquois							
Sub Total Demand Charges		17.7280								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		1.2851	updated 7/6/18							
Demand Rate/US$		$14.5544		$0.4851	$0.4695	$0.4695	$0.5198	$0.4695	$0.4851	$0.4831
Union Gas		$3.7160								
TransCanada Pipelines Limited		$22.4898	Union Parkway to Portland							
Delivery Pressure Demand Charge		$0.6704	Union Parkway to Portland							
Sub Total Demand Charges		26.8762								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		1.2851	updated 7/6/18							
Demand Rate/US$		$22.0649		$0.7355	$0.7118	$0.7118	$0.7880	$0.7118	$0.7355	$0.7324
Peaking										
ENGIE Demand FLS		[redacted]	Per Contract	[redacted]						
Subtotal Peaking Demand Charges			Per Contract							
Storage										
Dominion - Demand	GSS 300076	$1.8672	GSS Settled,Tariff Rec #10.30 \	$0.0622	$0.0602	$0.0602	$0.0667	$0.0602	$0.0622	$0.0619
Dominion - Capacity	GSS 300076	$0.0145	GSS Settled,Tariff Rec #10.30 \	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8817		$0.0627	$0.0607	$0.0607	$0.0672	$0.0607	$0.0627	$0.0624
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0 2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Demand Rates**

					Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov - Apr
5											
67	National Fuel - Demand	FSS-O02357	$2.4866	4.020 Version 16.0.0 Pg 1	$0.0829	$0.0802	$0.0802	$0.0888	$0.0802	$0.0829	$0.0825
68	National Fuel - Capacity	FSS-O02357	$0.0381	4.020 Version 16.0.0 Pg 1	$0.0013	$0.0012	$0.0012	$0.0014	$0.0012	$0.0013	$0.0013
69			$2.5247		$0.0842	$0.0814	$0.0814	$0.0902	$0.0814	$0.0842	$0.0837
70											
71	Tenn Gas Pipeline	FS-MA 523	$1.4938	14th Rev Sheet No.61	$0.0498	$0.0482	$0.0482	$0.0534	$0.0482	$0.0498	$0.0495
72	Tenn Gas Pipeline - Space	FS-MA 523	$0.0205	14th Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007
73			$1.5143		$0.0505	$0.0488	$0.0488	$0.0541	$0.0488	$0.0505	$0.0502
74											
75											

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2017 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 26, 2018

The annual charges unit charge (ACA) to be applied to in fiscal year 2019 for recovery of FY 2018 Current year and 2017 True-Up is **$0.0013** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2018.

The following calculations were used to determine the FY 2018 unit charge:

2018 CURRENT:

Estimated Program Cost $66,791,000 divided by 49,985,774,086 Dth = 0.0013362002

2017 TRUE-UP:

Debit/Credit Cost ($316,993) divided by 47,717,356,257 Dth = (0.0000066431)

TOTAL UNIT CHARGE = 0.0013295571

If you have any questions, please contact Raven A. Rodriguez at (202)502-6276 or e-mail at Raven.Rodriguez@ferc.gov.

PUBLIC

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(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	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0665	$0.0052	($0.0050)	$0.0021	$1.8672	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0136	$0.0001	($0.0001)	$0.0290	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0001)	$0.0154	[8]
	GSS-TE Surcharge [3]	-	$0.0046	-	($0.0003)	-	$0.0043	-
	From Customers Balance	$0.6163	$0.0143	$0.0011	($0.0010)	$0.0004	$0.6311	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0665	$0.0052	($0.0050)	$0.0021	$2.2801	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0136	$0.0001	($0.0001)	$0.0290	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0001)	$0.0154	[8]
	Authorized Overruns	$1.0657	$0.0143	$0.0011	($0.0010)	$0.0004	$1.0805	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0002)	$0.0001	$0.0759	-
	Injection Charge	$0.0154	-	$0.0136	$0.0001	($0.0001)	$0.0290	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0001)	$0.0154	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0143	$0.0011	($0.0010)	$0.0004	$0.6311	[8]
	Excess Injection Charge	$0.2245	-	$0.0136	$0.0001	($0.0001)	$0.2381	-

[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 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6157. Daily Capacity Release Rate for GSS-E per Dt is $1.0651.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

Iroquois Gas Transmission System, L.P.
FERC Gas Tariff
Second Revised Volume No. 1

Third Revised Sheet No. 4
Superseding
Second Revised Sheet No. 4

---------- NON-EASTCHESTER RATES (All in $ Per Dth) 1/ ----------

	Minimum	Maximum		
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018
RTS DEMAND (Monthly):				
Zone 1	$0.0000	$ 6.1928	$ 5.9982	$ 5.5997
Zone 2	$0.0000	$ 5.3381	$ 5.1678	$ 4.7998
Inter-Zone	$0.0000	$10.4755	$ 9.8672	$ 8.8026
RTS COMMODITY (Daily):				
Zone 1	$0.0034	$ 0.0034	$ 0.0034	$ 0.0034
Zone 2	$0.0022	$ 0.0022	$ 0.0022	$ 0.0022
Inter-Zone	$0.0056	$ 0.0056	$ 0.0056	$ 0.0056
ITS COMMODITY (Daily):				
Zone 1	$0.0034	$ 0.2070	$ 0.2006	$ 0.1875
Zone 2	$0.0022	$ 0.1777	$ 0.1721	$ 0.1600
Inter-Zone	$0.0056	$ 0.3500	$ 0.3300	$ 0.2950
VOLUMETRIC CAPACITY RELEASE (Daily) 2/:				
Zone 1	$0.0000	$ 0.2036	$ 0.1972	$ 0.1841
Zone 2	$0.0000	$ 0.1755	$ 0.1699	$ 0.1578
Inter-Zone	$0.0000	$ 0.3444	$ 0.3244	$ 0.2894

**SEE SHEET NOS. 4A, 4B, AND 4C FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

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1/ Transporter's Settlement dated August 18, 2016, in Docket No. RP16-301-000, which was approved by Commission order issued October 20, 2016, established new base tariff recourse rates referred to as "Settlement Rates" and a moratorium on changes to the Settlement Rates until September 1, 2020. All recourse Maximum and Minimum Rates listed on Sheet Nos. 4, 4B, 4C, and 5A are Settlement Rates subject to the moratorium.

2/ 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.

075

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	1/

MEASUREMENT VARIANCE/FUEL USE FACTOR:

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

1/ The ACA ADJUSTMENT Commoditiy rate shall be the applicable FERC ACA unit charge incorporated by reference pursuant to Section 12.2 in the General Terms and Conditions of Transporter's FERC Gas Tariff.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Rate [2/] (3)
ESS	Demand	(Max)	$2.4921 [7/]
		(Min)	$0.0000
	Capacity	(Max)	$0.0388 [8/]
		(Min)	$0.0000
	Injection/	(Max)	$0.0411plus ACA [3/]
	Withdrawal	(Min)	$0.0000
	Max. Volumetric Dem. Rate [4/]		$0.0853plus ACA [3/]
	Max. Volumetric Cap. Rate [5/]		$0.0013
	Storage Balance Transfer	(Max)[6/]	$3.8600
		(Min) [6/]	$0.0000
ISS	Injection	(Max)	$0.9923plus ACA [3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[6/]	$3.8600
		(Min) [6/]	$0.0000
FSS	Demand	(Max)	$2.3833 [7/]
		(Min)	$0.0000
	Capacity	(Max)	$0.0366 [8/]
		(Min)	$0.0000
	Injection/	(Max)	$0.0391plus ACA [3/]
	Withdrawal	(Min)	$0.0000
	Max. Volumetric Dem. Rate [4/]		$0.0816plus ACA [3/]
	Max. Volumetric Cap. Rate [5/]		$0.0013
	Storage Balance Transfer	(Max)[6/]	$3.8600
		(Min) [6/]	$0.0000

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

2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 0.89%.

3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.

4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.

5/ Assessed per dekatherm per day on storage balance.

6/ Rate per nomination.

7/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.1033 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.

8/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0015 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

RATES FOR TRANSPORTATION SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	Current Rate [2/] (6)
FT/FT-S						
	Reservation	(Max)	$3.6293	-	-	$3.6293 [4/]
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378 plus ACA [3/]
EFT	Reservation	(Max)	3.8067	0.0000	0.0000	$3.8067 [4/]
		(Min)	0.0000	0.0000	0.0000	$0.0000
	Commodity	(Max)	0.0148	0.0000	0.0000	$0.0148 plus ACA[3/]
		(Min)	0.0148	0.0000	0.0000	$0.0148 plus ACA[3/]
	Overrun	(Max)	0.1452	-	-	$0.1452 plus ACA[3/]
		(Min)	0.0148	-	-	$0.0148 plus ACA[3/]
	Maximum Volumetric Rate		0.1452	0.0000	0.0000	$0.1452 plus ACA[3/]
FST	Reservation	(Max)	3.6293	-	-	$3.6293 [4/]
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378 plus ACA [3/]
IT	Commodity	(Max)	$0.1378	-	-	$0.1378 plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3/]
	Overrun	(Max)	0.1378	-		$0.1378 plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3/]

The NA15 Retention is 1.25% applicable to use of the Northern Access 2015 Lease. [2/ 3/]

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

2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.79% and the Transportation LAUF Retention for all applicable rate schedules is 0.00%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.

3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.

4/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0581 shall be added as a Transmission PS/GHG Surcharge, in addition to the specified rate.

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/
FT	Recourse Reservation Rate		
	-- Maximum	$25.9843	---------
	-- Minimum	$00.0000	---------
	Seasonal Recourse Reservation Rate		
	-- Maximum	$49.3701	---------
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$00.0000	2/
	-- Minimum	$00.0000	2/
FT-FLEX	Recourse Reservation Rate		
	--Maximum	$17.4406	---------
	--Minimum	$00.0000	---------
	Recourse Usage Rate		
	--Maximum	$00.2809	2/
	--Minimum	$00.0000	2/

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.

2/ The currently effective ACA unit charge as published on the Commission's website (www.ferc.gov) is incorporated herein by reference.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base
Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.5411		$11.5794	$15.5758	$15.8514	$17.4175	$18.4879	$23.1959
L		$4.9193						
1	$8.3417		$7.9962	$10.6413	$15.0745	$14.8460	$16.7429	$20.5878
2	$15.5759		$10.5774	$5.5014	$5.1427	$6.5803	$9.0504	$11.6830
3	$15.8514		$8.3784	$5.5458	$4.0009	$6.1457	$11.1149	$12.8437
4	$20.1259		$18.5544	$7.0708	$10.7456	$5.2598	$5.6884	$8.1265
5	$23.9973		$16.8625	$7.4172	$8.9748	$5.8432	$5.4810	$7.1353
6	$27.7603		$19.3678	$13.3296	$14.6845	$10.3726	$5.4568	$4.7237

Daily Base
Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1822		$0.3807	$0.5121	$0.5211	$0.5726	$0.6078	$0.7626
L		$0.1617						
1	$0.2742		$0.2629	$0.3499	$0.4956	$0.4881	$0.5505	$0.6769
2	$0.5121		$0.3478	$0.1809	$0.1691	$0.2163	$0.2975	$0.3841
3	$0.5211		$0.2755	$0.1823	$0.1315	$0.2021	$0.3654	$0.4223
4	$0.6617		$0.6100	$0.2325	$0.3533	$0.1729	$0.1870	$0.2672
5	$0.7890		$0.5544	$0.2439	$0.2951	$0.1921	$0.1802	$0.2346
6	$0.9127		$0.6367	$0.4382	$0.4828	$0.3410	$0.1794	$0.1553

Maximum Reservation
Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.5627		$11.6010	$15.5974	$15.8730	$17.4391	$18.5095	$23.2175
L		$4.9409						
1	$8.3633		$8.0178	$10.6629	$15.0961	$14.8676	$16.7645	$20.6094
2	$15.5975		$10.5990	$5.5230	$5.1643	$6.6019	$9.0720	$11.7046
3	$15.8730		$8.4000	$5.5674	$4.0225	$6.1673	$11.1365	$12.8653
4	$20.1475		$18.5760	$7.0924	$10.7672	$5.2814	$5.7100	$8.1481
5	$24.0189		$16.8841	$7.4388	$8.9964	$5.8648	$5.5026	$7.1569
6	$27.7819		$19.3894	$13.3512	$14.7061	$10.3942	$5.4784	$4.7453

Notes:

1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0216.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Thirteenth Revised Sheet No. 15
Superseding
Twelveth Revised Sheet No. 15

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base
Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2668	$0.2546	$0.3030
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2269	$0.2313	$0.2641
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0734	$0.1178	$0.1305
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0982	$0.1358	$0.1482
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0454	$0.0642	$0.1041
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0639	$0.0633	$0.0787
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0984	$0.0533	$0.0324

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0041		$0.0124	$0.0186	$0.0228	$0.2677	$0.2555	$0.3039
L		$0.0021						
1	$0.0051		$0.0090	$0.0156	$0.0188	$0.2278	$0.2322	$0.2650
2	$0.0176		$0.0096	$0.0021	$0.0037	$0.0743	$0.1187	$0.1314
3	$0.0216		$0.0178	$0.0035	$0.0011	$0.0991	$0.1367	$0.1491
4	$0.0259		$0.0214	$0.0096	$0.0114	$0.0463	$0.0651	$0.1050
5	$0.0293		$0.0265	$0.0109	$0.0127	$0.0648	$0.0642	$0.0796
6	$0.0355		$0.0309	$0.0152	$0.0172	$0.0993	$0.0542	$0.0333

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.

3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0009.

Issued: September 27, 2016
Effective: November 1, 2016

Docket No. RP16-1251-000
Accepted: October 13, 2016

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.0334	$2.0334 1/		
Space Rate	$0.0207	$0.0207 1/		
Injection Rate	$0.0073	$0.0073	1.51%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.2441	$0.2441 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.4938	$1.4938 1/		
Space Rate	$0.0205	$0.0205 1/		
Injection Rate	$0.0087	$0.0087	1.51%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1793	$0.1793 1/		

Notes:

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to -0.09%.

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.51%		1.54%	2.28%	2.86%	3.33%	3.75%	4.44%
L		0.26%						
1	0.63%		1.12%	1.92%	2.31%	2.82%	3.41%	3.88%
2	2.33%		1.19%	0.25%	0.46%	0.85%	1.43%	1.93%
3	2.86%		2.31%	0.46%	0.14%	1.17%	1.69%	2.20%
4	3.33%		2.62%	1.19%	1.41%	0.48%	0.73%	1.24%
5	3.88%		3.41%	1.44%	1.69%	0.72%	0.71%	0.91%
6	4.63%		4.02%	1.93%	2.20%	1.17%	0.57%	0.30%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0039		$0.0151	$0.0233	$0.0290	$0.0350	$0.0398	$0.0477
L		$0.0013						
1	$0.0053		$0.0105	$0.0193	$0.0236	$0.0293	$0.0359	$0.0412
2	$0.0233		$0.0113	$0.0012	$0.0034	$0.0076	$0.0138	$0.0190
3	$0.0290		$0.0236	$0.0034	$0.0000	$0.0111	$0.0164	$0.0219
4	$0.0350		$0.0271	$0.0113	$0.0137	$0.0036	$0.0063	$0.0118
5	$0.0398		$0.0359	$0.0138	$0.0164	$0.0062	$0.0061	$0.0082
6	$0.0477		$0.0412	$0.0190	$0.0219	$0.0110	$0.0046	$0.0017

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.10%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.10%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

Interim Mainline 2018 Transportation Tolls and 2018 Abandonment Surcharges (TGI-003-2017)

Storage Transportation Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
1	Centram MDA	5.10726	0.1679	0.30417	0.0100
2	Union WDA	34.53326	1.1353	2.87711	0.0946
3	Union NDA	14.71771	0.4839	1.05728	0.0348
4	Union EDA	10.29604	0.3385	0.65092	0.0214
5	KPUC EDA	9.90367	0.3256	0.61503	0.0202
6	GMIT EDA	16.93265	0.5567	1.26047	0.0414
7	Enbridge CDA	5.26756	0.1732	0.18919	0.0062
8	Enbridge EDA	13.18532	0.4335	0.91645	0.0301
9	Cornwall	13.37938	0.4399	0.93410	0.0307
10	Iroquois	12.57212	0.4133	0.86018	0.0283
11	Philipsburg	16.97676	0.5581	1.26473	0.0416

Firm Transportation - Short Notice

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
12	Kirkwall to Thorold CDA	6.06965	0.1996	0.21292	0.0070
13	Union Parkway Belt to Goreway CDA	4.51931	0.1486	0.08213	0.0027
14	Union Parkway Belt to Victoria Square #2 CDA	5.33691	0.1755	0.15208	0.0050
15	Union Parkway Belt to Schomberg #2 CDA	5.28368	0.1737	0.14600	0.0048
16	Union Parkway Belt to Napanee #2 EDA	10.18928	0.3350	0.54446	0.0179

Dawn Long Term Fixed Price

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
17	For All Dawn LTFP Contract Demand except any portion subject to a reduced term for the final 24 months of such reduced term	23.42083	0.7700
18	Any portion of Contract Demand reduced in term by 12 months for months 85 through 108	26.46250	0.8700
19	Any portion of Contract Demand reduced in term by 24 months for months 73 through 96	28.89583	0.9500
20	Any portion of Contract Demand reduced in term by 36 months for months 61 through 84	30.41667	1.0000
21	Any portion of Contract Demand reduced in term by 48 months for months 49 through 72	31.63333	1.0400
22	Any portion of Contract Demand reduced in term by 60 months for months 37 through 60	31.93750	1.0500

Notes: The tolls are inclusive of Delivery Pressure Toll and Abandonment Surcharge.
The Abandonment Surcharges are the same as the Empress to Emerson 2 Abandonment Surcharges for FT service.

Enhanced Market Balancing Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
1	Union Parkway Belt to Union EDA	11.32565	0.3724	0.65092	0.0214

Delivery Pressure

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
2	Average Delivery Pressure Toll	0.67038	0.0220

Note: Delivery Pressure toll applies to the following locations: Emerson 1 , Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford.
The Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, STFT and SSS.

Union Dawn Receipt Point Surcharge

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
3	Union Dawn Receipt Point Surcharge	0.14587	0.0048

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
4	SNB Toll	3.43648	0.1130

Note: This SNB Toll is a representative toll for the Eastern Region.

Energy Deficient Gas Allowance (EDGA) Service

Line No.	Particulars	Capacity Charge ($/GJ/D)
	(a)	(b)
5	Western Section	1.4886
6	Eastern Section	0.3640

Note: The EDGA Service capacity charge for the Western Section is the effective Empress to North Bay Junction FT Toll and the capacity charge for the Eastern Section is the effective Parkway to North Bay Junction FT Toll.
The EDGA Service fuel charge for the Western Section includes the effective Empress to North Bay Junction monthly fuel ratio and the fuel charge for the Eastern Section includes the effective Parkway to North Bay Junction monthly fuel ratio.

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/Month)	Daily Equivalent FT for IT / STFT ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
1	Union NDA	Enbridge CDA	-	0.3946	-	0.0343
2	Union NDA	Enbridge Parkway CDA	-	0.3986	-	0.0348
3	Union NDA	Enbridge EDA	-	0.4283	-	0.0381
4	Union NDA	KPUC EDA	-	0.5045	-	0.0466
5	Union NDA	GMIT EDA	-	0.5546	-	0.0521
6	Union NDA	Enbridge SWDA	-	0.5278	-	0.0492
7	Union NDA	Union SWDA	-	0.5299	-	0.0494
8	Union NDA	Chippawa	-	0.4756	-	0.0433
9	Union NDA	Cornwall	-	0.4586	-	0.0414
10	Union NDA	East Hereford	-	0.6614	-	0.0641
11	Union NDA	Emerson 1	-	0.9288	-	0.0992
12	Union NDA	Emerson 2	-	0.9288	-	0.0992
13	Union NDA	Iroquois	-	0.4397	-	0.0393
14	Union NDA	Kirkwall	-	0.4204	-	0.0372
15	Union NDA	Napierville	-	0.5461	-	0.0512
16	Union NDA	Niagara Falls	-	0.4742	-	0.0432
17	Union NDA	North Bay Junction	-	0.1848	-	0.0120
18	Union NDA	Philipsburg	-	0.5561	-	0.0523
19	Union NDA	Spruce	-	0.8519	-	0.0902
20	Union NDA	St. Clair	-	0.5149	-	0.0507
21	Union NDA	Welwyn	-	1.0634	-	0.1150
22	Union NDA	Dawn Export	-	0.5278	-	0.0492
23	Union Parkway Belt	Empress	63.22226	2.0785	5.51241	0.1812
24	Union Parkway Belt	TransGas SSDA	54.10243	1.7787	4.67474	0.1537
25	Union Parkway Belt	Centram SSDA	50.36574	1.6559	4.33164	0.1424
26	Union Parkway Belt	Centram MDA	44.71341	1.4700	3.81243	0.1253
27	Union Parkway Belt	Centrat MDA	44.27389	1.4556	3.77197	0.1240
28	Union Parkway Belt	Union WDA	34.53326	1.1353	2.87711	0.0946
29	Union Parkway Belt	Nipigon WDA	30.53408	1.0039	2.50998	0.0825
30	Union Parkway Belt	Union NDA	14.71771	0.4839	1.05728	0.0348
31	Union Parkway Belt	Calstock NDA	23.58052	0.7753	1.87123	0.0615
32	Union Parkway Belt	Tunis NDA	18.10674	0.5953	1.36845	0.0450
33	Union Parkway Belt	GMIT NDA	14.03851	0.4615	0.99463	0.0327
34	Union Parkway Belt	Union SSMDA	21.07662	0.6929	1.64128	0.0540
35	Union Parkway Belt	Union NCDA	7.38395	0.2428	0.38355	0.0126
36	Union Parkway Belt	Union CDA	4.79732	0.1577	0.14600	0.0048
37	Union Parkway Belt	Union ECDA	3.75676	0.1235	0.05049	0.0017
38	Union Parkway Belt	Union EDA	10.29604	0.3385	0.65092	0.0214
39	Union Parkway Belt	Union Parkway Belt	3.51465	0.1156	0.02798	0.0009
40	Union Parkway Belt	Enbridge CDA	5.26756	0.1732	0.18919	0.0062
41	Union Parkway Belt	Enbridge Parkway CDA	3.51465	0.1156	0.02798	0.0009
42	Union Parkway Belt	Enbridge EDA	13.18532	0.4335	0.91645	0.0301
43	Union Parkway Belt	KPUC EDA	9.90367	0.3256	0.61503	0.0202
44	Union Parkway Belt	GMIT EDA	16.93265	0.5567	1.26047	0.0414
45	Union Parkway Belt	Enbridge SWDA	8.28428	0.2724	0.46629	0.0153
46	Union Parkway Belt	Union SWDA	8.35972	0.2748	0.47328	0.0156
47	Union Parkway Belt	Chippawa	6.35435	0.2089	0.28896	0.0095
48	Union Parkway Belt	Cornwall	13.37938	0.4399	0.93410	0.0307
49	Union Parkway Belt	East Hereford	20.86766	0.6861	1.62212	0.0533
50	Union Parkway Belt	Emerson 1	41.71007	1.3713	3.53655	0.1163
51	Union Parkway Belt	Emerson 2	41.71007	1.3713	3.53655	0.1163
52	Union Parkway Belt	Iroquois	12.48908	0.4106	0.85258	0.0280
53	Union Parkway Belt	Kirkwall	4.31795	0.1420	0.10190	0.0034
54	Union Parkway Belt	Napierville	16.60963	0.5461	1.23096	0.0405
55	Union Parkway Belt	Niagara Falls	6.30416	0.2073	0.28440	0.0094
56	Union Parkway Belt	North Bay Junction	11.07136	0.3640	0.72209	0.0237
57	Union Parkway Belt	Philipsburg	16.97676	0.5581	1.26473	0.0416
58	Union Parkway Belt	Spruce	44.27389	1.4556	3.77197	0.1240
59	Union Parkway Belt	St. Clair	8.78494	0.2888	0.51222	0.0168
60	Union Parkway Belt	Welwyn	50.36574	1.6559	4.33164	0.1424
61	Union Parkway Belt	Dawn Export	8.28428	0.2724	0.46629	0.0153
62	Union SSMDA	Empress	-	1.2649	-	0.1386
63	Union SSMDA	TransGas SSDA	-	1.0300	-	0.1111
64	Union SSMDA	Centram SSDA	-	0.9338	-	0.0998
65	Union SSMDA	Centram MDA	-	0.7882	-	0.0827
66	Union SSMDA	Centrat MDA	-	0.7876	-	0.0827
67	Union SSMDA	Union WDA	-	1.0598	-	0.1146
68	Union SSMDA	Nipigon WDA	-	1.1416	-	0.1241
69	Union SSMDA	Union NDA	-	0.8315	-	0.0878
70	Union SSMDA	Calstock NDA	-	1.0598	-	0.1146
71	Union SSMDA	Tunis NDA	-	0.9188	-	0.0980
72	Union SSMDA	GMIT NDA	-	0.8140	-	0.0857
73	Union SSMDA	Union SSMDA	-	0.0905	-	0.0009
74	Union SSMDA	Union NCDA	-	0.6757	-	0.0656
75	Union SSMDA	Union CDA	-	0.5678	-	0.0536
76	Union SSMDA	Union ECDA	-	0.5774	-	0.0547
77	Union SSMDA	Union EDA	-	0.7545	-	0.0744
78	Union SSMDA	Union Parkway Belt	-	0.5709	-	0.0540
79	Union SSMDA	Enbridge CDA	-	0.6123	-	0.0586
80	Union SSMDA	Enbridge Parkway CDA	-	0.5709	-	0.0540
81	Union SSMDA	Enbridge EDA	-	0.8328	-	0.0832

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Effective
2018-04-01
Rate M12
Page 1 of 4

TRANSPORTATION RATES

(A) Applicability

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

Applicable Points
Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).
Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Parkway 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 Charges (applied to daily contract demand) Rate/GJ	Fuel and Commodity Charges: Union Supplied Fuel – Fuel and Commodity Charge Rate/GJ	Shipper Supplied Fuel – Fuel Ratio %	AND	Shipper Supplied Fuel – Commodity Charge Rate/GJ
Firm Transportation (1), (5)					
Dawn to Parkway	$3.716	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$3.154				
Kirkwall to Parkway	$0.561				
M12-X Firm Transportation					
Between Dawn, Kirkwall and Parkway	$4.590	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)					
Dawn to Parkway – Maximum	$8.918	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$8.918				
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.158%		
Cap-and-Trade Facility-Related Charges (applied to all quantities transported)					
Dawn to Kirkwall / Lisgar		$0.006			$0.006
Dawn to Parkway		$0.006			$0.006
Kirkwall to Parkway / Lisgar		$0.006			$0.006
Parkway to Dawn / Kirkwall		$0.006			$0.006
Kirkwall to Dawn		$0.006			$0.006
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)		$0.006			$0.006

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln									
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	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 64 * ln 104	[redacted]						
13	Niagara Supply	ln 65 * ln 109							
14	TGP Supply (Direct)	ln 66 * ln 125							
15	Dracut Supply 1 - Baseload	ln 67 * ln 114							
16	Dracut Supply 2 - Swing	ln 68 * ln 119							
17	ENG E COMBO	ln 69 * ln 131							
18	LNG Truck	ln 70 * ln 133							
19	Propane Truck	ln 71 * ln 135							
20	PNGTS	ln 72 * ln 140							
21	Portland Natural Gas	ln 73 * ln 145							
22	TGP Supply (Z4)	ln 74 * ln 150							
23									
24	Subtotal Pipeline Gas Costs		$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499	$ 42,563,780
25									
26	**Volumetric Transportation Costs**								
27	Dawn Supply	ln 64 * ln 197	[redacted]						
28	Niagara Supply	ln 65 * ln 208							
29	TGP Supply (Direct)	ln 66 * ln 235							
30	Dracut Supply 1 - Baseload	ln 67 * ln 256							
31	Dracut Supply 2 - Swing	ln 68 * ln 256							
32	ENG E COMBO	ln 69 * ln 256							
33	TGP Storage - Withdrawals	ln 79 * ln 172							
34									
35	**Total Volumetric Transportation Costs**		$ 215,648	$ 213,629	$ 237,663	$ 219,674	$ 201,319	$ 38,974	$ 1,126,907
36									
37	**Less - Gas Refill**								
38	LNG Truck	ln 88 * ln 157	[redacted]						
39	Propane	ln 89 * ln 158							
40	TGP Storage Refill	ln 90 * ln 123							
41	Storage Refill (Trans.)	ln 90 * ln 235							
42									
43	Subtotal Refills		$ (765,580)	$ (131,625)	$ (809,867)	$ (600,010)	$ (65,260)	$ -	$ (2,372,341)
44									
45	**Total Supply & Pipeline Commodity Costs**	ln 24 + ln 35 + ln 43	$ 2,553,342	$ 8,898,538	$ 11,299,833	$ 10,827,598	$ 5,600,561	$ 2,138,473	$ 41,318,346
46									
47	**Storage Gas**								
48	TGP Storage - Withdrawals	ln 79 * ln 164	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894	$ 5,125,663
49									
50	**Produced Gas**								
51	LNG Vapor	ln 82 * ln 152	[redacted]						
52	Propane	ln 83 * ln 154							
53									
54	**Total Produced Gas**	ln 51 + ln 52	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567	$ 2,672,211
55									
56									
57	**Total Commodity Gas & Trans. Costs**	ln 45 + ln 48 + ln 54	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935	$ 49,116,221
58									$ 87,958,623
59						**REDACTED**			

Line									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
60									
61	**Volumes (Therms)**								
62									
63	**Pipeline Gas**	See Schedule 11A							
64	Dawn Supply		796,342	878,932	897,468	806,735	883,624	543,941	4,807,042
65	Niagara Supply		625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
66	TGP Supply (Direct)		4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382	16,183,681
67	Dracut Supply 1 - Baseload		-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
68	Dracut Supply 2 - Swing		2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232	11,732,071
69	ENG E COMBO		-	945,993	1,229,648	1,264,827	734,441	-	4,174,908
70	LNG Truck		18,690	289,648	685,485	1,029,982	145,597	-	2,169,402
71	Propane Truck		-	-	356,219	91,328	-	-	447,548
72	PNGTS		198,251	197,617	108,541	146,415	191,500	201,686	1,044,010
73	Portland Natural Gas		345,771	381,679	389,728	350,092	383,716	260,087	2,111,074
74	TGP Supply (Z4)		1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079	12,999,054
75									
76	Subtotal Pipeline Volumes		10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703	69,847,042
77									
78	**Storage Gas**								
79	TGP Storage		1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558	19,841,326
80									
81	**Produced Gas**								
82	LNG Vapor		18,690	289,648	777,271	1,029,982	64,550	19,014	2,199,156
83	Propane		-	-	859,588	91,328	-	-	950,916
84									
85	Subtotal Produced Gas		18,690	289,648	1,636,859	1,121,310	64,550	19,014	3,150,073
86									
87	**Less - Gas Refill**								
88	LNG Truck		(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-	(2,169,402)
89	Propane		-	-	(356,219)	(91,328)	-	-	(447,548)
90	TGP Storage Refill		(2,262,867)	-	-	-	-	-	(2,262,867)
91									
92	Subtotal Refills		(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-	(4,879,817)
93									
94	**Total Sendout Volumes**		9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276	87,958,623
95									
96									
97									

REDACTED

Line		Reference							Peak
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
98	**Gas Costs and Volumetric Transportation Rates**								
99									
100	**Pipeline Gas**								
101	**Dawn Supply**								Average Rate
102	NYMEX Price	Sch 7, ln 10/10	[redacted]						
103	Basis Differential								
104	**Net Commodity Costs**								
105									
106	**Niagara Supply**								
107	NYMEX Price	Sch 7, ln 10/10	[redacted]						
108	Basis Differential								
109	**Net Commodity Costs**								
110									
111	**Dracut Supply 1 - Baseload**								
112	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
113	Basis Differential								
114	**Net Commodity Costs**								
115									
116	**Dracut Supply 2 - Swing**								
117	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
118	Basis Differential								
119	**Net Commodity Costs**								
120									
121									
122	**TGP Supply (Direct)**								
123	NYMEX Price	Sch 7, ln 10/10	[redacted]						
124	Basis Differential								
125	**Net Commodity Costs**								
126									
127									
128	**ENGIE COMBO**								
129	NYMEX Price	Sch 7, ln 10/10	[redacted]						
130	Basis Differential								
131	**Net Commodity Costs**								
132									
133	**LNG Truck**	Sch 7, ln 10/10	[redacted]						
134									
135	**Propane Truck**	Propane WACOG	[redacted]						
136									
137	**PNGTS**								
138	NYMEX Price	Sch 7, ln 10/10	[redacted]						
139	Basis Differential								
140	**Net Commodity Cost**								
141									
142	**PNGTS EXP**								
143	NYMEX Price	Sch 7, ln 10/10	[redacted]						
144	Basis Differential								
145	**Net Commodity Cost**								
146									
147	**TGP Supply (Z4)**								
148	NYMEX Price	Sch 7, ln 10/10	[redacted]						
149	Basis Differential								
150	**Net Commodity Cost**								
151									
152	**LNG Vapor (Storage)**	Sch 16, ln 95 /10	[redacted]						
153									
154	**Propane**	Sch 16, ln 66 /10	[redacted]						
155									
156	**Storage Refill**								
157	**LNG Truck**	ln 133	[redacted]						
158	**Propane**	ln 135							
159									

REDACTED

060

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
160									
161									
162	**TGP Storage**								Average Rate
163	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.2583	$0 2583	$0 2583	$0.2583	$0.2583	$0.2583	$0.2583
164									
165	TGP - Max Commodity - Z 4-6	13th Rev Sheet No. 15	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050
166	TGP - Max Comm. ACA Rate - Z 4-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
167	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.01063	$0.01063	$0.01063	$0.01063	$0.01063	$0.01063	$0.01063
168	TGP - Fuel Charge % - Z 4-6	13th Rev Sheet No. 32	1.24%	1.24%	1.24%	1 24%	1.24%	1 24%	1.24%
169	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00320	$0.00320	$0.00320	$0.00320	$0.00320	$0.00320	$0.00320
170	TGP - Withdrawal Charge	14th Rev Sheet No.61	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087
171	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.01470	$0.01470	$0.01470	$0.01470	$0.01470	$0.01470	$0.01470
172									
173	**Total TGP - Comm. & Vol. Trans. Rate**	ln 164 + ln 172	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**
174									
175									
176	**Per Unit Volumetric Transportation Rates**								
177	**Dawn Supply Volumetric Transportation Charge**								
178	**Commodity Costs**	ln 104	**$0.2977**	**$0.3162**	**$0.3306**	**$0.3269**	**$0.3056**	**$0.2519**	**$0.3048**
179									
180	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00060	$0.00060	$0.00060	$0.00060	$0.00060	$0.00060	$0.00060
181	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
182	Conversion Rate to US$	updated 7/6/18	1 2851	1 2851	1 2851	1.2851	1.2851	1.2851	1.2851
183	Commodity Rate/US$	ln 181 x ln 182 x ln 183	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081
184	TransCanada Fuel %	Union Parkway to Iroquois	1.95%	2.01%	2.20%	2.17%	1.78%	2 20%	2.05%
185	TransCanada Fuel * Percentage	ln 179 x ln 185	$0.00581	$0.00634	$0.00726	$0.00708	$0.00545	$0.00553	$0.00625
186	Subtotal TransCanada		**$0.00663**	**$0.00715**	**$0.00808**	**$0.00790**	**$0.00626**	**$0.00635**	**$0.00706**
187	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
188	IGTS - Z1 RTS ACA Rate Commodity	Fifth Revised Sheet 4A	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
189	IGTS - Z1 RTS Deferred Asset Surcharge	Fifth Revised Sheet 4A	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
190	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**
191	TGP NET-NE - Comm. Segments 3 & 4	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
192	IGTS -Fuel Use Factor - Percentage	Fifth Revised Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
193	IGTS -Fuel Use Factor - Fuel * Percentage	ln 179 x ln 193	**$0.00298**	**$0.00316**	**$0.00331**	**$0.00327**	**$0.00306**	**$0.00252**	**$0.00305**
194	TGP FTA Fuel Charge % Z 5-6	13th Rev Sheet No. 32	0.91%	0.91%	0.91%	0 91%	0.91%	0 91%	0.91%
195	TGP FTA Fuel * Percentage	ln 179 x ln 195	**$0.00271**	**$0.00288**	**$0.00301**	**$0.00297**	**$0.00278**	**$0.00229**	**$0.00277**
196	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01291**	**$0.01379**	**$0.01499**	**$0.01474**	**$0.01270**	**$0.01176**	**$0.01348**
197									
198									
199	**Niagara Supply Volumetric Transportation Charge**								
200	**Commodity Costs**	Ln 109	[redacted]						
201									
202	TGP FTA - FTA Z 5-6 Comm. Rate	13th Rev Sheet No. 15	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796
203	TGP FTA - FTA Z 5-6 - ACA Rate	13th Rev Sheet No. 15	$0.00013	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
204	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00809**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**
205	TGP FTA Fuel Charge % Z 5-6	13th Rev Sheet No. 32	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%
206	TGP FTA Fuel * Percentage	ln 201 x ln 206	[redacted]						
207	**Total Volumetric Transportation Rate - Niagara Supply**								
208									
209									
210									

REDACTED

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
211									
212									
213	**TGP Direct Volumetric Transportation Charge**								Average Rate
214	**Commodity Costs**	Ln 123	[redacted]						
215									
216	TGP - Max Comm. Base Rate - Z 0-6	13th Rev Sheet No. 15	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039
217	TGP - Max Commodity ACA Rate - Z 0-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
218	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052
219	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
220	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**
221	TGP - Max Comm. Base Rate - Z 1-6	13th Rev Sheet No. 15	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650
222	TGP - Max Commodity ACA Rate - Z 1-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
223	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663
224	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**
226	TGP - Fuel Charge % - Z 0 -6	13th Rev Sheet No. 32	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%
227	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
228	Prorated TGP Fuel Charge % - Z 0-6		1.45%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%
229	TGP - Fuel Charge % - Z 1 -6	13th Rev Sheet No. 32	3.88%	3.88%	3.88%	3 88%	3.88%	3.88%	3.88%
230	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
231	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
232	TGP - Fuel Charge % - Z 0-6	ln 215 x ln 229	**$0.00427**	**$0.00440**	**$0.00453**	**$0.00447**	**$0.00432**	**$0.00387**	**$0.00431**
233	TGP - Fuel Charge % - Z 1-6	ln 215 x ln 232	**$0.00771**	**$0.00796**	**$0.00818**	**$0.00808**	**$0.00781**	**$0.00699**	**$0.00779**
234	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03987**	**$0.04026**	**$0.04060**	**$0.04045**	**$0.04003**	**$0.03876**	**$0.04000**
235									
236	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
237	**Commodity Costs**	Ln 123	[redacted]						
238									
239	TGP - Max Comm. Base Rate - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
240	TGP - Max Commodity ACA Rate - Z 6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
241	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
242	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
243	TGP - Fuel Charge	ln 238 x ln 243	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**
244	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**
245									
246									
247	**TGP Dracut**								
248	**Commodity Costs - NYMEX Price**	Ln 114	[redacted]						
249									
250	TGP - Trans Charge - Comm. - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
251	TGP - Trans Charge - ACA Rate - Z6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
252	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
253	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
254	TGP - Fuel Charge	ln 249 x ln 254	[redacted]						
255	**Total Volumetric Transportation Rate - TGP Dracut**								
256									
257						**REDACTED**			

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
NYMEX Futures @ Henry Hub

For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Strip Average
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
I. NYMEX Opening Prices as of									
Opening Prices (15 day average)			2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$ 2.9782
NYMEX		**Filed COG**	2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$ 2.9782

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
NYMEX Futures @ Henry Hub

For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Strip Average
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
NYMEX Settlement - 15 Day Average									
	Days	Date							
	1	21-Aug	2 9910	3.0830	3.1670	3.1310	3.0270	2.7090	
	2	20-Aug	2 9660	3.0610	3.1450	3.1090	3.0060	2.7010	
	3	17-Aug	2 9860	3.0820	3.1680	3.1320	3.0280	2.7080	
	4	16-Aug	2 9500	3.0460	3.1340	3.1000	2.9980	2.6930	
	5	15-Aug	2 9850	3.0780	3.1650	3.1280	3.0220	2.7060	
	6	14-Aug	3.0020	3.0920	3.1760	3.1380	3.0320	2.7130	
	7	13-Aug	2 9710	3.0590	3.1450	3.1090	3.0040	2.6980	
	8	10-Aug	2 9820	3.0670	3.1510	3.1130	3.0080	2.6910	
	9	9-Aug	2 9920	3.0770	3.1620	3.1250	3.0220	2.6980	
	10	8-Aug	2 9890	3.0770	3.1630	3.1240	3.0190	2.6910	
	11	7-Aug	2 9350	3.0310	3.1170	3.0800	2.9740	2.6570	
	12	6-Aug	2 9030	3.0030	3.0900	3.0520	2.9470	2.6340	
	13	3-Aug	2 8980	2.9980	3.0820	3.0450	2.9410	2.6260	
	14	2-Aug	2 8570	2.9580	3.0430	3.0060	2.9030	2.6050	
	15	1-Aug	2 8110	2.9190	3.0050	2.9710	2.8680	2 5820	
		15 Day Average	2 9479	3.0421	3.1275	3.0909	2.9866	2.6741	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 17 - Apr 18 vs Nov 18 - Apr 19 - Residential Heating Rate R-3

November 1, 2018 - April 30, 2019
Residential Heating (R3)

PROPOSED			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**
average Usage (Therms)			38	95	157	139	107	100	636
	5/1/2018	7/1/2018							
Winter:									
Cust. Chg	$24.43	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12
Headblock	$0.3863	$0.5631	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.3197	$0.5631	$21.33	$53.70	$88.19	$78.12	$60.12	$56.40	$357.86
HB Threshold	100	-							
Summer:									
Cust. Chg	$14.88	$15.02							
Headblock	$0.5580	$0.5631							
Tailblock	$0.5580	$0.5631							
HB Threshold	-	-							
Total Base Rate Amount			$36.35	$68.72	$103.21	$93.14	$75.14	$71.42	$447.98
COG Rate - (Seasonal)			$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411
COG amount			$28.07	$70.68	$116.07	$102.82	$79.12	$74.23	$470.98
LDAC			$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836
LDAC amount			$3.17	$7.98	$13.10	$11.60	$8.93	$8.38	$53.15
Total Bill			**$67.58**	**$147.37**	**$232.37**	**$207.57**	**$163.19**	**$154.03**	**$972.12**

May 1, 2018 - October 31, 2018

	May-18	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)	56	21	17	15	16	18	142	778
Summer:								
Cust. Chg	$14.88	$14.88	$15.02	$15.02	$15.02	$15.02	$89.84	$179.96
Headblock	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$30.99	$11.84	$9.43	$8.47	$8.80	$10.15	$79.67	$437.53
Total Base Rate Amount	$45.87	$26.72	$24.45	$23.49	$23.82	$25.17	$169.51	$617.49
COG Rate - (Seasonal)	$0.3133	$0.3916	$0.3127	$0.3665	$0.3916	$0.3916	$0.3491	$0.6694
COG amount	$17.40	$8.31	$5.24	$5.51	$6.12	$7.06	$49.63	$520.62
LDAC	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0856
LDAC amount	$5.25	$2.00	$1.58	$1.42	$1.48	$1.70	$13.44	$66.59
Total Bill	**$68.51**	**$37.03**	**$31.27**	**$30.42**	**$31.42**	**$33.93**	**$232.58**	**$1,204.70**

November 1, 2017 - April 30, 2018
Residential Heating (R3)

CURRENT			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**
average Usage (Therms)			38	95	157	139	107	100	636
Winter:	5/1/2017	7/1/2017							
Cust. Chg	$22.10	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58
Headblock	$0.3495	$0.3863	$14.63	$36.84	$38.63	$38.63	$38.63	$38.63	$205.99
Tailblock	$0.2892	$0.3197	$0.00	$0.00	$18.10	$12.39	$2.16	$0.05	$32.70
HB Threshold	100	100							
Summer:									
Cust. Chg	$22.10	$24.43							
Headblock	$0.3495	$0.3863							
Tailblock	$0.2892	$0.3197							
HB Threshold	20	20							
Total Base Rate Amount			$39.06	$61.27	$81.16	$75.45	$65.22	$63.11	$385.27
COG Rate - (Seasonal)			$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7321
COG amount			$24.41	$61.46	$100.94	$111.77	$86.01	$80.69	$465.28
LDAC			$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856
LDAC amount			$3.24	$8.16	$13.41	$11.88	$9.14	$8.57	$54.40
Total Bill			**$66.71**	**$130.90**	**$195.50**	**$199.09**	**$160.37**	**$152.38**	**$904.95**
DIFFERENCE:									
Total Bill			**$0.87**	**$16.48**	**$36.87**	**$8.48**	**$2.82**	**$1.65**	**$67.17**
% Change			**1.30%**	**12.59%**	**18.86%**	**4.26%**	**1.76%**	**1.08%**	**7.42%**
Base Rate			($2.71)	$7.45	$22.05	$17.70	$9.92	$8.31	$62.71
% Change			-6.95%	12.16%	27.17%	23.46%	15.20%	13.17%	16.28%
COG & LDAC			$3.58	$9.03	$14.82	($9.22)	($7.10)	($6.66)	$4.46
% Change			14.68%	14.68%	14.68%	-8.25%	-8.25%	-8.25%	0.96%
check			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

May 1, 2017 - October 31, 2017

	May-17	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)	56	21	17	15	16	18	142	778
Summer:								
Cust. Chg	$22.10	$22.10	$24.43	$24.43	$24.43	$24.43	$141.92	$288.50
Headblock	$6.99	$6.99	$6.47	$5.81	$6.04	$6.96	$39.26	$245.25
Tailblock	$10.27	$0.35	$0.00	$0.00	$0.00	$0.00	$10.63	$43.32
Total Base Rate Amount	$39.36	$29.44	$30.90	$30.24	$30.47	$31.39	$191.81	$577.08
COG Rate - (Seasonal)	$0.4368	$0.4368	$0.4368	$0.4725	$0.4725	$0.4725	$0.4490	$0.6804
COG amount	$24.26	$9.27	$7.31	$7.11	$7.39	$8.52	$63.84	$529.12
LDAC	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0817
LDAC amount	$3.55	$1.36	$1.07	$0.96	$1.00	$1.15	$9.10	$63.50
Total Bill	**$67.17**	**$40.07**	**$39.28**	**$38.31**	**$38.85**	**$41.07**	**$264.75**	**$1,169.70**
DIFFERENCE:								
Total Bill	**$1.34**	**($3.04)**	**($8.02)**	**($7.89)**	**($7.43)**	**($7.13)**	**($32.17)**	**$35.00**
% Change	**1.99%**	**-7.58%**	**-20.41%**	**-20.59%**	**-19.13%**	**-17.37%**	**-12.15%**	**2.99%**
Base Rate	$6.50	($2.72)	($6.45)	($6.75)	($6.65)	($6.22)	($22.29)	$40.42
% Change	16.51%	-9.25%	-20.87%	-22.33%	-21.81%	-19.82%	-11.62%	7.00%
COG & LDAC	($5.16)	($0.31)	($1.57)	($1.14)	($0.79)	($0.91)	($9.88)	($5.42)
% Change	-21.29%	-3.37%	-21.43%	-15.98%	-10.67%	-10.67%	-15.47%	-1.02%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-41

November 1, 2018 - April 30, 2019 / **May 1, 2018 - October 31, 2018**
Commercial Rate (G-41)

PROPOSED			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			89	277	504	457	331	297	1,954	153	39	26	34	25	29	306	2,260
Winter:	7/1/2018	5/1/2018															
Cust. Chg	$56.58	$53.45	$56.58	$56.58	$56.58	$56.58	$56.58	$56.58	$339.48								
Headblock	$0.4639	$0.4383	$41.15	$46.39	$46.39	$46.39	$46.39	$46.39	$273.10								
Tailblock	$0.3116	$0.2944	$0.00	$55.19	$125.84	$111.12	$71.93	$61.33	$425.41								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$56.58	$56.07								$56.07	$56.07	$56.58	$56.58	$56.58	$56.58	$338.47	$677.95
Headblock	$0.4639	$0.4597								$9.19	$9.19	$9.28	$9.28	$9.28	$9.28	$55.50	$328.60
Tailblock	$0.3116	$0.3088								$40.99	$5.78	$1.96	$4.23	$1.58	$2.87	$57.41	$482.82
HB Threshold	20	20															
Total Base Rate Amount			$97.73	$158.16	$228.81	$214.09	$174.90	$164.30	$1,037.99	$106.25	$71.05	$67.82	$70.09	$67.44	$68.73	$451.38	$1,489.37
COG Rate - (Seasonal)			$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.3084	$0.3855	$0.3066	$0.3604	$0.3855	$0.3855	$0.3374	$0.6858
COG amount			$65.67	$205.16	$373.01	$338.04	$244.91	$219.74	$1,446.51	$47.11	$14.93	$8.06	$12.10	$9.66	$11.26	$103.11	$1,549.63
LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0770
LDAC amount			$6.84	$21.38	$38.88	$35.23	$25.53	$22.90	$150.76	$11.65	$2.95	$2.00	$2.56	$1.91	$2.23	$23.32	$174.08
Total Bill			**$170.24**	**$384.70**	**$640.69**	**$587.36**	**$445.33**	**$406.94**	**$2,635.27**	**$165.01**	**$88.93**	**$77.88**	**$84.75**	**$79.02**	**$82.22**	**$577.81**	**$3,213.08**

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Commercial Rate (G-41)

CURRENT			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			89	277	504	457	331	297	1,954	153	39	26	34	25	29	306	2,260
Winter:	7/1/2017	5/1/2017															
Cust. Chg	$53.45	$48.36	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70								
Headblock	$0.4383	$0.3965	$38.88	$43.83	$43.83	$43.83	$43.83	$43.83	$258.03								
Tailblock	$0.2944	$0.2663	$5.45	$52.15	$118.90	$104.99	$67.96	$57.94	$407.38								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$53.45	$48.36								$48.36	$48.36	$53.45	$53.45	$53.45	$53.45	$310.52	$631.22
Headblock	$0.4383	$0.3965								$7.93	$7.93	$8.77	$8.77	$8.77	$8.77	$50.94	$308.97
Tailblock	$0.2944	$0.2663								$27.20	$7.84	$2.20	$1.08	$0.86	$6.66	$45.84	$453.22
HB Threshold	20	20															
Total Base Rate Amount			$97.78	$149.43	$216.18	$202.27	$165.24	$155.22	$986.11	$83.49	$64.13	$64.42	$63.30	$63.08	$68.88	$407.30	$1,393.41
COG Rate - (Seasonal)			$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7325	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4309	$0.6917
COG amount			$57.06	$178.28	$324.13	$367.17	$266.02	$238.67	$1,431.33	$64.24	$16.29	$11.05	$15.32	$11.44	$13.33	$131.67	$1,563.00
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0644
LDAC amount			$5.98	$18.68	$33.96	$30.78	$22.30	$20.01	$131.70	$6.87	$1.74	$1.18	$1.51	$1.13	$1.31	$13.75	$145.45
Total Bill			**$160.82**	**$346.38**	**$574.27**	**$600.21**	**$453.55**	**$413.90**	**$2,549.14**	**$154.61**	**$82.16**	**$76.65**	**$80.13**	**$75.65**	**$83.52**	**$552.72**	**$3,101.86**

DIFFERENCE:

Total Bill	**$9.42**	**$38.32**	**$66.43**	**($12.85)**	**($8.22)**	**($6.97)**	**$86.13**	**$10.41**	**$6.77**	**$1.22**	**$4.62**	**$3.37**	**($1.30)**	**$25.09**	**$111.22**
% Change	**5.86%**	**11.06%**	**11.57%**	**-2.14%**	**-1.81%**	**-1.68%**	**3.38%**	**6.73%**	**8.24%**	**1.60%**	**5.77%**	**4.46%**	**-1.56%**	**4.54%**	**3.59%**
Base Rate	($0.05)	$8.74	$12.64	$11.82	$9.66	$9.08	$51.88	$22.76	$6.92	$3.40	$6.79	$4.36	($0.15)	$44.08	$95.97
% Change	-0.05%	5.85%	5.85%	5.85%	5.85%	5.85%	5.26%	27.27%	10.79%	5.27%	10.73%	6.91%	-0.21%	10.82%	6.89%
COG & LDAC	$9.47	$29.59	$53.79	($24.68)	($17.88)	($16.04)	$34.25	($12.36)	($0.15)	($2.17)	($2.17)	($0.99)	($1.15)	($18.99)	$15.26
% Change	16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.39%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-14.42%	0.98%
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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 **d/b/a Liberty Utilities**
2 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-42**
5
6
7 **November 1, 2018 - April 30, 2019** | **May 1, 2018 - October 31, 2018**
8 **C&I High Winter Use Medium G-42**

Line										Winter							Summer	Total
9	**PROPOSED**																	
10				**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**May-Oct**	**Nov-Oct**
11	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
12		7/1/2018	5/1/2018															
13	**Winter:**																	
14	Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50								
15	Headblock	$0.4219	$0.3986	$350.20	$421.90	$421.90	$421.90	$421.90	$421.90	$2,459.70								
16	Tailblock	$0.2811	$0.2655	$0.00	$334.13	$761.08	$676.27	$450.55	$392.11	$2,614.13								
17	HB Threshold	1,000	1,000															
18																		
19	**Summer:**																	
20	Cust. Chg	$169.75	$168.21								$160.36	$160.36	$169.75	$169.75	$169.75	$169.75	$999.72	$2,018.22
21	Headblock	$0.4219	$0.4181								$167.24	$167.24	$120.07	$104.03	$113.31	$143.61	$815.50	$3,275.21
22	Tailblock	$0.2811	$0.2785								$255.94	$23.42	$0.00	$0.00	$0.00	$0.00	$279.36	$2,893.49
23	HB Threshold	400	400															
24																		
25	Total Base Rate Amount			$519.95	$925.78	$1,352.73	$1,267.92	$1,042.20	$983.76	$6,092.33	$583.54	$351.02	$289.82	$273.78	$283.06	$313.36	$2,094.59	$8,186.92
26																		
27	COG Rate - (Seasonal)			$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.3084	$0.3855	$0.3066	$0.3604	$0.3855	$0.3855	$0.3412	$0.6753
28	COG amount			$614.49	$1,620.25	$2,744.67	$2,521.30	$1,926.86	$1,772.94	$11,200.51	$406.78	$186.62	$87.26	$88.87	$103.54	$131.22	$1,004.28	$12,204.79
29																		
30	LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0770
31	LDAC amount			$64.04	$168.87	$286.06	$262.78	$200.82	$184.78	$1,167.36	$100.64	$36.94	$21.71	$18.81	$20.49	$25.97	$224.57	$1,391.93
32																		
33	**Total Bill**			**$1,198.49**	**$2,714.89**	**$4,383.46**	**$4,052.00**	**$3,169.88**	**$2,941.48**	**$18,460.21**	**$1,090.97**	**$574.57**	**$398.79**	**$381.46**	**$407.09**	**$470.55**	**$3,323.43**	**$21,783.64**

34
35 **November 1, 2017 - April 30, 2018** | **May 1, 2017 - October 31, 2017**
36 **C&I High Winter Use Medium G-42**

Line										Winter							Summer	Total
37	**CURRENT**																	
38				**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**May-Oct**	**Nov-Oct**
39	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
40		5/1/2017	7/1/2017															
41	**Winter:**																	
42	Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
43	Headblock	$0.3606	$0.3986	$330.86	$398.60	$398.60	$398.60	$398.60	$398.60	$2,323.86								
44	Tailblock	$0.2402	$0.2655	$0.00	$315.58	$718.84	$638.74	$425.54	$370.34	$2,469.05								
45	HB Threshold	1,000	1,000															
46																		
47	**Summer:**																	
48	Cust. Chg	$145.08	$160.36								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
49	Headblock	$0.3606	$0.3986								$144.24	$144.24	$113.44	$98.29	$107.06	$135.68	$742.94	$3,066.80
50	Tailblock	$0.2402	$0.2655								$220.75	$28.09	$0.00	$0.00	$0.00	$0.00	$248.84	$2,717.89
51	HB Threshold	400	400															
52																		
53	Total Base Rate Amount			$491.22	$874.54	$1,277.80	$1,197.70	$984.50	$929.30	$5,755.08	$510.07	$317.41	$273.80	$258.65	$267.42	$296.04	$1,923.37	$7,678.45
54																		
55	COG Rate - (Seasonal)			$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7326	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4310	$0.6835
56	COG amount			$533.98	$1,407.95	$2,385.04	$2,738.59	$2,092.92	$1,925.74	$11,084.22	$554.78	$203.61	$119.70	$112.51	$122.55	$155.32	$1,268.47	$12,352.68
57																		
58	LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0638
59	LDAC amount			$55.95	$147.51	$249.89	$229.55	$175.43	$161.42	$1,019.74	$59.36	$21.78	$12.81	$11.10	$12.09	$15.32	$132.45	$1,152.19
60																		
61	**Total Bill**			**$1,081.15**	**$2,430.01**	**$3,912.73**	**$4,165.84**	**$3,252.85**	**$3,016.46**	**$17,859.03**	**$1,124.20**	**$542.80**	**$406.30**	**$382.26**	**$402.05**	**$466.67**	**$3,324.29**	**$21,183.32**

62
63 **DIFFERENCE:**

Line																		
64	**Total Bill**			**$117.35**	**$284.88**	**$470.73**	**($113.84)**	**($82.97)**	**($74.98)**	**$601.17**	**($33.23)**	**$31.77**	**($7.51)**	**($0.79)**	**$5.04**	**$3.88**	**($0.85)**	**$600.32**
65	% Change			**10.85%**	**11.72%**	**12.03%**	**-2.73%**	**-2.55%**	**-2.49%**	**3.37%**	**-2.96%**	**5.85%**	**-1.85%**	**-0.21%**	**1.25%**	**0.83%**	**-0.03%**	**2.83%**
66																		
67	**Base Rate**			$28.73	$51.23	$74.93	$70.22	$57.69	$54.45	$337.25	$73.48	$33.61	$16.02	$15.14	$15.65	$17.32	$171.21	$508.47
68	% Change			5.85%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	14.41%	10.59%	5.85%	5.85%	5.85%	5.85%	8.90%	6.62%
69																		
70	**COG & LDAC**			$88.61	$233.65	$395.80	($184.06)	($140.66)	($129.43)	$263.92	($106.71)	($1.84)	($23.54)	($15.93)	($10.61)	($13.45)	($172.07)	$91.85
71	% Change			16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.38%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-13.56%	0.74%
	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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-52

November 1, 2018 - April 30, 2019 / **May 1, 2018 - October 31, 2018**
Commercial Rate (G-52)

PROPOSED			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,306	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
Winter:	7/1/2018	5/1/2018															
Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50								
Headblock	$0.2401	$0.2268	$240.10	$240.10	$240.10	$240.10	$240.10	$240.10	$1,440.60								
Tailblock	$0.1600	$0.1511	$56.28	$138.55	$205.37	$185.54	$141.69	$121.61	$849.04								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$169.75	$168.21								$168.21	$168.21	$169.75	$169.75	$169.75	$169.75	$1,015.42	$2,033.92
Headblock	$0.1740	$0.1724								$172.40	$172.40	$174.00	$174.00	$174.00	$156.04	$1,022.84	$2,463.44
Tailblock	$0.0989	$0.0980								$49.15	$12.63	$3.16	$2.48	$4.92	$0.00	$72.35	$921.38
HB Threshold	1,000	1,000															
Total Base Rate Amount			$466.13	$548.40	$615.22	$595.39	$551.54	$531.46	$3,308.14	$389.76	$353.24	$346.91	$346.23	$348.67	$325.79	$2,110.61	$5,418.74
COG Rate - (Seasonal)			$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.3299	$0.4124	$0.3335	$0.3873	$0.4124	$0.4124	$0.3776	$0.6096
COG amount			$1,007.86	$1,391.23	$1,702.65	$1,610.22	$1,405.86	$1,312.30	$8,430.11	$493.86	$465.08	$344.16	$397.00	$432.94	$369.83	$2,502.87	$10,932.98
LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0768
LDAC amount			$104.30	$143.97	$176.19	$166.63	$145.48	$135.80	$872.37	$114.22	$86.05	$78.74	$78.21	$80.10	$68.42	$505.74	$1,378.11
Total Bill			**$1,578.29**	**$2,083.59**	**$2,494.07**	**$2,372.23**	**$2,102.88**	**$1,979.56**	**$12,610.61**	**$997.85**	**$904.37**	**$769.80**	**$821.44**	**$861.71**	**$764.05**	**$5,119.22**	**$17,729.83**

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Commercial Rate (G-52)

CURRENT			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,306	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
Winter:	5/1/2017	7/1/2017															
Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
Headblock	$0.2052	$0.2268	$226.80	$226.80	$226.80	$226.80	$226.80	$226.80	$1,360.80								
Tailblock	$0.1367	$0.1511	$53.15	$130.84	$193.95	$175.22	$133.81	$114.84	$801.81								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$145.08	$160.36								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
Headblock	$0.1487	$0.1644								$148.70	$148.70	$164.40	$164.40	$164.40	$147.43	$938.03	$2,298.83
Tailblock	$0.0845	$0.0934								$32.97	$7.82	$2.98	$2.34	$4.65	$0.00	$50.76	$852.57
HB Threshold	1,000	1,000															
Total Base Rate Amount			$440.31	$518.00	$581.11	$562.38	$520.97	$502.00	$3,124.77	$326.75	$301.60	$327.74	$327.10	$329.41	$307.79	$1,920.40	$5,045.16
COG Rate - (Seasonal)			$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7397	$0.4574	$0.4574	$0.4574	$0.4931	$0.4931	$0.4931	$0.4734	$0.6413
COG amount			$886.74	$1,224.04	$1,498.04	$1,764.63	$1,546.14	$1,443.25	$8,362.84	$684.73	$515.83	$472.01	$505.45	$517.65	$442.21	$3,137.88	$11,500.72
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0591
LDAC amount			$91.11	$125.76	$153.91	$145.56	$127.09	$118.63	$762.06	$67.37	$50.75	$46.44	$46.13	$47.24	$40.36	$298.27	$1,060.33
Total Bill			**$1,418.16**	**$1,867.80**	**$2,233.06**	**$2,472.57**	**$2,194.19**	**$2,063.88**	**$12,249.67**	**$1,078.85**	**$868.18**	**$846.20**	**$878.68**	**$894.31**	**$790.35**	**$5,356.55**	**$17,606.22**

DIFFERENCE:

Total Bill	**$160.13**	**$215.79**	**$261.00**	**($100.33)**	**($91.32)**	**($84.32)**	**$360.95**	**($81.00)**	**$36.19**	**($76.39)**	**($57.24)**	**($32.60)**	**($26.30)**	**($237.34)**	**$123.61**
% Change	**11.29%**	**11.55%**	**11.69%**	**-4.06%**	**-4.16%**	**-4.09%**	**2.95%**	**-7.51%**	**4.17%**	**-9.03%**	**-6.51%**	**-3.64%**	**-3.33%**	**-4.43%**	**0.70%**
Base Rate	$25.82	$30.40	$34.11	$33.01	$30.57	$29.45	$183.37	$63.01	$51.64	$19.17	$19.13	$19.26	$18.00	$190.21	$373.58
% Change	5.86%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%	19.28%	17.12%	5.85%	5.85%	5.85%	5.85%	9.90%	7.40%
COG & LDAC	$134.31	$185.39	$226.89	($133.34)	($121.89)	($113.78)	$177.58	($144.01)	($15.45)	($95.56)	($76.37)	($51.86)	($44.30)	($427.55)	($249.97)
% Change	15.15%	15.15%	15.15%	-7.56%	-7.88%	-7.88%	2.12%	-21.03%	-3.00%	-20.24%	-15.11%	-10.02%	-10.02%	-13.63%	-2.17%
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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Residential Heating

	Winter 2017-18	Winter 2018-19
Customer Charge	$24.43	$15.02
First 100 Therms	$0.3863	$0.5631
Excess 100 Therms	$0.3197	$0.5631
LDAC	$0.0856	$0.0836
COG	$0.7321	$0.7411
Total Adjust	$0.8177	$0.8247

		Winter 2017-18 COG @	Winter 2018-19 COG @	Total		Base Rate		COG		LDAC	
				$ Impact	**% Impact**	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**
		$0.8177	$0.8247	$0.01	1%						
Cooking alone	5	$30.45	$30.49	$0.04	0%	$0.00	0%	$0.04	0%	-$0.01	0%
	10	$36.47	$36.54	$0.07	0%	$0.00	0%	$0.09	0%	-$0.02	0%
	20	$48.51	$48.65	$0.14	0%	$0.00	0%	$0.18	0%	-$0.04	0%
Water Heating alone	30	$60.55	$60.76	$0.21	0%	$0.00	0%	$0.27	0%	-$0.06	0%
	45	$78.61	$78.93	$0.32	0%	$0.00	0%	$0.40	1%	-$0.09	0%
	50	$84.63	$84.98	$0.35	0%	$0.00	0%	$0.45	1%	-$0.10	0%
Heating Alone	80	$114.73	$115.26	$0.53	0%	$0.00	0%	$0.67	1%	-$0.15	0%
	125	$182.37	$183.30	$0.93	1%	$0.00	0%	$1.19	1%	-$0.26	0%
	150	$201.70	$202.76	$1.05	1%	$0.00	0%	$1.35	1%	-$0.29	0%
	200	$258.57	$259.98	$1.40	1%	$0.00	0%	$1.80	1%	-$0.39	0%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Variance Analysis of the Components of the Winter 2017-18 Actual Results vs Proposed Winter 2018-19 Cost of Gas Rate

	WINTER 2017-18 ACTUAL RESULTS (6 months actual)			**WINTER 2018-19 (6 months Proposed)**		
Therm Sales (COG)	83,403,894			86,451,254		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 8,996,827	$ 0.1079		$ 11,230,946	$ 0.1299
Purchased Gas		$ 51,743,743	0.6204	64,967,225	$ 41,318,346	0.4779
Storage/Produced Gas		$ 921,553	0.0110	22,991,399	$ 7,797,874	0.0902
Hedging (Gain)/Loss		0	0.0000		0	0.0000
Total Volumes and Cost	92,177,230	$ 61,662,124	$ 0.7393	87,958,623	$ 60,347,167	$ 0.6980
Direct Costs						
Prior Period Balance		$ 724,939	$ 0.0087		2,599,354	$ 0.0301
Interest		115,162	0.0014		63,196	0.0007
Prior Period Adjustment		-	-		351,017	0.0041
Broker Revenues		(497,759)	(0.0060)		(497,759)	(0.0058)
Refunds from Suppliers		1,054	0.0000		-	-
Fuel Financing		-	-		-	-
Transportation CGA Revenues		(59,496)	(0.0007)		(26,381)	(0.0003)
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(1,877,737)	(0.0225)		(1,877,737)	(0.0217)
Hedging Costs		-	-		-	-
FPO Admin Costs		-	-		45,000	0.0005
Indirect Costs		-	-			
Misc Overhead		10,737	0.0001		10,681	0.0001
Occupant Disallowance/Credits		-			-	-
Production & Storage		1,980,428	0.0237		1,980,428	0.0229
Bad Debt Adjustment %		227,016	0.0027		1,079,135	0.0125
Cashout, Broker penalty, Canadian Managed,…		-	-		0	0
Total Adjusted Cost		$ 62,286,467	**$ 0.7468**		$ 64,074,101	**$ 0.7412**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2018 - 2019 Winter Cost of Gas Filing
Capacity Assignment Calculations 2016-2017
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			575	578	0.4%		109	469
2	RATE R-3-Resi Htg			71,486	71,889	43.7%		4,189	67,700
3	RATE G-41 (T)			30,310	30,485	18 5%		1,045	29,440
4	RATE G-51 (S)			2,545	2,556	1 6%		670	1,886
5	RATE G-42 (V)			37,598	37,813	23 0%		1,566	36,248
6	RATE G-52			5,360	5,381	3 3%		1,846	3,535
7	RATE G-43			7,427	7,468	4 5%		587	6,881
8	RATE G-53			3,878	3,893	2.4%		1,412	2,480
9	RATE G-54			4,483	4,507	2.7%		382	4,126
10									
11	Total			163,661	164,571	100 0%		11,806	152,765
12									-
13	Residential Total			72,061	72,467	**44.034%**		4,298	68,169
14	LLF Total			75,334	75,766	**46.038%**		3,198	72,568
15	HLF Total			16,266	16,338	**9.927%**		4,310	12,027
16	Total			163,661	164,571	100 0%		11,806	152,765
17									
18	C&I Breakdown								
19	LLF Total							3,198	72,568
20	HLF Total							4,310	12,027
21	Total							7,508	84,595
22									
23	C&I Breakdown Percentage								
24	LLF Total							42.590%	85.783%
25	HLF Total							57.410%	14.217%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$12,671,205	79,718	$13 2459			
30	Storage			$4,394,284	28,115	$13 0247			
31									
32	Peaking			$4,969,000					
33	Peaking Additional Costs			$0					
34	Subtotal Peaking Costs			$4,969,000	56,738	$7 2982			
35	Total			$22,034,489	164,571	$11.1575			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			1,876,633	11,806	$13 2459			
39	Pipeline - Remaining			10,794,572	67,912	$13 2459			
40	Storage			4,394,284	28,115	$13 0247			
41	Peaking			4,969,000	56,738	$7 2982			
42	Total			22,034,489	164,571	$11.1575			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**44.034%**	826,357	5,199	$13 2459			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**44.034%**	4,753,297	29,904	$13 2459			
48	Storage	Line 40 * Line 13 Col C	**44.034%**	1,934,974	12,380	$13 0247			
49	Peaking	Line 41 * Line 13 Col C	**44.034%**	2,188,059	24,984	$7 2982			
50	Total		**44.034%**	9,702,631	72,467	$11.1575			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2018 - 2019 Winter Cost of Gas Filing
Capacity Assignment Calculations 2016-2017
Derivation of Class Assignments and Weightings

Line							
51							
52							**Ratios for COG**
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		1,050,276	6,608	$13 2459	
55	Pipeline - Remaining	Line 39 - Line 47		6,041,275	38,007	$13 2458	
56	Storage	Line 40 - Line 48		2,459,310	15,735	$13 0248	
57	Peaking	Line 41 - Line 49		2,780,941	31,754	$7 2981	
58	Total		**55.966%**	12,331,802	92,104	$11.1575	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		447,308	2,814	$13 2465	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		5,182,374	32,604	$13 2458	
64	Storage	Line 56 * Line 24 Col F		2,109,664	13,498	$13 0245	
65	Peaking	Line 57 * Line 24 Col F		2,385,568	27,239	$7 2983	
66	Total		**45.9503%**	10,124,914	76,155	$11 0793	**0.9930**
67			42.590%	82%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		602,968	3,794	$13 2439	
71	Pipeline - Remaining	Line 55 - Line 63		858,901	5,403	$13 2473	
72	Storage	Line 56 - Line 64		349,646	2,237	$13 0251	
73	Peaking	Line 57 - Line 65		395,373	4,515	$7 2974	
74	Total		**10.0156%**	2,206,888	15,949	$11 5310	**1.0335**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 13 2459	$ 13.2459	$ 13.2459	
80	Storage			$ 13 0247	$ 13.0247	$ 13.0247	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 11.1575	$ 11.0793	$ 11.5310	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			48.44%	**46.51%**	**57.67%**	
88	Storage			17.08%	**17.72%**	**14.03%**	
89	Peaking			34.48%	**35.77%**	**28.31%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			44.03%	44.43%	11.54%	100.00%
96	Storage			44.03%	48.01%	7.96%	100.00%
97	Peaking			44.03%	48.01%	7.96%	100.00%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**

2 **d/b/a Liberty Utilities**

3 **2017-2018 Winter Calculation**

4 **Correction Factor Calculation**

Line								
5								
6								
7		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	1,321,101	2,319,276	3,165,299	3,498,870	2,926,465	1,918,416	15,149,429
12	G-42	895,704	1,551,977	2,083,542	2,176,169	1,812,337	1,285,485	9,805,213
13	G-43	360,692	504,475	733,059	836,182	731,266	598,340	3,764,015
14	High Winter Use	2,577,497	4,375,729	5,981,900	6,511,221	5,470,068	3,802,241	28,718,657
15								
16	G-51	135,964	177,998	217,956	227,659	210,007	162,636	1,132,220
17	G-52	146,420	183,177	224,756	238,484	224,688	178,727	1,196,252
18	G-53	156,779	249,279	616,066	508,733	461,553	413,241	2,405,652
19	G-54	23,619	24,600	26,018	27,451	27,760	25,474	154,923
21	Low Winter Use	462,782	635,054	1,084,797	1,002,328	924,009	780,077	4,889,046
22								
23	Gross Total	3,040,279	5,010,783	7,066,697	7,513,549	6,394,077	4,582,318	33,607,703
24								

25				
26	Total Sales	33,607,703		
27	Low Winter Use	4,889,046		
28	Winter Ratio for Low Winter Use	**1.0335**	Schedule 10A p 2, ln 74	
29	High Winter Use	28,718,657		
30	Winter Ratio for High Winter Use	**0.9930**	Schedule 10A p 2, ln 66	
31				
32	Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use		
33	Correction Factor =	**100.1110%**		
34				
35				

36 **Allocation Calculation for Miscellaneous Overhead**

37				
38	Projected Winter Sales Volume	11/1/18 - 4/30/19	86,628,921	Sch.10B, ln 23
39	Projected Annual Sales Volume	11/1/18 - 10/31/19	106,815,146	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales		81.10%	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
2018 - 2019 Winter Cost of Gas Filing

Dry Therms

Firm Sales	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Subtotal PK 18-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Subtotal OP 19**	**Total**
R-1	58,148	73,323	85,127	87,489	80,107	60,928	445,123	44,082	30,039	23,238	24,503	31,923	43,218	197,003	642,126
R-3	4,041,030	7,405,866	10,502,345	11,246,925	9,528,683	6,407,575	49,132,423	3,690,099	1,773,275	1,006,300	981,527	1,481,613	2,659,147	11,591,962	60,724,385
R-4	225,090	424,725	668,812	822,921	728,538	573,586	3,443,671	361,052	178,352	90,516	79,349	97,393	150,109	956,771	4,400,443
Total Residential.	4 324 268	7 903 914	11 256 284	12 157 335	10 337 327	7 042 089	53 021 218	4 095 234	1 981 666	1 120 055	1 085 379	1 610 929	2 852 473	12 745 736	65 766 954
G-41	1,321,101	2,319,276	3,165,299	3,498,870	2,926,465	1,918,416	15,149,429	800,746	362,796	221,001	168,493	181,679	460,013	2,194,729	17,344,157
G-42	895,704	1,551,977	2,083,542	2,176,169	1,812,337	1,285,485	9,805,213	748,675	460,256	231,012	116,114	74,965	227,916	1,858,939	11,664,152
G-43	360,692	504,475	733,059	836,182	731,266	598,340	3,764,015	304,113	197,948	134,668	105,947	121,390	192,087	1,056,153	4,820,168
G-51	135,964	177,998	217,956	227,659	210,007	162,636	1,132,220	115,160	74,244	56,098	56,385	71,155	94,990	468,032	1,600,252
G-52	146,420	183,177	224,756	238,484	224,688	178,727	1,196,252	131,291	88,424	68,817	68,840	84,354	107,862	549,588	1,745,840
G-53	156,779	249,279	616,066	508,733	461,553	413,241	2,405,652	291,255	205,865	165,249	156,854	172,243	202,036	1,193,502	3,599,154
G-54	23,619	24,600	26,018	27,451	27,760	25,474	154,923	23,468	19,194	16,830	17,609	20,668	21,777	119,546	274,468
Total C/I	3 040 279	5 010 783	7 066 697	7 513 549	6 394 077	4 582 318	33 607 703	2 414 708	1 408 727	893 675	690 242	726 454	1 306 681	7 440 489	41 048 192
Sales Volume	**7,364,547**	**12,914,697**	**18,322,981**	**19,670,884**	**16,731,404**	**11,624,407**	**86,628,921**	**6,509,942**	**3,390,393**	**2,013,730**	**1,775,621**	**2,337,384**	**4,159,155**	**20,186,225**	**106,815,146**
Transportation Sales															
G-41	575,879	819,379	1,110,280	1,198,083	994,081	780,156	5,477,859	419,152	223,968	126,739	130,012	177,081	307,285	1,384,236	6,862,094
G-42	1,709,642	2,476,139	3,396,451	3,680,772	3,051,299	2,391,810	16,706,114	1,277,699	653,670	331,128	308,102	424,112	829,661	3,824,373	20,530,487
G-43	916,199	1,344,906	1,729,807	1,910,992	1,765,170	1,398,691	9,065,765	1,166,024	718,428	474,845	407,575	463,279	699,961	3,930,112	12,995,877
G-51	42,394	46,822	55,046	63,877	60,806	58,506	327,451	77,824	67,235	64,233	77,040	88,667	80,334	455,334	782,784
G-52	222,033	234,604	257,794	277,352	269,034	248,554	1,509,370	283,695	260,424	264,769	323,847	380,983	356,910	1,870,628	3,379,999
G-53	465,205	609,368	785,673	886,023	881,490	807,226	4,434,985	739,996	529,662	363,450	297,063	282,627	351,494	2,564,292	6,999,276
G-54	2,364,482	2,375,492	2,456,766	2,089,499	2,011,618	1,925,018	13,222,874	1,781,763	1,808,656	1,788,616	1,955,455	2,061,440	2,219,044	11,614,976	24,837,850
Total Trans. Sales	**6,295,834**	**7,906,710**	**9,791,817**	**10,106,599**	**9,033,498**	**7,609,960**	**50,744,418**	**5,746,154**	**4,262,044**	**3,413,780**	**3,499,094**	**3,878,188**	**4,844,690**	**25,643,949**	**76,388,368**
Total All Sales	**13,660,381**	**20,821,407**	**28,114,798**	**29,777,484**	**25,764,902**	**19,234,367**	**137,373,339**	**12,256,096**	**7,652,437**	**5,427,510**	**5,274,715**	**6,215,572**	**9,003,844**	**45,830,174**	**183,203,513**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11A**

Volumes (Therms) **Normal Year**

For the Months of November 18 - April 19

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	796,342	878,932	897,468	806,735	883,624	543,941	4,807,042
Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
TGP Supply (Gulf)	4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382	16,183,681
Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
Dracut Supply 2 - Swing	2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232	11,732,071
ENGIE Combo	-	945,993	1,229,648	1,264,827	734,441	-	4,174,908
LNG Truck	18,690	289,648	685,485	1,029,982	145,597	-	2,169,402
Propane Truck	-	-	356,219	91,328	-	-	447,548
PNGTS	198,251	197,617	108,541	146,415	191,500	201,686	1,044,010
Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	260,087	2,111,074
TGP Supply (Z4)	1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079	12,999,054
Subtotal Pipeline Volumes	10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703	69,847,042
Storage Gas:							
TGP Storage	1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558	19,841,326
Produced Gas:							
LNG Vapor	18,690	289,648	777,271	1,029,982	64,550	19,014	2,199,156
Propane	-	-	859,588	91,328	-	-	950,916
Subtotal Produced Gas	18,690	289,648	1,636,859	1,121,310	64,550	19,014	3,150,073
Less - Gas Refills:							
LNG Truck	(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-	(2,169,402)
Propane	-	-	(356,219)	(91,328)	-	-	(447,548)
TGP Storage Refill	(2,262,867)	-	-	-	-	-	(2,262,867)
Subtotal Refills	(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-	(4,879,817)
Total Sendout Volumes	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276	87,958,623

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Normal and Design Year Volumes

Volumes (Therms) **Design Year**

For the Months of November 18 - April 19

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	796,342	878,932	897,468	806,735	883,624	617,960	4,881,061
Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
TGP Supply (Gulf)	4,154,598	2,956,407	3,018,756	2,713,035	2,876,080	584,686	16,303,562
Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
Dracut Supply 2 - Swing	3,107,938	3,496,465	3,388,088	3,348,710	4,354,285	2,136,377	19,831,864
ENGIE Combo	-	1,277,020	1,048,260	1,113,337	730,137	-	4,168,754
LNG Truck	19,358	54,220	759,788	885,016	452,570	-	2,170,952
Propane Truck	-	-	303,770	144,966	-	-	448,735
PNGTS	198,251	219,020	115,097	158,013	205,844	201,686	1,097,911
Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	311,697	2,162,684
TGP Supply (Z4)	1,641,413	1,819,931	1,858,313	1,670,006	1,829,646	4,234,727	13,054,036
Subtotal Pipeline Volumes	10,889,131	14,422,474	16,991,430	14,861,168	12,410,180	8,723,428	78,297,812
Storage Gas:							
TGP Storage	1,371,738	4,289,074	5,080,310	4,651,952	3,946,183	155,509	19,494,766
							0
Produced Gas:							0
LNG Vapor	18,690	54,933	851,575	885,016	371,524	19,014	2,200,752
Propane	-	-	807,138	144,966	-	-	952,104
Subtotal Produced Gas	18,690	54,933	1,658,713	1,029,982	371,524	19,014	3,152,857
Less - Gas Refills:							
LNG Truck	(19,358)	(54,220)	(759,788)	(885,016)	(452,570)	-	-2,170,952
Propane	-	-	(303,770)	(144,966)	-	-	-448,735
TGP Storage Refill	(1,843,002)	-	-	-	-	-	-1,843,002
Subtotal Refills	(1,862,360)	(54,220)	(1,063,558)	(1,029,982)	(452,570)	-	(4,462,690)
Total Sendout Volumes	10,417,200	18,712,261	22,666,896	19,513,121	16,275,316	8,897,951	96,482,745

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 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	4,807,042	4,000	7,240,000	66%	4,881,061	4,000	7,240,000	67%
Niagara Supply	3,985,274	3,122	5,650,820	71%	3,985,274	3,122	5,650,820	71%
TGP Supply (Gulf + Z4)	29,182,735	21,596	39,088,760	75%	29,357,598	21,596	39,088,760	75%
Dracut Supply 1 & 2	21,925,049	50,000	90,500,000	24%	30,024,841	50,000	90,500,000	33%
LNG Truck	2,169,402	-	-	-	2,170,952	-	-	-
Propane Truck	447,548	-	-	-	448,735	-	-	-
PNGTS	1,044,010	1,000	1,810,000	58%	1,097,911	1,000	1,810,000	61%
Portland Natural Gas	2,111,074	1,784	3,229,040	65%	2,162,684	1,784	3,229,040	67%
Engie Vapor	4,174,908	7,000	6,300,000	66%	4,168,754	7,000	6,300,000	66%
Subtotal Pipeline Volumes	69,847,042				78,297,812			
Storage Gas:								
TGP Storage	19,841,326		25,791,710	77%	19,494,766		25,791,710	76%
Produced Gas:								
LNG Vapor	2,199,156				2,200,752			
Propane	950,916.4				952,104			
Subtotal Produced Gas	3,150,073				3,152,857			
Less - Gas Refills:								
LNG Truck	(2,169,402)				(2,170,952)			
Propane	(447,548)				(448,735)			
TGP Storage Refill	(2,262,867)				(1,843,002)			
Subtotal Refills	(4,879,817)				(4,462,690)			
Total Sendout Volumes	87,958,623				96,482,745			

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2018 / 19 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a Liberty Utilities

Requirements	
Firm Sales	1,188,091
Interruptible Sales	0
Firm Transportation	457,618
Interruptible Transportation	0
Total Requirements	1,645,709
Resources	
Purchased Pipeline Gas	797,180
Underground Storage Gas	281,150
Propane Air Production	269,379
LNG Produced Gas	228,000
Third-Party Supply	70,000
Total Resources	1,645,709

Please refer to the ENNGI 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

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Sr. Manager, Energy Procurement

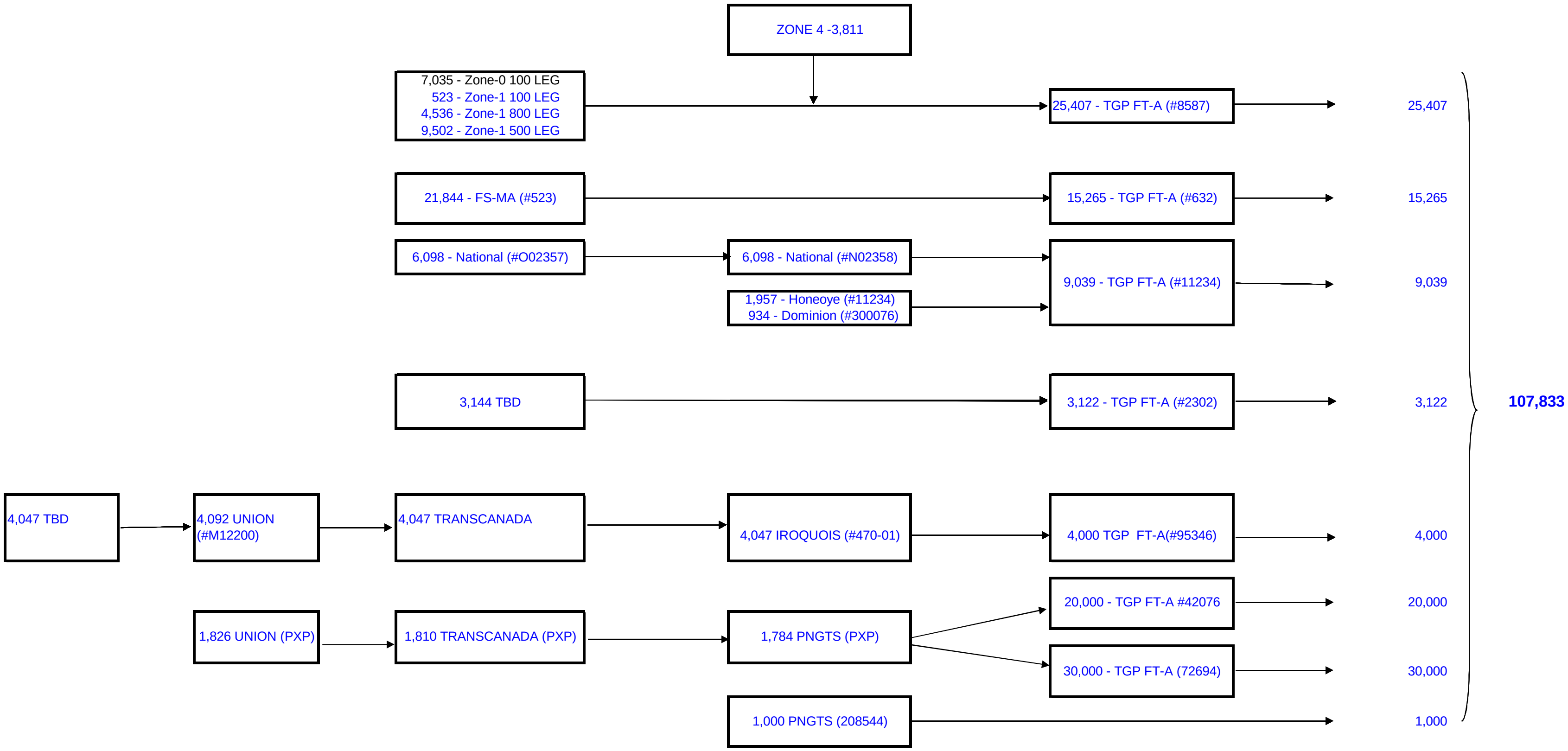
Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.

Peak 2018 - 2019 Winter Cost of Gas Filing

Transportation Available for Pipeline Supply and Storage

(MMBtu)



LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2018 - 2019 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Niagara	NA	NA	Supply	3,147	1,148,655	3/31/2019	N/A	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
ENGIE	FCS		Firm Combination Liquid and Vapor Svc	Up to 10 trucks	730,000	3/31/2019 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2019	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2019	N/A	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/A	
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2021	3/31/2019	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2020	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2022	11/1/2021	Evergreen Provision
Portland Natural Gas Transmission System	FT	208544	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	1,784	651,160	11/1/2019		Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2020	10/31/2019	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	95346	Transportation	4,000	1,460,000	11/30/2021	11/30/2020	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2020	10/31/2019	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2022	10/31/2021	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	1,810	660,650	11/1/2019		Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2022	10/31/2020	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	1,826	666,490	11/1/2019		Precedent Agreement

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2017 - Apr 2018 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	17,503,533	44.21%	74.78%
G-42	12,021,109	30.36%	37.32%
G-43	2,980,868	7.53%	26.68%
G-51	2,767,315	6.99%	72.79%
G-52	2,732,036	6.90%	29.44%
G-53	1,147,046	2.90%	10.71%
G-54	437,495	1.11%	2.32%
Total C/I	39,589,403	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,901,802	8.45%	25.22%
G-42	20,192,111	28.90%	62.68%
G-43	8,191,717	11.72%	73.32%
G-51	1,034,372	1.48%	27.21%
G-52	6,549,487	9.37%	70.56%
G-53	9,561,069	13.68%	89.29%
G-54	18,439,622	26.39%	97.68%
Total C/I	69,870,180	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	23,405,335	21.38%	100.00%
G-42	32,213,221	29.43%	100.00%
G-43	11,172,585	10.21%	100.00%
G-51	3,801,687	3.47%	100.00%
G-52	9,281,523	8.48%	100.00%
G-53	10,708,114	9.78%	100.00%
G-54	18,877,117	17.25%	100.00%
Total C/I	109,459,584	100.00%	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak May 17 - Oct 17 (Therms)	Peak Nov 17-Apr 18 (Therms)	Total May 17 - Apr 18 (Therms)	Ratio
Pipeline Deliveries	17,319,900	88,967,680	106,287,580	
All Others	96,140	2,172,350	2,268,490	
	17,416,040	91,140,030	108,556,070	
Total Winter Supplies				91,140,030
Total Pipeline Deliveries				106,287,580
Ratio Winter Supplies to Pipeline Supplies				0.857

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 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-17**	**Aug-17**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	178,096	235,365	413,461	17,503,533	2.36%
G-42	172,926	162,076	335,002	12,021,109	2.79%
G-43	46,398	59,648	106,045	2,980,868	3.56%
G-51	150,703	147,994	298,696	2,767,315	10.79%
G-52	143,061	156,081	299,142	2,732,036	10.95%
G-53	33,168	61,611	94,779	1,147,046	8.26%
G-54	25,839	35,035	60,874	437,495	13.91%
Total C/I	750,191	857,809	1,608,000	39,589,403	4.06%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2018 - 2019 Winter Cost of Gas Filing

Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas

Underground Storage Gas

		May-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
Beginning Balance (MMBtu)		488,910	744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	488,910
Injections (MMBtu)	Sch 11A ln 38 /10	261,143	221,871	271,295	250,468	250,468	250,468	226,287	-	-	-	-	-	1,731,999
Subtotal		750,053	966,045	1,232,745	1,478,020	1,728,487	1,978,955	2,205,242	2,032,757	1,620,686	1,107,337	596,478	224,165	
Storage Sale/Adjustments		(3,639)	(4,595)	(5,193)			-							
Withdrawals (MMBtu)	Sch 11A ln 28 /10	(2,240)	-		-	-	-	(172,485)	(412,071)	(513,349)	(510,859)	(372,313)	(3,056)	(1,986,373)
Ending Balance (MMBtu)		744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	221,109	234,536
Beginning Balance		$ 1,154,733	$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	1,154,733
Injections	ln 11 * ln 36	$ 662,826	$ 532,338	$ 708,595	$ 674,472	$ 674,472	$ 674,472	$ 627,674	$ -	$ -	$ -	$ -	$ -	$ 4,554,849
Subtotal		$ 1,817,559	$ 2,344,415	$ 3,049,262	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,696,861	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	
Storage Sale/Adjustments		$ (28)	$ (3,747)	$ (3,491)			$ -							
Withdrawals	ln 17 * ln 34	$ (5,454)		$ -	$ -	$ -	$ -	$ (445,586)	$ (1,064,513)	$ (1,326,148)	$ (1,319,717)	$ (961,805)	$ (7,894)	(5,131,118)
Ending Balance		$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	$ 571,197	$ 578,464
Average Rate For Withdrawals	ln 22 /ln 9	$2.4232	$2.4268	$2.4736	$2.5170	$2.5425	$2.5615	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	
TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$2.5382	$2.3993	$2.6119	$2.6928	$2.6928	$2.6928	$2.7738	$2.8701	$2.9440	$2.9077	$2.8132	$2.6365	

For Informational Purposes	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
Summer Hedge Contracts - Vols Dth	-	-	-	-	-	-	-
Average Hedge Price	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
NYMEX	$2.9479	$3.0421	$3.1275	$3.0909	$2.9866	$2.6741	
Hedged Volumes at Hedged Price	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less Hedged Volumes at NYMEX	-	-	-	-	-	-	-
Hedge (Savings)/Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -

		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
Month Dollar Average	ln (22 + ln 32) /2	$ 3,383,007	$ 4,057,479	$ 4,731,951	$ 5,160,231	$ 4,719,018	$ 3,523,688	$ 2,200,755	$ 1,059,994	$ 575,144
Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Inventory Finance Charge	ln 47 * ln 49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Financial Expenses		0	0	0	0	0	0	0	0	0
Total Inventory Finance Charges		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ln	Description	Reference	May-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
40	**Liquid Propane Gas (LPG)**														
43	Beginning Balance		94,161	93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	94,161
45	Injections	Sch 11A ln 37 /10	-	-	42	-	-	-	-	-	35,622	9,133	-	-	44,797
47	Subtotal		94,161	93,982	93,945	93,945	93,945	93,945	93,945	93,945	129,567	52,741	43,608	43,608	
49	Withdrawals	Sch 11A ln 32 /10	(179)	(79)	-	-	-	-	-	-	(85,959)	(9,133)	-	-	(95,350)
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	43,608	43,608
56	Beginning Balance		$ 1,299,502	$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 1,299,502
58	Injections	ln 45 * ln 68	-	-	580	-	-	-	-	-	491,582	126,033	-	-	618,195
60	Subtotal		$ 1,299,502	$ 1,297,032	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,788,103	$ 727,852	$ 601,814	$ 601,814	
62	Withdrawals	ln 51 * ln 66	(2,470)	(1,090)	-	-	-	-	-	-	(1,186,284)	(126,038)	-	-	(1,315,883)
64	Ending Balance		$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 601,814	$ 601,814
66	Average Rate For Withdrawals		$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8006	$13.8005	$13.8005	$13.8005	
68	Propane Rate for Injections	Actual or Sch. 6, ln 158 * 10	$13.8009	$13.8009	$13.8009	$0.0000	$0.0000	$0.0000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 949,170	$ 601,817	$ 601,814	$ 601,814	
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Line			May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
71															
72	**Liquid Natural Gas (LNG)**		May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
73			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
74	Beginning Balance		10,658	9,572	10,498	9,787	10,713	11,639	12,565	12,565	12,565	3,386	3,386	11,491	10,658
75															
76	Injections	Sch 11A ln 36 /10	839	2,657	2,001	2,657	2,657	2,657	1,869	28,965	68,548	102,998	14,560	-	230,408
77															
78	Subtotal		11,497	12,229	12,499	12,444	13,370	14,296	14,434	41,530	81,113	106,385	17,946	11,491	
79															
80	Withdrawals	Sch 11A ln 31 /10	(1,925)	(1,731)	(2,712)	(1,731)	(1,731)	(1,731)	(1,869)	(28,965)	(77,727)	(102,998)	(6,455)	(1,901)	(231,477)
81															
82	Ending Balance		9,572	10,498	9,787	10,713	11,639	12,565	12,565	12,565	3,386	3,386	11,491	9,590	9,590
83															
84															
85	Beginning Balance		$ 54,633	$ 54,814	$ 65,051	$ 65,700	$ 78,110	$ 89,787	$ 100,915	$ 95,062	$ 68,585	$ 16,151	$ 15,601	$ 51,776	$ 54,633
86															
87	Injections	ln 76 * ln 97	11,205	20,961	18,851	25,031	25,031	25,031	8,287	131,625	318,284	473,977	65,260	-	1,123,541
88															
89	Subtotal		$ 65,838	$ 75,775	$ 83,901	$ 90,731	$ 103,141	$ 114,818	$ 109,202	$ 226,687	$ 386,869	$ 490,128	$ 80,861	$ 51,776	
90															
91	Withdrawals	ln 80 * ln 95	(11,024)	(10,724)	(18,201)	(12,621)	(13,354)	(13,902)	(14,140)	(158,102)	(370,718)	(474,527)	(29,085)	(8,567)	(1,134,966)
92															
93	Ending Balance		$ 54,814	$ 65,051	$ 65,700	$ 78,110	$ 89,787	$ 100,915	$ 95,062	$ 68,585	$ 16,151	$ 15,601	$ 51,776	$ 43,209	$ 43,209
94															
95	Average Rate For Withdrawals		$5.7265	$6.1963	$6.7127	$7.2911	$7.7143	$8.0315	$7.5656	$5.4584	$4.7695	$4.6071	$4.5058	$4.5058	
96															
97	LNG Rate for Injections	Actual or Sch. 6, ln 157 * 10	$13.3552	$7.8889	$9.4207	$9.4207	$9.4207	$9.4207	$4.4339	$4.5443	$4.6432	$4.6018	$4.4822	$0.0000	
98															
99															
100	Month Dollar Average	ln (85 + ln 93) /2				$ 71,905	$ 83,949	$ 95,351	$ 97,989	$ 81,823	$ 42,368	$ 15,876	$ 33,689	$ 47,492	
101															
102	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
103															
104	Inventory Finance Charge	ln 100 * ln 102				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
105															
106															
107	Total Fuel Financing	lns 53 + 75 + 104				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 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-18	6,295,834	$0.0005	$ 3,273
Dec-18	7,906,710	0.0005	4,111
Jan-19	9,791,817	0.0005	5,091
Feb-19	10,106,599	0.0005	5,254
Mar-19	9,033,498	0.0005	4,696
Apr-19	7,609,960	0.0005	3,956
Total	**50,744,418**		**$ 26,381**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.

2/ Refer to Proposed First Revised Page 94 for calculation of rate.

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Local Distribution Adjustment Charge (LDAC) increase due to Rate Case Expense and Recoupment
For LDAC effective November 1, 2018 - October 31, 2019

1	Rate Case Expense Remaining from Docket No. DG 14-180	$51,485
2	Rate Case Expense Through June 2018 in Docket No. DG 17-048	$578,477
3	Rate Case Expense for Docket No. DG 17-048 Currently Approved for $530,000	($48,477)
4	Remaining Recoupment from DG 14-180 & DG 17-048	$1,633,854
5	July 1, 2018 Balance	$2,215,339
6	Minus November 2019 & December 2019 Recoupment	($233,408)
7	Minus Estimated Recoveries from July 2018 through October 2018	($312,077)
8	Total Estimated Remaining Recovery As Of November 1, 2018	$1,669,854
9	Estimated November 2018 - October 2019 Interest	$36,303
10	Total Remaining Recovery	$1,706,158
11	Estimated November 2018 - October 2019 Sales (therms)	184,654,874
12	RCE & Recoupment rate per therm November 2018 - October 2019	$0.0092

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Total**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**30**	**31**	**31**	**28**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	
3	Beginning Balance	$ 2,215,339	$ 2,152,980	$ 2,092,394	$ 2,018,719	$ 1,907,454	$ 1,770,590	$ 1,557,222	$ 1,265,114	$ 954,071	$ 684,545	$ 483,022	$ 354,966	$ 275,250	$ 218,798	$ 163,706	$ 98,381	$ 9,733,120
4																		
5	Add Actual Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6																		
7	Less Collected Revenue	(71,614)	(69,582)	(82,105)	(119,584)	(144,406)	(220,419)	(298,088)	(315,291)	(272,886)	(203,997)	(129,775)	(81,051)	(57,499)	(55,876)	(65,880)	(95,294)	(1,940,462)
8																		
9	Add Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																		
11	Ending Balance Pre-Interest	$ 2,143,725	$ 2,083,399	$ 2,010,289	$ 1,899,135	$ 1,763,048	$ 1,550,171	$ 1,259,134	$ 949,823	$ 681,185	$ 480,548	$ 353,247	$ 273,915	$ 217,751	$ 162,922	$ 97,826	$ 3,087	**$ 7,792,658**
12																		
13	Month's Average Balance	$ 2,179,532	$ 2,118,190	$ 2,051,341	$ 1,958,927	$ 1,835,251	$ 1,660,381	$ 1,408,178	$ 1,107,468	$ 817,628	$ 582,547	$ 418,135	$ 314,440	$ 246,501	$ 190,860	$ 130,766	$ 50,734	
14																		
15	Interest Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
16																		
17	Interest Applied	$ 9 256	$ 8 995	$ 8 430	$ 8 319	$ 7 542	$ 7 051	$ 5 980	$ 4 248	$ 3 360	$ 2 474	$ 1 718	$ 1 335	$ 1 047	$ 784	$ 555	$ 208	**36,303**
18																		
19	Ending Balance	**$ 2,152,980**	**$ 2,092,394**	**$ 2,018,719**	**$ 1,907,454**	**$ 1,770,590**	**$ 1,557,222**	**$ 1,265,114**	**$ 954,071**	**$ 684,545**	**$ 483,022**	**$ 354,966**	**$ 275,250**	**$ 218,798**	**$ 163,706**	**$ 98,381**	**$ 3,296**	

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Lost Revenue Adjustment Factor (LRAM)
For LDAC effective November 1, 2018 - October 31, 2019

	Residential	
1	October 31, 2018 Projected Balance (LRAM true-up)	$18,706
2	Calculated Lost Distr bution Revenue - November 2018 through October 2019	$0
3	Calculated Interest - November 2018 through October 2019	$957
4		
5	Total to be recovered	$19,663
6		
7	Estimated November 2018 - October 2019 Sales (therms)	66,050,202
8		
9	LRAM residential rate per therm November 2018 - October 2019	$0.0003
	Commercial & Industrial	
10	October 31, 2018 Projected Balance (LRAM true-up)	$13,218
11	Calculated Lost Distr bution Revenue - November 2018 through October 2019	$0
12	Calculated Interest - November 2018 through October 2019	$676
13		
14	Total to be recovered	$13,894
15		
16	Estimated November 2018 - October 2019 Sales (therms)	118,604,671
17		
18	LRAM C&I rate per therm November 2018 - October 2019	$0.0001

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
Lost Revenue Adjustment Mechanism

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
	RESIDENTIAL													
3	Beginning Balance (LRAM true-up)	$ 18,706	$ 18,783	$ 18,863	$ 18,943	$ 19,015	$ 19,096	$ 19,175	$ 19,256	$ 19,335	$ 19,417	$ 19,500	$ 19,580	**$ 229,669**
4														
5	Add: Lost Distribution Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Less: Lost Distribution Revenue Collections	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-	-	**-**
10														
11	Ending Balance Pre-Interest	$ 18,706	$ 18,783	$ 18,863	$ 18,943	$ 19,015	$ 19,096	$ 19,175	$ 19,256	$ 19,335	$ 19,417	$ 19,500	$ 19,580	**$ 229,669**
12														
13	Month's Average Balance	$ 18,706	$ 18,783	$ 18,863	$ 18,943	$ 19,015	$ 19,096	$ 19,175	$ 19,256	$ 19,335	$ 19,417	$ 19,500	$ 19,580	
14														
15	Interest Rate	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	
16														
17	Interest Applied	$ 77	$ 80	$ 80	$ 73	$ 81	$ 78	$ 81	$ 79	$ 82	$ 82	$ 80	$ 83	**957**
18														
19	Ending Balance	**$ 18,783**	**$ 18,863**	**$ 18,943**	**$ 19,015**	**$ 19,096**	**$ 19,175**	**$ 19,256**	**$ 19,335**	**$ 19,417**	**$ 19,500**	**$ 19,580**	**$ 19,663**	
	COMMERCIAL & INDUSTRIAL													
3	Beginning Balance	$ 13,218	$ 13,272	$ 13,328	$ 13,385	$ 13,436	$ 13,493	$ 13,549	$ 13,606	$ 13,662	$ 13,720	$ 13,778	$ 13,835	**$ 162,283**
4														
5	Add: Lost Distribution Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Less: Lost Distribution Revenue Collections	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-	-	**-**
10														
11	Ending Balance Pre-Interest	$ 13,218	$ 13,272	$ 13,328	$ 13,385	$ 13,436	$ 13,493	$ 13,549	$ 13,606	$ 13,662	$ 13,720	$ 13,778	$ 13,835	**$ 162,283**
12														
13	Month's Average Balance	$ 13,218	$ 13,272	$ 13,328	$ 13,385	$ 13,436	$ 13,493	$ 13,549	$ 13,606	$ 13,662	$ 13,720	$ 13,778	$ 13,835	
14														
15	Interest Rate	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	
16														
17	Interest Applied	$ 54	$ 56	$ 57	$ 51	$ 57	$ 55	$ 58	$ 56	$ 58	$ 58	$ 57	$ 59	**676**
18														
19	Ending Balance	**$ 13,272**	**$ 13,328**	**$ 13,385**	**$ 13,436**	**$ 13,493**	**$ 13,549**	**$ 13,606**	**$ 13,662**	**$ 13,720**	**$ 13,778**	**$ 13,835**	**$ 13,894**	

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities
Revenue Decoupling Adjustment Clause (RDAC)
Benchmark Revenue Per Customer effective November 1, 2018 - October 31, 2019

EnergyNorth Natural Gas Inc

2016 Customers (Equivalent Bills)

	S&T Jan-16	S&T Feb-16	S&T Mar-16	S&T Apr-16	S&T May-16	S&T Jun-16	S&T Jul-16	S&T Aug-16	S&T Sep-16	S&T Oct-16	S&T Nov-16	S&T Dec-16	S&T Total	S&T Winter	S&T Summer
R-1	3,744	3,378	3,449	4,027	3,010	3,634	3,658	3,457	3,579	4,017	2,993	3,746	42,693	21,338	21,354
R-3	76,501	70,269	71,991	75,178	68,613	73,366	74,096	70,010	70,749	71,998	68,057	74,878	865,706	436,874	428,832
R-4	5,629	5,175	5,301	5,515	5,072	5,405	5,462	5,162	5,214	5,293	5,032	5,519	63,778	32,171	31,607
Total Resid.	**85,874**	**78,822**	**80,741**	**84,721**	**76,695**	**82,405**	**83,216**	**78,628**	**79,542**	**81,308**	**76,081**	**84,144**	**972,177**	**490,383**	**481,794**
G-41	9,712	8,893	9,107	9,817	8,436	9,306	9,383	8,871	8,994	9,400	8,360	9,482	109,763	55,371	54,392
G-42	1,856	1,708	1,749	1,830	1,665	1,783	1,802	1,705	1,723	1,758	1,653	1,820	21,055	10,618	10,437
G-43	51	47	48	49	47	49	50	47	47	47	47	50	579	293	286
G-51	1,435	1,309	1,335	1,484	1,218	1,385	1,399	1,324	1,350	1,453	1,207	1,419	16,319	8,189	8,129
G-52	345	316	323	346	302	331	335	316	320	333	299	338	3,903	1,967	1,936
G-53	34	31	32	33	30	32	33	31	31	32	30	33	382	192	190
G-54	28	25	26	27	25	26	27	25	26	26	25	27	314	159	155
G-63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total C/I	**13,462**	**12,330**	**12,621**	**13,587**	**11,723**	**12,912**	**13,030**	**12,318**	**12,492**	**13,050**	**11,620**	**13,169**	**152,314**	**76,789**	**75,525**
Total All	**99,336**	**91,153**	**93,361**	**98,308**	**88,418**	**95,317**	**96,246**	**90,947**	**92,034**	**94,358**	**87,701**	**97,312**	**1,124,491**	**567,172**	**557,319**

2016 Calendar BF Base Normal Revenue Adjusted

	S&T Jan-16	S&T Feb-16	S&T Mar-16	S&T Apr-16	S&T May-16	S&T Jun-16	S&T Jul-16	S&T Aug-16	S&T Sep-16	S&T Oct-16	S&T Nov-16	S&T Dec-16	S&T Total	S&T Winter	S&T Summer
R-1	$ 99,555	$ 88,904	$ 84,658	$ 87,561	$ 63,153	$ 71,014	$ 67,806	$ 63,843	$ 67,363	$ 83,474	$ 71,184	$ 96,733	$ 945,249	$ 528,595	$ 416,654
R-3	$ 6,925,912	$ 6,006,068	$ 5,267,976	$ 3,465,023	$ 2,308,483	$ 1,894,274	$ 1,686,231	$ 1,601,723	$ 1,797,279	$ 2,621,900	$ 4,000,612	$ 5,910,427	$ 43,485,908	$ 31,576,019	$ 11,909,890
R-4	$ 191,604	$ 163,736	$ 153,105	$ 109,479	$ 66,579	$ 56,646	$ 50,195	$ 48,023	$ 51,492	$ 74,427	$ 112,783	$ 166,171	$ 1,244,239	$ 896,878	$ 347,362
Total Resid.	**$ 7,217,070**	**$ 6,258,708**	**$ 5,505,739**	**$ 3,662,064**	**$ 2,438,215**	**$ 2,021,934**	**$ 1,804,232**	**$ 1,713,589**	**$ 1,916,134**	**$ 2,779,801**	**$ 4,184,580**	**$ 6,173,330**	**$ 45,675,396**	**$ 33,001,491**	**$ 12,673,906**
G-41	$ 2,084,709	$ 1,824,070	$ 1,593,272	$ 1,184,307	$ 760,116	$ 682,994	$ 636,636	$ 598,503	$ 651,545	$ 868,129	$ 1,183,786	$ 1,783,044	$ 13,851,112	$ 9,653,189	$ 4,197,923
G-42	$ 2,376,642	$ 2,026,762	$ 1,748,029	$ 1,273,283	$ 799,478	$ 633,411	$ 536,535	$ 496,294	$ 605,841	$ 946,447	$ 1,380,050	$ 2,082,157	$ 14,904,929	$ 10,886,922	$ 4,018,006
G-43	$ 445,762	$ 366,776	$ 321,395	$ 215,283	$ 99,097	$ 72,082	$ 63,481	$ 61,834	$ 74,272	$ 72,723	$ 310,606	$ 382,910	$ 2,486,221	$ 2,042,733	$ 443,489
G-51	$ 190,836	$ 167,526	$ 157,125	$ 150,462	$ 117,288	$ 120,789	$ 121,237	$ 115,727	$ 121,591	$ 147,973	$ 141,856	$ 183,563	$ 1,735,974	$ 991,369	$ 744,605
G-52	$ 232,548	$ 208,796	$ 195,007	$ 180,976	$ 114,350	$ 113,547	$ 116,020	$ 113,151	$ 117,269	$ 146,165	$ 190,559	$ 227,888	$ 1,956,276	$ 1,235,774	$ 720,502
G-53	$ 184,285	$ 170,488	$ 174,839	$ 156,845	$ 75,894	$ 70,319	$ 71,880	$ 73,973	$ 72,595	$ 92,579	$ 156,563	$ 211,648	$ 1,511,909	$ 1,054,669	$ 457,240
G-54	$ 123,294	$ 94,963	$ 76,772	$ 90,647	$ 50,657	$ 62,751	$ 64,406	$ 66,555	$ 74,341	$ 87,455	$ 111,999	$ 137,467	$ 1,041,309	$ 635,143	$ 406,166
G-63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total C/I	**$ 5,638,076**	**$ 4,859,381**	**$ 4,266,440**	**$ 3,251,804**	**$ 2,016,880**	**$ 1,755,893**	**$ 1,610,194**	**$ 1,526,037**	**$ 1,717,455**	**$ 2,361,472**	**$ 3,475,420**	**$ 5,008,678**	**$ 37,487,730**	**$ 26,499,799**	**$ 10,987,931**
Total All	**$ 12,855,147**	**$ 11,118,089**	**$ 9,772,179**	**$ 6,913,867**	**$ 4,455,095**	**$ 3,777,827**	**$ 3,414,426**	**$ 3,239,626**	**$ 3,633,589**	**$ 5,141,273**	**$ 7,659,999**	**$ 11,182,008**	**$ 83,163,126**	**$ 59,501,290**	**$ 23,661,837**

Base Revenue Per Customer

	S&T Jan-16	S&T Feb-16	S&T Mar-16	S&T Apr-16	S&T May-16	S&T Jun-16	S&T Jul-16	S&T Aug-16	S&T Sep-16	S&T Oct-16	S&T Nov-16	S&T Dec-16
R-1	$ 26.589	$ 26 316	$ 24.543	$ 21.741	$ 20.979	$ 19.542	$ 18 534	$ 18.470	$ 18.823	$ 20.783	$ 23.785	$ 25 821
R-3	$ 90.533	$ 85.472	$ 73.176	$ 46.091	$ 33.645	$ 25.819	$ 22.757	$ 22 878	$ 25.404	$ 36.416	$ 58.783	$ 78 934
R-4	$ 34.041	$ 31.639	$ 28.884	$ 19.850	$ 13.127	$ 10.481	$ 9.190	$ 9 304	$ 9 875	$ 14.060	$ 22.415	$ 30.106
Total Resid.	**$ 84.043**	**$ 79.403**	**$ 68.190**	**$ 43.225**	**$ 31.791**	**$ 24.537**	**$ 21.681**	**$ 21.794**	**$ 24.090**	**$ 34.189**	**$ 55.001**	**$ 73.367**
G-41	$ 214.643	$ 205.102	$ 174.951	$ 120.636	$ 90.099	$ 73 391	$ 67 847	$ 67.468	$ 72.441	$ 92.350	$ 141.604	$ 188.055
G-42	$ 1,280.188	$ 1,186 317	$ 999.487	$ 695.694	$ 480.054	$ 355 242	$ 297.683	$ 291.098	$ 351.520	$ 538.337	$ 834.753	$ 1,143.792
G-43	$ 8,803.769	$ 7,748 822	$ 6,658.698	$ 4,355.038	$ 2,128.057	$ 1,483.170	$ 1,280.724	$ 1,315.618	$ 1,576.904	$ 1,533.165	$ 6,655.855	$ 7,622.644
G-51	$ 132.941	$ 127 993	$ 117.720	$ 101.392	$ 96.328	$ 87.191	$ 86.636	$ 87.436	$ 90.047	$ 101.832	$ 117.551	$ 129 325
G-52	$ 673.394	$ 660 268	$ 603.678	$ 523.102	$ 378.311	$ 343 526	$ 346.774	$ 358 299	$ 366.393	$ 439.111	$ 637.600	$ 675.157
G-53	$ 5,463.060	$ 5,529 375	$ 5,401.786	$ 4,719.552	$ 2,563.988	$ 2,172 593	$ 2,154 233	$ 2,353 335	$ 2,354.440	$ 2,893.096	$ 5,307.204	$ 6,505 579
G-54	$ 4,392.936	$ 3,788.457	$ 2,919.066	$ 3,300.283	$ 2,034.434	$ 2,398.153	$ 2,367 866	$ 2,683.658	$ 2,877.719	$ 3,372.308	$ 4,534.380	$ 5,060.135
G-63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total C/I	**$ 418.808**	**$ 394.103**	**$ 338.054**	**$ 239.324**	**$ 172.048**	**$ 135.986**	**$ 123.577**	**$ 123.882**	**$ 137.487**	**$ 180.958**	**$ 299.101**	**$ 380.345**
Total All	**$ 129.411**	**$ 121.972**	**$ 104.670**	**$ 70.329**	**$ 50.387**	**$ 39.634**	**$ 35.476**	**$ 35.621**	**$ 39.481**	**$ 54.487**	**$ 87.342**	**$ 114.908**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

Ln		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 15.0200	$ 0.5631	$ 0.5631		
3	R-4 Rate at 40% of R-3	$ 6.0000	$ 0.2252	$ 0.2252		
4	Program Subsidy	$ 9.0200	$ 0.3379	$ 0.3379		
5	Average Annual Therms		488	177	666	
6						
7	Peak Period RLIAP Subsidy	$ 54.12	$ 164.96	$ 59.95	$ 279.03	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 15.0200	$ 0.5631	$ 0.5631		
11	R-4 Rate at 40% of R-3	$ 6.0000	$ 0.2252	$ 0.2252		
12	Program Subsidy	$ 9.0200	$ 0.3379	$ 0.3379		
13	Average Annual Therms		86	19	105	
14						
15	Off Peak Period RLIAP Subsidy	$ 54.12	$ 29.01	$ 6.52	$ 89.66	
16						
17	Estimated Annual Subsidy	$ 108.24	$ 193.97	$ 66.47	$ 368.69	
18						
19	Number of Estimated 2018/19 Participants				5,056	1/
20						
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				$ 1,864,087	
22	Prior Year Ending Balance - RLIAP Page 2				545,077	
23	Estimated Annual Administrative Costs				-	
24	Total Program Costs				$ 2,409,164	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/19 sales and transportation				184,654,874	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0130**	

1/ Estimated number of participants for 2018/19 is based on the actual number participants as of July 2018.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2017 THROUGH OCTOBER 2018
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.6

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ 274,360	$ 312,789	$ 322,168	$ 301,407	$ 300,711	$ 329,018	$ 389,796	$ 452,669	$ 486,283	$ 513,560	$ 536,461	$ 550,354	$ 274,360
4														
5	Add: Actual Costs	109,422 7	197,516 7	264,588 9	251,523 7	230,439 8	256,731 6	184,560 1	108,030 1	76,084	70,157	70,050	77,440	1,896,544
6														
7	Less: Collected Revenue	(72,016 8)	(189,281 6)	(286,473 3)	(253,200 1)	(203,333 3)	(197,354 2)	(123,328 7)	(76,245 4)	(50,926)	(49,480)	(58,385)	(85,038)	(1,645,062)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ 311,766	$ 321,024	$ 300,284	$ 299,731	$ 327,817	$ 388,396	$ 451,028	$ 484,454	$ 511,441	$ 534,236	$ 548,126	$ 542,756	**$ 525,841**
12														
13	Month's Average Balance	$ 293,063	$ 316,907	$ 311,226	$ 300,569	$ 314,264	$ 358,707	$ 420,412	$ 468,561	$ 498,862	$ 523,898	$ 542,293	$ 546,555	
14														
15	Interest Rate	4 25%	4 50%	4 50%	4 50%	4 75%	4 75%	4 75%	5 00%	5 00%	5 00%	5 00%	5 00%	
16														
17	Interest Applied	$ 1,024	$ 1,144	$ 1,123	$ 980	$ 1,201	$ 1,400	$ 1,641	$ 1,829	$ 2,118	$ 2,225	$ 2,229	$ 2,321	**19,236**
18														
19	Ending Balance	**$ 312,789**	**$ 322,168**	**$ 301,407**	**$ 300,711**	**$ 329,018**	**$ 389,796**	**$ 452,669**	**$ 486,283**	**$ 513,560**	**$ 536,461**	**$ 550,354**	**$ 545,077**	**$ 545,077**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2018 - October 31, 2019
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	Incentive	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 18	Actual	(2,240,400)	($0.0516)	(227,299)	265,627	169,251	35,820	12,775	(2,249,854)	(2,245,127)	4.75%	(6,227)	(2,256,081)	3,349,634	4,405,040	31
June 18	Actual	(2,256,081)	($0.0516)	(92,112)	265,627	148,594	32,579	12,775	(2,154,245)	(2,205,163)	4.75%	(6,267)	(2,160,512)	1,984,898	1,785,463	30
July 18	Forecast	(2,160,512)	($0.0516)	(64,816)	265,627	101,545	8,281	12,775	(2,102,728)	(2,131,620)	5.00%	(3,349)	(2,106,077)	1,252,661	1,256,417	31
August 18	Forecast	(2,106,077)	($0.0516)	(54,524)	265,627	0	0		(1,894,974)	(2,000,525)	5.00%	(8,495)	(1,903,469)	1,056,675	0	31
September 18	Forecast	(1,903,469)	($0.0516)	(58,985)	265,627	0	0		(1,696,827)	(1,800,148)	5.00%	(7,398)	(1,704,225)	1,143,113	0	30
October 18	Forecast	(1,704,225)	($0.0516)	(87,386)	265,627	0	0		(1,525,984)	(1,615,104)	5.00%	(6,859)	(1,532,843)	1,693,533	0	31
November 18	Forecast	(1,532,843)	($0.0450)	(195,314)	265,627	0	0		(1,462,529)	(1,497,686)	5.00%	(6,155)	(1,468,684)	4,340,302	0	30
December 18	Forecast	(1,468,684)	($0.0450)	(357,114)	265,627	0	0		(1,560,171)	(1,514,428)	5.00%	(6,431)	(1,566,602)	7,935,861	0	31
January 19	Forecast	(1,566,602)	($0.0450)	(509,038)	404,158	0	0		(1,671,483)	(1,619,043)	5.00%	(6,875)	(1,678,358)	11,311,961	0	31
February 19	Forecast	(1,678,358)	($0.0450)	(549,085)	404,158	0	0		(1,823,286)	(1,750,822)	5.00%	(6,715)	(1,830,001)	12,201,886	0	28
March 19	Forecast	(1,830,001)	($0.0450)	(467,012)	404,158	0	0		(1,892,856)	(1,861,428)	5.00%	(7,905)	(1,900,760)	10,378,048	0	31
April 19	Forecast	(1,900,760)	($0.0450)	(318,535)	404,158	0	0		(1,815,138)	(1,857,949)	5.00%	(7,635)	(1,822,773)	7,078,549	0	30
May 19	Forecast	(1,822,773)	($0.0450)	(184,988)	404,158	0	0		(1,603,603)	(1,713,188)	5.00%	(7,275)	(1,610,878)	4,110,836	0	31
June 19	Forecast	(1,610,878)	($0.0450)	(89,586)	404,158	0	0		(1,296,307)	(1,453,593)	5.00%	(5,974)	(1,302,280)	1,990,802	0	30
July 19	Forecast	(1,302,280)	($0.0450)	(50,671)	404,158	0	0		(948,794)	(1,125,537)	5.00%	(4,780)	(953,574)	1,126,024	0	31
August 19	Forecast	(953,574)	($0.0450)	(49,093)	404,158	0	0		(598,509)	(776,041)	5.00%	(3,296)	(601,805)	1,090,959	0	31
September 19	Forecast	(601,805)	($0.0450)	(72,834)	404,158	0	0		(270,481)	(436,143)	5.00%	(1,792)	(272,273)	1,618,528	0	30
October 19	Forecast	(272,273)	($0.0450)	(128,990)	404,158	0	0		2,894	(134,690)	5.00%	(572)	2,322	2,866,447	0	31
November 19	Forecast	2,322	($0.0450)	(195,314)	404,158	0	0		211,166	106,744	5.00%	439	211,605	4,340,302	0	30
December 19	Forecast	211,605	($0.0450)	(357,114)	404,158	0	0		258,648	235,127	5.00%	998	259,647	7,935,861	0	31

Estimated Residential Conservation Charge		
Effective November 1, 2018 - October 31, 2019		
Beginning Balance	$	(1,532,843)
Program Budget Nov 18-Oct 19		4,572,829
Projected Interest		(65,405)
Projected Budget with Interest	$	2,974,581
Total Charges	**$**	**2,974,581**
Projected Therm Sales		**66,050,202**
Residential Rate		**$0.0450**
Total Charges with Interest	**$**	**2,972,259**
Projected Therm Sales		**66,050,202**
Residential Rate		**$0.0450**

Residential Non Heating Therm Sales	0%	778,066	642,126	0%
Residential Heating Therm Sales	35%	65,862,804	65,408,076	35%
C&I Therm Sales	62%	115,871,154	118,604,671	64%
Total Therms	100%	**186,909,214**	**184,654,874**	100%
		Budget 2018	Budget 2019	
Low-Income Program Budget		$ 1,217,300	$ 1,310,342	
Other Refund		-	-	
Total Shared Budget		**$ 1,005,700**	**$ 1,310,342**	
Residential Program Budget		$ 2,362,534	$ 4,163,210	
Residential Program Incentive @ 70%		$ 196,891	$ 217,977	
Total Residential Program Budget		**$ 2,559,425**	**$ 4,381,187**	
Commercial/Industrial Program Budget		$ 3,580,741	$ 4,419,684	
Commercial/Industrial Program Incentive at 70%		$ 196,941	$ 205,958	
Total Commercial/Industrial Program Budget		**$ 3,777,682**	**$ 4,625,642**	
Total Program Budget		**$ 7,554,407**	**$ 10,317,171**	
Shared Expenses Allocation to Residential		$ 436,990	$ 468,703	
Shared Expenses Allocation to C&I		780,310	841,639	
Total Allocated Shared Expenses		**$ 1,217,300**	**$ 1,310,342**	
Total Residential (including allocation of Shared Budget)		$ 2,996,415	$ 4,849,890	
Total C&I (including allocation of Shared Budget)		4,557,992	5,467,281	
Total Budget		**$ 7,554,407**	**$ 10,317,171**	

Estimated Residential Conservation Charge		
Effective November 1, 2018 - October 31, 2019		
Beginning Balance	$	(1,532,842.79)
Program Budget Nov 18-Oct 19	$	4,182,242.33
Projected Interest	$	(61,190.00)
Projected Budget with Interest	$	2,588,209.55
Total Charges	$	2,588,209.55

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2018 - October 31, 2019
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures C&I	Actual DSM Expenditures Low-Income	Incentive	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	Actual Commercial/ Industrial Therm Sales	# of Days
May 18	Actual	(1,094,665)	($0.0219)	(158,066)	245,987	106,016	43,216	9,778	(1,093,721)	(1,094,193)	4.75%	(3,717)	(1,097,438)	6,537,363	7,299,008	31
June 18	Actual	(1,097,438)	($0.0219)	(131,661)	245,987	198,094	13,943	9,778	(1,007,284)	(1,052,361)	4.75%	(3,676)	(1,010,960)	5,092,563	6,011,635	30
July 18	Forecast	(1,010,960)	($0.0219)	(87,792)	245,987	0	0		(852,765)	(931,862)	5.00%	(3,957)	(856,722)	4,008,754	0	31
August 18	Forecast	(856,722)	($0.0219)	(84,349)	245,987	0	0		(695,084)	(775,903)	5.00%	(3,295)	(698,379)	3,851,567	0	31
September 18	Forecast	(698,379)	($0.0219)	(91,025)	245,987	0	0		(543,418)	(620,898)	5.00%	(2,552)	(545,969)	4,156,413	0	30
October 18	Forecast	(545,969)	($0.0219)	(109,234)	245,987	0	0		(409,216)	(477,593)	5.00%	(2,028)	(411,245)	4,987,864	0	31
November 18	Forecast	(411,245)	($0.0387)	(363,835)	245,987	0	0		(529,092)	(470,168)	5.00%	(1,932)	(531,025)	9,401,414	0	30
December 18	Forecast	(531,025)	($0.0387)	(504,619)	245,987	0	0		(789,657)	(660,341)	5.00%	(2,804)	(792,461)	13,039,253	0	31
January 19	Forecast	(792,461)	($0.0387)	(659,998)	455,607	0	0		(996,852)	(894,657)	5.00%	(3,799)	(1,000,651)	17,054,214	0	31
February 19	Forecast	(1,000,651)	($0.0387)	(688,909)	455,607	0	0		(1,233,953)	(1,117,302)	5.00%	(4,286)	(1,238,239)	17,801,261	0	28
March 19	Forecast	(1,238,239)	($0.0387)	(603,328)	455,607	0	0		(1,385,960)	(1,312,099)	5.00%	(5,572)	(1,391,532)	15,589,859	0	31
April 19	Forecast	(1,391,532)	($0.0387)	(477,319)	455,607	0	0		(1,413,244)	(1,402,388)	5.00%	(5,763)	(1,419,007)	12,333,818	0	30
May 19	Forecast	(1,419,007)	($0.0387)	(318,833)	455,607	0	0		(1,282,233)	(1,350,620)	5.00%	(5,736)	(1,287,969)	8,238,574	0	31
June 19	Forecast	(1,287,969)	($0.0387)	(221,442)	455,607	0	0		(1,053,803)	(1,170,886)	5.00%	(4,812)	(1,058,615)	5,722,003	0	30
July 19	Forecast	(1,058,615)	($0.0387)	(168,174)	455,607	0	0		(771,183)	(914,899)	5.00%	(3,885)	(775,068)	4,345,591	0	31
August 19	Forecast	(775,068)	($0.0387)	(163,556)	455,607	0	0		(483,018)	(629,043)	5.00%	(2,671)	(485,689)	4,226,257	0	31
September 19	Forecast	(485,689)	($0.0387)	(179,980)	455,607	0	0		(210,062)	(347,876)	5.00%	(1,430)	(211,492)	4,650,649	0	30
October 19	Forecast	(211,492)	($0.0387)	(240,009)	455,607	0	0		4,106	(103,693)	5.00%	(440)	3,666	6,201,778	0	31
November 19	Forecast	3,666	($0.0387)	(363,835)	455,607	0	0		95,437	49,552	5.00%	204	95,641	9,401,414	0	30
December 19	Forecast	95,641	($0.0387)	(504 619)	455,607	0	0		46 629	71,135	5.00%	302	46 931	13,039,253	0	31
Total 11/2018 - 10/2019				**$ (4,590,001)**	**$ 5,048,041**	0						**$ (43,130)**		118,604,671	0	

Estimated C&I Conservation Charge **November 1, 2018 - October 31, 2019**	
Beginning Balance	(411,245)
Program Budget Nov 18-Oct 19	**5,048,041**
Projected Interest	(43,107)
Program Budget with Interest	4,593,690
Total Charges	**$4,593,690**
Projected Therm Sales	**118,604,671**
C&I Rate	$0.0387
Total Charges with Interest	**$4,590,001**
Projected Therm Sales	**118,604,671**
C&I Rate	**$0.0387**
C&I Rate from Prior Programs	**$0.0000**
Combined C&I Rate	**$0.0387**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2018 - October 31, 2019
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	C&I	Low-Income	Total	Incentive	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	Actual Therm Sales	# of Days
May 18	Actual	(3,335,065)	n/a	(385,365)	511,614	169,251	106,016	79,036	354,303	22,553	(3,343,575)	(3,339,320)	**4.75%**	(13,472)	(3,357,046)	9,886,997	11,704,048	31
June 18	Actual	(3,353,519)	n/a	(223,773)	511,614	148,594	198,094	46,522	393,210	22,553	(3,161,529)	(3,257,524)	4 75%	(12,718)	(3,174,247)	7,077,460	7,797,098	30
July 18	Forecast	(3,171,472)	n/a	(152,607)	511,614	101,545	0	8,281	109,825		(3,214,254)	(3,192,863)	5 00%	(13,559)	(3,227,813)	5,261,414	1,256,417	31
August 18	Forecast	(2,962,798)	n/a	(138,874)	511,614	0	0	0	0		(2,590,058)	(2,776,428)	5 00%	(11,790)	(2,601,848)	4,908,241	0	31
September 18	Forecast	(2,601,848)	n/a	(150,010)	511,614	0	0	0	0		(2,240,245)	(2,421,047)	5 00%	(9,950)	(2,250,194)	5,299,526	0	30
October 18	Forecast	(2,250,194)	n/a	(196,621)	511,614	0	0	0	0		(1,935,201)	(2,092,697)	5 00%	(8,887)	(1,944,087)	6,681,398	0	31
November 18	Forecast	(1,944,087)	n/a	(559,148)	511,614	0	0	0	0		(1,991,622)	(1,967,855)	5 00%	(8,087)	(1,999,709)	13,741,716	0	30
December 18	Forecast	(1,999,709)	n/a	(861,733)	511,614	0	0	0	0		(2,349,828)	(2,174,768)	5 00%	(9,235)	(2,359,063)	20,975,114	0	31
January 19	Forecast	(2,359,063)	n/a	(1,169,036)	859,764	0	0	0	0		(2,668,335)	(2,513,699)	5 00%	(10,675)	(2,679,010)	28,366,175	0	31
February 19	Forecast	(2,679,010)	n/a	(1,237,994)	859,764	0	0	0	0		(3,057,239)	(2,868,124)	5 00%	(11,001)	(3,068,240)	30,003,147	0	28
March 19	Forecast	(3,068,240)	n/a	(1,070,340)	859,764	0	0	0	0		(3,278,816)	(3,173,528)	5 00%	(13,477)	(3,292,292)	25,967,908	0	31
April 19	Forecast	(3,292,292)	n/a	(795,853)	859,764	0	0	0	0		(3,228,381)	(3,260,337)	5 00%	(13,399)	(3,241,780)	19,412,367	0	30
May 19	Forecast	(3,241,780)	n/a	(503,820)	859,764	0	0	0	0		(2,885,836)	(3,063,808)	5 00%	(13,011)	(2,898,847)	12,349,409	0	31
June 19	Forecast	(2,898,847)	n/a	(311,028)	859,764	0	0	0	0		(2,350,110)	(2,624,479)	5 00%	(10,786)	(2,360,896)	7,712,805	0	30
July 19	Forecast	(2,360,896)	n/a	(218,845)	859,764	0	0	0	0		(1,719,977)	(2,040,436)	5 00%	(8,665)	(1,728,642)	5,471,615	0	31
August 19	Forecast	(1,728,642)	n/a	(212,649)	859,764	0	0	0	0		(1,081,527)	(1,405,084)	5 00%	(5,967)	(1,087,494)	5,317,216	0	31
September 19	Forecast	(1,087,494)	n/a	(252,814)	859,764	0	0	0	0		(480,543)	(784,018)	5 00%	(3,222)	(483,765)	6,269,177	0	30
October 19	Forecast	(483,765)	n/a	(368,999)	859,764	0	0	0	0		7,000	(238,383)	5 00%	(1,012)	5,988	9,068,225	0	31
November 19	Forecast	5,988	n/a	(559,149)	859,764	0	0	0	0		306,603	156,296	5 00%	642	307,246	13,741,716	0	30
December 19	Forecast	307,246	n/a	(861,733)	859,764	0	0	0	0		305,277	306,261	5 00%	1,301	306,578	20,975,114	0	31

Total 11/2018 - 10/2019

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2018 - October 31, 2019		
Beginning Balance	$	(1,944,087)
Program Budget Nov 18-Oct 19	$	9,620,871
Projected Interest	$	(108,512)
Program Budget with Interest	$	7,568,271
Total Charges		**$7,568,271**

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual Environmental increase	$2,970,867	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,970,867	
Overall Annual Net Increase to Rates	$2,970,867	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/19 - sales and transportation	184,654,874	therms
Surcharge per therm	$0.0161	per therm
Total Environmental Surcharge	$0.0161	

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

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.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
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- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.
- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.
- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.
- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.
- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.
- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.
- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.
- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.
- ENGI 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.

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- 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 2001.

- 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.

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- 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

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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.

- 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.

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- The NHDES-approved subsurface soil and groundwater investigation program was initiated on September 26, 2011. The goal of this program was to delineate a Groundwater Management Zone for the site, and allow for the filing of a Groundwater Management Permit (GMP). Due to known asbestos in the off-site area to be investigated, ENGI submitted an "In-active Asbestos Disposal Site (ADS) Work Plan"; NHDES approved the asbestos work plan in October 2011. Soil boring and well installation work was performed between October and December 2011. An In-active ADS Site Completion Report was submitted to and accepted by NHDES on May 4, 2012. Groundwater sampling events were conducted in February and May 2012. A meeting to discuss the preliminary results of the Groundwater Management Zone (GMZ) investigation program with NHDES took place on August 16, 2012. It was agreed that two more rounds of groundwater sampling should occur before a delineation of the GMZ is considered.

- On November 27, 2012 and December 6, 2012, 8.25 feet and 10.83 feet of DNAPL appeared in MW-106, situated in the foot print of historical Holder #2. A weekly monitoring and removal plan was initiated at this time and is ongoing as of July 2013. To date, 109 gallons of DNAPL has been removed manually, in addition to the system removal discussed above.

- In January 2013, a Supplemental Investigation Report (SIR) and DNAPL Recovery System Pilot Test Progress report was submitted to NHDES reporting on additional investigation activities, including the installation of sixteen additional wells in 2011, and the May and September 2012 (second and third of three) rounds of sampling to define groundwater quality and hydrogeologic conditions at the site, so that the GMZ can be delineated. Additionally, the report includes information regarding DNAPL recovery system O&M activities and DNAPL recovery rates demonstrating that the system still effectively recovers DNAPL. A meeting with NHDES took place on March 22, 2013 to discuss these results and next steps.

- NHDES responded to the January 2013 submittal via letter dated May 21, 2013 accepting the SI Report and authorizing ENGI to proceed with the delineation of the GMZ in order to submit a Groundwater Management Permit (GMP) application, and the preparation of a revised Remedial Action Plan (RAP) for the terrestrial portion of the site.

- ENGI responded to the NHDES letter on June 19 with a schedule targeting December 31, 2013 for submittal of the GMP application and revised RAP.

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- In December 2013 ENGI submitted a request to revise the RAP. The purpose of the request was to summarize activities conducted since submittal of the 2013 Supplemental Investigation Report and to propose a revision to the approved RAP for the area on site known as "Holder # 2."

- The RAP submitted in 2005 selected asphalt capping in the area of Holder #2. The entire area of the Holder was not designated to be capped with asphalt. At the time of the preparation of the RAP, separate phase NAPL was not considered to be present in recoverable quantities in Holder #2. In order to address what appears to be a limited area and quantity of NAPL in a monitoring well in Holder #2, continued manual NAPL recovery from two additional wells in the Holder #2 area was proposed as part of the GMP monitoring program.

- In addition to the NAPL recovery activity, the area of asphalt capping was proposed to be expanded to include all of former Holder #2. This expansion of paving will also address the asbestos contaminated material (ACM) present in this area of the site. The asphalt cap detail presented in the proposed RAP revision will be modified (as necessary) to address the relevant solid waste regulations for ACM in soil.

- On June 4, 2014, the NHDES approved of the requested RAP revision and required that a RAP Summary Report, with the necessary engineering details for the selected remedies, be provided. ENGI plans to submit this RAP Summary Report by December 31, 2014.

- The GMP Application was submitted in March 2014. The GMP proposed a list of monitoring wells and analytical methods in order to monitor the Groundwater Management Zone.

- On June 5, 2014, the NHDES approved the GMP application. This Permit was issued for a period of 5 years requiring the monitoring of groundwater quality, assessing and recovering any free product found, and visually inspecting the Nashua River sediment cap area. During the first year of the Permit, monitoring events will be conducted in October 2014 and April 2015, and each successive April and October. Annual summary reports are submitted to the NHDES in January of each year.

- The first groundwater monitoring annual summary report was submitted to NHDES in February 2015, and included the groundwater data from the first GMP round of sampling on October 27, 2014.

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- ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. ENGI received comments from NHDES on December 15, 2016. NHDES altered the design to include an impermeable capping layer, and incorporation of standards in the Waste Management Bureau's Asbestos Disposal Site rules. As ENGI is planning to pave the Nashua property in 2018, the cap will be installed in conjunction with this capital project.

- During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste Remediation Bureau to include Per- and Polyfluoroalkyl Substances (PFAS) in one of their sampling rounds.

- The capping remedy was planned for 2018 in conjunction with an overall paving of the property, however a portion of the City's sewer pipe that transects the property collapsed in early February 2018 prompting the City to plan a lining upgrade to it during summer 2018. This event has caused the remedy construction to be pushed out to 2019.

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. DNAPL recovery is on-going. A Groundwater Management Permit was granted on June 5, 2014. A RAP Summary, involving the asphalt capping of the area over Holder #2 and continued groundwater monitoring, was submitted on April 2, 2015. A Monitoring Summary and Progress Report was submitted by ENGI on February 7, 2015. NHDES accepted the RAP Summary on April 10, 2015, with the provisions that ENGI submit the draft Activity and Use Restriction (AUR) and final engineering design plan for the cap by September 15, 2015. ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. NHDES responded to ENGI with their comments on December 15, 2016. Design for the engineered cap remedy is progressing, and when the design is completed it will be submitted to NHDES for approval. The cap construction and site paving are now planned for 2019 construction season.

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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 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.

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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.

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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. 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.

4. 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.

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- 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

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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.

- 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

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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, every April and October.

- 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.

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- 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.

- After meeting with the developer of the property directly downgradient of the site at the potential location of the barrier wall regarding potential impacts to the property in September/October 2011, access was obtained to conduct certain approved pre-design off-site investigation activities as recommended in the June 2010 RAP. The off-property investigations were substantially completed in December 2011. A meeting was held with NHDES in December 2011 to discuss the results. A Remedial Design Report for the off-site property is currently being finalized.

- On-site pre-design investigation activities were conducted during the spring and summer of 2012 including: additional groundwater quality monitoring, former gas holder foundation test pit excavations, supplemental LNAPL delineation, cyanide source investigation test pit excavations, cyanide delineation and source investigation monitoring well installation, and storm drain inspection.

- Further storm drain inspections occurred during July and August 2013. The remedial design and construction specifications report was drafted including a summary of the design investigation activities and findings. The remedial design includes the monitoring and practicable recovery of NAPL at strategic on-site and off-site locations, as well as excavation of subsurface structures with concurrent source removal if encountered. The Remedial Design Report also summarizes the results of cyanide source investigation and delineation work, with further source delineation work anticipated. In addition to routine Groundwater Management Permit (GMP) sampling and reporting, an application for GMP renewal was also submitted to NHDES during June 2014. The Remedial Design Report was submitted to NHDES on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions involving further remediation of historical Holder 3, and further investigation of the storm drain system beneath and downstream of the site. ENGI responded to NHDES' comments and requests on May 12, 2017.

- ENGI removed material from a tar-separator and other subsurface structures, installed three new monitoring wells and an extraction well on-site, prior to property paving in Fall 2017. Further removals from subsurface structures are planned for 2018.

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- During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste Remediation Bureau to include Per- and Polyfluoroalkyl Substances (PFAS) in one of their sampling rounds.

5. 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. The Remedial Design Report summarizing the activities for addressing on-site and off-site impacts was submitted on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions. ENGI addressed these concerns and implemented the remedial activities on-site and off-site in 2017.

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

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

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

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

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.

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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.

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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 modelling 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. On November 2, 2011 NHDES announced a Final Decision indicating that it did not concur with ENGI's recommended remedial approach and selecting the full removal option as the remedy for the site. On December 2, 2011, ENGI filed an appeal of the NHDES Final Decision with the New Hampshire Waste Management Council. In March 2012, ENGI attended the Pre-Conference Hearing with the Council related to the appeal. Hearings on the matter were scheduled for October 18 and November 15, 2012. On July 26, 2012, the Hearing Officer granted an Assented to Motion to Continue the hearing until a date after January 3, 2013.

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NO.

During the period of time the appeal was subject to the continuance, the company, the New Hampshire Department of Justice and NHDES engaged in settlement discussions on a confidential basis. At the conclusion of those negotiations, NHDES and the company agreed on a final remedy for the site, which was approved by NHDES. That approval allowed ENGI to withdraw its appeal as of December 19, 2012, and proceed with implementation of the remedy. The town of Gilford was briefed on the agreed-upon remedy concurrently with NHDES approval and ENGI's withdrawal of the appeal.

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.

The site was remediated in 2014-2015 construction seasons, and was restored to grass field by December 2015. NHDES approved the Notice of Activity and Use Restriction (AUR) in February 2017. In May 2017, ENGI received the post-construction groundwater monitoring permit, involving annual groundwater sampling.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: On December 10, 2012, ENGI submitted a Conceptual Remedial Design Report to NHDES describing the approach for full removal. NHDES approved this Conceptual RAP Addendum design on December 18, 2012, and ENGI withdrew their appeal before the New Hampshire Waste Management Council on December 19, 2012. A public meeting was held in the Town of Gilford to present the approved Conceptual Remedial Design on January 23, 2013. The pre-design investigation to confirm extent and depth of contamination commenced on February 20, 2013 and was completed first week in April 2013. A public meeting was held on September 25, 2013 to present the design to the Town. The Remedial Design Report was finalized and approved by NHDES in December 2013. Plans and Specifications were developed concurrently, and the bidding process commenced in

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September 2013 with a Request for Information to ten (10) prospective contractors. On October 28, six (6) contractors were selected to participate in the bidding for the construction, with bids due back on December 6, 2013. On January 9, 2014, three (3) of the bidders were interviewed and Charter Environmental of Boston, MA (the Contractor) was selected for the project. A public meeting took place on February 12, 2014 to further explain details of the anticipated construction and to introduce the project team to the community.

The Contractor mobilized to the site and began set-up in May 2014, with the first load of soil being hauled from the site on June 6, 2014. Construction began to remove tar-impacted soil on the south side of the site in the first season, with little to no impact to the surrounding community. In 2014, approximately 65% of the impacted soil was removed for treatment. On April 8, 2015, ENGI presented the results of the first season of construction at a Gilford Town Select Board meeting, and presented expectations for the second season to the community. Starting on April 13, 2015, the north side of the site was remediated, with the removal of all tar-impacted soil completed on August 3, 2015. The entire project was completed on September 24, 2015 with 2,662 truckloads hauling 93,502 tons of tar-impacted soil removed for thermal treatment. Some additional site restoration work was needed in October 2015 and another seeding in April 2016 to repair damage to the original restoration caused by a heavy rainstorm that occurred on September 30, 2015. Throughout the course of the project there was no disruption to the neighboring community and no safety incidents, logging 26,975 safe working hours. The project was completed within budget parameters.

The only activities on this site during the past year and ongoing are mowing and groundwater and surface sampling, per the new post-remedial Ground Water Management Permit received on May 10, 2017. During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste Remediation Bureau to include Per- and Polyfluoroalkyl Substances (PFAS) in one of their sampling rounds.

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.

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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.

With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated. The Company does not expect to pursue any insurance litigation.

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.

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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:

Concord MGP: 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

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LINE
NO.

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. ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling, along with further investigation of the brick tar sewer. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted in August 2013, in preparation for submittal of the Remedial Action Plan. This Supplement Data Collection Report was accepted by NHDES on October 24, 2013, and ENGI was authorized to prepare a RAP and Groundwater Management Permit (GMP) application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014.

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On June 16, 2013, wind during a thunderstorm caused a tree to fall on the northern side of the roof of the Holder House located on the former Concord MGP property. Damage to the slate roof and brick was sustained. In a letter dated February 24, 2014 NHDES stated that the holder structure "…serves as a physical barrier to prevent infiltration of precipitation into the foundation and thereby limits the amount of MGP byproducts that may be released to the environment." ENGI has evaluated damage to the roof and structure of the holder, and will be using this information to determine whether the holder will be restored or razed.

On March 31, 2015, ENGI submitted a proposed Remedial Action Plan involving removal of shallow soils displaying MGP-related residual impacts, investigation and remediation of remaining known subsurface structures, capping of components of the local storm water drainage system, site capping design, and continued monitoring of groundwater on the site. NHDES approved the RAP on May 29, 2015, with the condition that roof of the brick gas holder either be restored, or the holder be razed and the soils beneath it remediated. Soil vapor monitoring; soil vapor probe installation; and remedial design investigations including subsurface structure location and inspection, shallow tar-saturated soil delineation, and site storm drain system inspections, as approved by the RAP, were performed in December 2015. A Remedial Design Report (RDR) was submitted to NHDES on March 16, 2016 summarizing the above remedial design investigations. The remediation activities, required to be completed prior to site capping, include tar-impacted material removals and plugging of the on-site drain system, took place in 2017.

In early 2016 ENGI was approached by a commercial developer who was interested in purchasing the property and repurposing the holder house structure. Several site meetings and productive conversations took place with the developer. If the property is transferred, the purchaser's future use design would be taken into account when the final design of the engineered cap is being developed. This site developer has not contacted ENGI since the fall of 2017, and appears to have lost interest in the redevelopment project.

Concord Pond: ENGI has continued to monitor groundwater semi-annually 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, 2007 and 2012, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit.

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

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CONCORD FORMER MGP

LINE
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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. Contact was reconvened with the City in 2013, and adjustments to the original design were made to address outfall maintenance and access concerns of the City and NHDOT, respectively. The design was presented to the City on January 26, 2016. A rigorous schedule toward construction in late summer 2017 was agreed to by ENGI and the City in February 2016. The City did not meet an early deadline to determine and communicate details regarding access to their storm water system. Communication was again resumed in July 2016 by the City, however the City remained unresponsive to ENGI on implementation of the joint remedial design.

In March 2018, discussions with the new City Engineer took place and the City's engagement level has increased to come to a design solution on outfall maintenance. These discussions are frequent and ongoing.

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. During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste

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Remediation Bureau to include Per- and Polyfluoroalkyl Substances (PFAS) in one of their sampling rounds.

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. Based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river. ENGI met with NHDES on February 20, 2013 to discuss all sampling activities to date, summarized in an SIR Addendum Report, submitted in June 2013.

In May 2016, ENGI submitted a proposed plan for monitoring the near-bank sediments to the pond area in the Merrimack River. After discussions regarding frequency, duration of the Monitored Natural Recovery (MNR) program, and methodologies to be used in determining the contaminant trending in the river sediment, NHDES approved a revised MNR Plan in a letter dated July 2017. The 5-year sampling plan began in 2017 with the first of 5 annual samplings.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE:

Concord MGP: 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 Supplemental Data Collection report summarizing the investigation activities was accepted in October 2013, authorizing ENGI to prepare a RAP and GMP Application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed RAP, and NHDES approved the RAP with conditions. A Remedial Design Report, summarizing pre-design investigations, is to be provided to NHDES by the end of 2015.

Concord Pond: 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

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LINE
NO.

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 2010 and 2011. The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. The design was adjusted to accommodate the City's desire to simplify maintenance of the storm water system, however ENGI has received no response from the City after numerous attempts to begin the implementation

A renewal application for the Groundwater Management Permit was submitted on July 20, 2012, and the renewed permit was granted by NHDES on December 11, 2012. Groundwater and surface water monitoring continues under this permit every May and November.

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

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

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

2018 SUMMARY BY SITE

LINE NO.	SITE	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABLE EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL
1	Concord Pond	DEF056	-	130,096.96	-	-	8,604.02	138,700.98	[redacted]		127,356.38
2	Concord MGP	DEF077	2,124.00	57,893.99	-	-	10,983.48	71,001.47			57,559.09
3	Laconia/Liberty Hill	DEF086	-	30,546.25	-	-	3,493.97	34,040.22			34,040.22
4	Manchester MGP	DEF057	-	252,823.90	203,552.41	-	14,348.50	470,724.81			346,043.49
5	Nashua MGP	DEF054	-	60,516.43	-	-	961.72	61,478.15			15,523.24
6	General Expenses	DEF064	-	-	-	-	10,799.27	10,799.27			10,799.27
	Total Pool Activity		**2,124.00**	**531,877.53**	**534,001.53**	**-**	**49,190.96**	**786,744.90**	**-**	**(195,423.21)**	**591,321.69**

REDACTED

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
PROJECT DEF054

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
[redacted]											
2	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 0717					188.26	188.26			188.26
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12623		4,750.99				4,750.99			4,750.99
4	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12646		2,298.90				2,298.90			2,298.90
5	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12674		1,170.49				1,170.49			1,170.49
[redacted]											
7	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12700		1,390.91				1,390.91			1,390.91
8	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 1017					494.19	494.19			494.19
9	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12721		2,796.34				2,796.34			2,796.34
10	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12748		2,349.28				2,349.28			2,349.28
11	GZA GEOENVIRONMENTAL INC	751199		1,545.20				1,545.20			1,545.20
12	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12773		2,101.91				2,101.91			2,101.91
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12801		8,516.27				8,516.27			8,516.27
[redacted]											
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12827		6,201.08				6,201.08			6,201.08
[redacted]											
17	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12853		2,262.06				2,262.06			2,262.06
18	GZA GEOENVIRONMENTAL INC	754590		890.00				890.00			890.00
19	MARY CASEY - MILEAGE	JC10420					30.98	30.98			30.98
20	6/30/18 ACCRUAL			24,243.00				24,243.00			24,243.00
21								0.00			0.00
22								0.00			0.00
23	Environmental Staff Time						248.29	248.29			248.29
	Total Pool Activity		**-**	**60,516.43**	**-**	**-**	**961.72**	**61,478.15**	**-**	**(45,954.91)**	**15,523.24**

REDACTED

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
PROJECT DEF056

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	ANCHOR QEA LLC	52780		4,417.00				4,417.00			4,417.00
2	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 0717					2,800.40	2,800.40			2,800.40
3	CITY OF CONCORD	2017-50460144					1,020.00	1,020.00			1,020.00
4	GEI CONSULTANTS, INC.	3023173		10,873.95				10,873.95			10,873.95
5	ANCHOR QEA LLC	53274		2,732.28				2,732.28			2,732.28
6	GEI CONSULTANTS, INC.	3024117		7,153.51				7,153.51			7,153.51
7	ANCHOR QEA LLC	53684		3,267.25				3,267.25			3,267.25
8	GEI CONSULTANTS, INC.	3026036		2,449.16				2,449.16			2,449.16
9	CLEAN HARBORS	1002010768					918.07	918.07			918.07
10	ANCHOR QEA LLC	53983		1,874.00				1,874.00			1,874.00
11	CLEAN HARBORS	1002066623					277.20	277.20			277.20
12	GEI CONSULTANTS, INC.	3028085		2,441.58				2,441.58			2,441.58
13	MARY CASEY - MILEAGE	MILEAGE					69.84	69.84			69.84
14	ANCHOR QEA LLC	54929		18,327.36				18327.36			18,327.36
15	GEI CONSULTANTS, INC.	3027117		2,283.34				2283.34			2,283.34
16	NH DEPT OF ENVIRONMENTAL SERVICES	SQG SELFCERT CONCORD					270.00	270.00			270.00
17	GEI CONSULTANTS, INC.	3030430		5,924.48				5,924.48			5,924.48
18	ANCHOR QEA LLC	55234		7,664.89				7,664.89			7,664.89
19	[redacted]										
20											
21	ANCHOR QEA LLC	55820		1,948.00				1,948.00			1,948.00
22	GEI CONSULTANTS, INC.	3031191		11,010.86				11,010.86			11,010.86
23	GEI CONSULTANTS, INC.	3032434		2,195.36				2,195.36			2,195.36
24	ANCHOR QEA LLC	56204		984.75				984.75			984.75
25	GEI CONSULTANTS, INC.	3033558		1,481.46				1,481.46			1,481.46
26	ANCHOR QEA LLC	56882		8,053.75				8,053.75			8,053.75
27	GEI CONSULTANTS, INC.	3034922		3,509.84				3,509.84			3,509.84
28	CITY OF CONCORD	2018-50460122					1,020.00	1,020.00			1,020.00
29	[redacted]										
30	MARY CASEY - MILEAGE	MILEAGE					110.08	110.08			110.08
31	ANCHOR QEA LLC	54495		661.04				661.04			661.04
32	ANCHOR QEA LLC	57441		762.00				762.00			762.00
33	CLEAN HARBORS	1002347764					1,539.23	1,539.23			1,539.23
34	GEI CONSULTANTS, INC.	3036309		3,736.92				3,736.92			3,736.92
35	GEI CONSULTANTS, INC.	3037273		8,574.18				8,574.18			8,574.18
36	MARY CASEY - MILEAGE	MILEAGE					22.80	22.80			22.80
37	Environmental Staff Time			17,770.00			0.00	17,770.00			17,770.00
38	6/30/18 ACCRUAL						556.40	556.40			556.40
	Total Pool Activity		**0.00**	**130,096.96**	**0.00**	**0.00**	**8,604.02**	**138,700.98**	**0.00**	**(11,344.60)**	**127,356.38**

REDACTED

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
PROJECT DEF057

			1101	1102	1105	1106	1107		1108	1109	
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
1	CLEAN HARBORS	1002010900					530.46	530.46			530.46
2	CLEAN HARBORS	1002009730					277.20	277.20			277.20
[redacted]											
4	GZA GEOENVIRONMENTAL INC	744589		26,730.07				26,730.07			26,730.07
5	PLANT INSPECTORS FOR REMEDIATION ACTIVITIES				3,753.43			3,753.43			3,753.43
6	ESMI OF NH	1015191			90,828.00			90,828.00			90,828.00
7	MARY CASEY - MILEAGE	JC8825					53.93	53.93			53.93
8	MARY CASEY - MILEAGE	JC8825					166.72	166.72			166.72
9	CLEAN HARBORS	1002057075					8,308.52	8,308.52			8,308.52
10	T FORD COMPANY, INC	1806-1			90,930.00			90,930.00			90,930.00
11	CLEAN HARBORS	1002064356					277.20	277.20			277.20
12	ESMI OF NH	1015242			2,590.08			2,590.08			2,590.08
13	CLEAN HARBORS	1002139193					2,204.40	2,204.40			2,204.40
14	GZA GEOENVIRONMENTAL INC	750011		48,029.02				48,029.02			48,029.02
15	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 0118					839.09	839.09			839.09
[redacted]											
18	GZA GEOENVIRONMENTAL INC	749333		17,521.62				17,521.62			17,521.62
19	ESMI OF NH	1015428			10,368.40			10,368.40			10,368.40
20	ESMI OF NH	1015617			3,030.10			3,030.10			3,030.10
21	GZA GEOENVIRONMENTAL INC	753031		28,062.90				28,062.90			28,062.90
22	ESMI OF NH	1015717			2,052.40			2,052.40			2,052.40
23	GZA GEOENVIRONMENTAL INC	749019		78,038.61				78,038.61			78,038.61
[redacted]											
25	GZA GEOENVIRONMENTAL INC	755534		11,812.55				11,812.55			11,812.55
26	MARY CASEY - MILEAGE	JC10420					31.23	31.23			31.23
27	GZA GEOENVIRONMENTAL INC	757697		6,629.13				6,629.13			6,629.13
[redacted]											
29	6/30/18 ACCRUAL			36,000.00				36,000.00			36,000.00
30	Environmental Staff Time						$ 1,659.75	1,659.75			1,659.75
	Total Pool Activity		**0.00**	**252,823.90**	**203,552.41**	**0.00**	**14,348.50**	**470,724.81**	**0.00**	**(124,681.32)**	**346,043.49**

REDACTED

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
PROJECT DEF064

			1101	1102	1105	1106	1107		1108	1109	
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
1	ALLEGRA MARKETING PRINT MAIL	31130					180.00	180.00			180.00
2	MARY CASEY - MILEAGE	JC8825					49.69	49.69			49.69
3	MARY CASEY - MILEAGE	LABOR					50.37	50.37			50.37
4								0.00			0.00
5								0.00			0.00
6	Environmental Staff Time						10,519.21	10,519.21			10,519.21
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**10,799.27**	**10,799.27**	**0.00**	**0.00**	**10,799.27**

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
PROJECT DEF077

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CITY OF CONCORD	2017-50460144					1,020.00	1,020.00			1,020.00
3	CITY OF CONCORD GSD	410184001 0617					9.76	9.76			9.76
4	CITY OF CONCORD GSD	410184001 0717					9.76	9.76			9.76
5	ORR & RENO, P.A.	108290	2,124.00					2,124.00			2,124.00
6	CITY OF CONCORD GSD	410184001 0817					9.62	9.62			9.62
7	CLEAN HARBORS	1002010746					2,645.39	2,645.39			2,645.39
8	CLEAN HARBORS	1002010768					513.03	513.03			513.03
9	GZA GEOENVIRONMENTAL INC	744553		16,727.48				16,727.48			16,727.48
10	GZA GEOENVIRONMENTAL INC	744590		3,452.78				3,452.78			3,452.78
11	JOE GAUCI LANDSCAPING LLC	2017-8-3576					1,438.00	1,438.00			1,438.00
12	CITY OF CONCORD GSD	410184001 0917					9.76	9.76			9.76
13	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 1017					141.21	141.21			141.21
14	JOE GAUCI LANDSCAPING LLC	2017-9-3576					474.00	474.00			474.00
15	GZA GEOENVIRONMENTAL INC	736983		354.55				354.55			354.55
16	MARY CASEY - MILEAGE	JC8825					70.81	70.81			70.81
17	JOE GAUCI LANDSCAPING LLC	3576					509.00	509.00			509.00
18	NH DEPT OF ENVIRONMENTAL SERVICES	SQG SELFCERT					270.00	270.00			270.00
19	GZA GEOENVIRONMENTAL INC	748974		2,107.50				2,107.50			2,107.50
20	CITY OF CONCORD	410184-001					19.52	19.52			19.52
21	GZA GEOENVIRONMENTAL INC	750012		2,320.30				2,320.30			2,320.30
22	GZA GEOENVIRONMENTAL INC	748973		11,791.42				11,791.42			11,791.42
23	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 0118					70.59	70.59			70.59
[redacted]											
26	CITY OF CONCORD GSD	410184-001 1217					29.43	29.43			29.43
27	CITY OF CONCORD GSD	410184-001 0218					29.58	29.58			29.58
28	GZA GEOENVIRONMENTAL INC	753234		4,677.00				4,677.00			4,677.00
29	GZA GEOENVIRONMENTAL INC	749326		6,936.38				6,936.38			6,936.38
30	CITY OF CONCORD	2018-50460122					1,020.00	1,020.00			1,020.00
[redacted]											
32	GZA GEOENVIRONMENTAL INC	755027		1,060.75				1,060.75			1,060.75
33	JOE GAUCI LANDSCAPING LLC	2018-5-3576					597.00	597.00			597.00
34	CLEAN HARBORS	1002347764					1,833.59	1,833.59			1,833.59
35	GZA GEOENVIRONMENTAL INC	757698		4,965.83				4,965.83			4,965.83
36	6/30/18 ACCRUAL			3,500.00				3,500.00			3,500.00
37	Environmental Staff Time						263.43	263.43			263.43
	Total Pool Activity		**2,124.00**	**57,893.99**	**0.00**	**0.00**	**10,983.48**	**71,001.47**	**0.00**	**(13,442.38)**	**57,559.09**

REDACTED

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL - REMEDIATION
PROJECT DEF086

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUB-TOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	MULLER'S LAWN & LANDSCAPING, LLC	4403					800.00	800.00			800.00
2	GEI CONSULTANTS, INC.	3027116		25,493.60				25,493.60			25,493.60
3	CLEAN HARBORS	1002031388					519.20	519.20			519.20
4	MULLER'S LAWN & LANDSCAPING, LLC	4489					800.00	800.00			800.00
5	GEI CONSULTANTS, INC.	3028084		3,769.44				3,769.44			3,769.44
6	NH DEPT OF ENVIRONMENTAL SERVICES	SQG SELFCERT LIB HIL					270.00	270.00			270.00
7	GEI CONSULTANTS, INC.	3030427		1,283.21				1,283.21			1,283.21
8	BLUE CHIP FILMS LLC	1438					675.00	675.00			675.00
9	BLUE CHIP FILMS LLC	1468					300.00	300.00			300.00
10								-			-
11								-			-
23	Environmental Staff Time						129.77	129.77			129.77
	Total Pool Activity		0.00	30,546.25	0.00	0.00	3,493.97	34,040.22			34,040.22

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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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
Tariff page 95

Concord Pond

DEF056

	(thru 9/99) pool #1 #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 #12	(9/11 9/12) pool #13	(9/12 6/13) pool #14	(7/13 6/14) pool #15	(7/14 6/15) pool #16	(7/15 6/16) pool #17	(7/16 6/17) pool #18	(7/17 6/18) pool #19	subtotal
1 Remediation costs (i.o. 500061)	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
Remediation costs (i.o. 500005)	-	-																-
A Subtotal - remediation costs	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
																		-
Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,204,671)
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	(1,836,941)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,026,872)
																		-
A-B Total net expenses to recover	3,583,912	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	216,743	81,238	59,069	32,324	78,235	34,590	88,148	127,356	5,051,537
																		-
																		-
Surcharge revenue:																		-
Act June 1998 - October 1998	(54,889)	-																(54,889)
Act November 1998 - October 1999	(538,143)	-																(538,143)
Act November 1999 - October 2000	(760,871)	-																(760,871)
Act November 2000 - October 2001	(626,614)	(13,925)																(640,539)
Act November 2001 - October 2002	(600,600)	(24,514)																(625,114)
Act November 2002 - October 2003	(592,678)	(15,197)																(607,874)
Act November 2003 - October 2004	(291,340)	(14,567)																(305,907)
Act November 2004- October 2005	(56,719)	(14,180)	(14,180)															(85,078)
Act November 2005- October 2006	-	(6,875)	(6,875)															(13,750)
Act November 2006- October 2007	-	-	-	-	(14,091)													(14,091)
Act November 2007- October 2008																		-
Act November 2012- October 2013										(5,002)	(5,002)							(10,003)
Act November 2013- October 2014										(12,749)	(12,749)							(25,497)
Act Nov 2009-Oct 2010 Base Rate Rev										($4,423)								(4,423)
Act Nov 2010-Oct 2011 Base Rate Rev										($32,310)								(32,310)
Act Nov 2011-Oct 2012 Base Rate Rev										($28,448)								(28,448)
Act Nov 2012-Oct 2013 Base Rate Rev										($2,143)	($2,143)							(4,286)
Act Nov 2013-Oct 2014 Base Rate Rev																		-
Act Nov 2014-Oct 2015 Base Rate Rev																		
AES collections			(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(220,792)
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	-	-	-	-	-	-	-	-	-	-	
																		0
																		-
C Surcharge Subtotal	(3,524,326)	(50,710)	(9,559)	39,108	34,729	104,437	234,166	(12,904)	(13,145)	(98,295)	(33,631)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(3,995,526)
D Net balance to be recovered (A-B+C)	59,586	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	47,629	47,608	45,345	18,376	64,062	20,185	73,484	112,498	1,056,012
E Allocation of Litigated Recovery			-		-		(329,540)	(102,675)	(123,791)	(47,228)	-	-	-	-	-	-	-	(603,234)
Surcharge calculation																		
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	6,801	12,956	7,875	36,607	14,417.84	62,986.49	112,498.35	254,142
remaining life	-	-	24	36	48	60	72	84	84	84	12	24	36	48	60	72	84	
one year	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
Required annual increase in rates:																		
smaller of D or F	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
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	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Laconia & Liberty Hill

																DEF086	
			i.o. no. 500005														
			(thru 9/01) pool #1 #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	(9/11 9/12) pool #11	(9/12 6/13) pool #12	(7/13 6/14) pool #13	(7/14 6/15) pool #14	(7/15 6/16) pool #15	(7/16 6/17) pool #16	(7/17 6/18) pool #17	subtotal
1	1	Remediation costs (i.o. 500061)	-	-									[redacted]					
2		Remediation costs (i.o. 500005)	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
3	A	Subtotal - remediation costs	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
4																		
5		Cash recoveries (i.o. 500061)	-	-	-	-	-	-										
6		Cash recoveries (i.o. 500004)	-	-	-	-	-	-										
7		Recovery costs (i.o. 500004)	-			11,643	21,729	-	-									
8		Transfer Credit from Gas Restructurin				-	-	-										
9	B	Subtotal - net recoveries	-	-	-	11,643	21,729	-	-	-	-	-						
10																		
11	A-B	Total net expenses to recover	5,241,032	9,702	2,330,555	2,100,842	449,954	607,876	262,678	210,532	269,281	642,986						
12																		
13																		
14		Surcharge revenue:																
15	Act	June 1998 - October 1998	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
16	Act	November 1998 - October 1999	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
17	Act	November 1999 - October 2000	(151,933)	-	-		-	-	-	-	-	-	-	-	-	-	-	(151,933)
18	Act	November 2000 - October 2001	(696,237)	-	-		-	-	-	-	-	-	-	-	-	-	-	(696,237)
19	Act	November 2001 - October 2002	(796,714)	-	-		-	-	-	-	-	-	-	-	-	-	-	(796,714)
20	Act	November 2002 - October 2003	(805,434)	-	-		-	-	-	-	-	-	-	-	-	-	-	(805,434)
21	Act	November 2003 - October 2004	(699,215)															(699,215)
22	Act	November 2004- October 2005	(652,264)															(652,264)
23	Act	November 2005- October 2006	(691,159)	-	-		-	-	-	-	-	-	-	-	-	-	-	(691,159)
24	Act	November 2006- October 2007	(648,174)	-	(309,996)													(958,171)
25	Act	November 2007- October 2008																-
26	Act	November 2012- October 2013									(20,006)							(20,006)
27	Act	November 2013- October 2014									(25,497)	(76,491)						(101,988)
28	Act	Nov 2009-Oct 2010 Base Rate Rev								($4,296)								(4,296)
29	Act	Nov 2010-Oct 2011 Base Rate Rev								($31,384)								(31,384)
30	Act	Nov 2011-Oct 2012 Base Rate Rev								($27,632)								(27,632)
31	Act	Nov 2012-Oct 2013 Base Rate Rev								$0	($14,208)							(14,208)
32	Act	Nov 2013-Oct 2014 Base Rate Rev									(28,433)	(28,433)	(28,433)					(85,298)
33	Act	Nov 2014-Oct 2015 Base Rate Rev									(21,909)	(21,909)	(21,909)	(21,909)	-	-	-	(87,637)
34		AES collections																-
35		Gas Street overcollection																-
36		Prior Period Pool under/overcollection	21,391	111,336	121,038	2,141,596	4,242,438		-	-	(89,606)	-	-	-	-	-	-	
37																		
38																		
39	C	Surcharge Subtotal	(5,119,739)	111,336	(188,958)	2,141,596	4,242,438	-	-	(63,313)	(199,659)	(126,833)	(50,342)	(21,909)	-	-	-	(5,823,577)
40																		
41																		
42	D	Net balance to be recovered (A-B+C)	121,293	121,038	2,141,596	4,242,438	4,692,393	607,876	262,678	147,219	69,622	516,153	[redacted]					
43																		
44	E	Allocation of Litigated Recovery					(4,692,393)	(607,876)	(262,678)	(236,825)	-	-						
45																		
46		Surcharge calculation																
47		Unrecovered costs (D+E)	-	-			-	-	-	-	9,946	147,472.25						
48		remaining life	-	36	48	60	72	84	84	48	12	24						
49		one year	-	12	12	12	12	12	12	12	12	12						
50	F	amortization	-	-	-	-	-	-	-	-	9,946	73,736						
51																		
52		Required annual increase in rates:																
53		smaller of D or F	-	-	-		-	-	-	-	9,946	73,736	[redacted]					
54																		
55		forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																		
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0004	[redacted]					

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Manchester

DEF057

			(9/00 9/03) pool #1 #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 #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	(7/17 6/18) pool #18	subtotal
								Incl. Audit Corr											
1	1	Remediation costs (i.o. 500061)	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	10,598,402
2		Remediation costs (i.o. 500005)	825,092																825,092
3	A	Subtotal - remediation costs	825,092	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	11,423,494
4																			
5		Cash recoveries (i.o. 500061)	-			(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(2,753,952)
6		Cash recoveries (i.o. 500004)	-																-
7		Recovery costs (i.o. 500004)	-	1,242,326			2,546	-											1,244,872
8		Transfer Credit from Gas Restructurin					-	-											-
9	B	Subtotal - net recoveries	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(1,509,080)
10																			
11	A-B	Total net expenses to recover	825,092	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,589	442,298	(188,619)	61,210	75,440	22,690	50,523	346,043	9,914,414
12																			-
13																			-
14		Surcharge revenue:																	-
15	Act	June 1998 - October 1998	-	-															-
16	Act	November 1998 - October 1999	-	-															-
17	Act	November 1999 - October 2000	-	-															-
18	Act	November 2000 - October 2001	-	-															-
19	Act	November 2001 - October 2002	(73,543)	-															(73,543)
20	Act	November 2002 - October 2003	(75,984)	-															(75,984)
21	Act	November 2003 - October 2004	(138,576)	-															(138,576)
22	Act	November 2004- October 2005	(113,437)	(212,695)	-			-	-	-	-	-	-	-	-	-	-	-	(326,132)
23	Act	November 2005- October 2006	(96,247)	(206,243)	(261,242)			-	-	-	-	-	-	-	-	-	-	-	(563,732)
24	Act	November 2006- October 2007	(126,817)	(211,361)	(281,815)	(42,272)													(662,265)
25	Act	November 2007- October 2008																	-
26	Act	November 2012- October 2013										(40,012)							(40,012)
27	Act	November 2013- October 2014										(50,994)							(50,994)
28	Act	Nov 2009-Oct 2010 Base Rate Rev									-								-
29	Act	Nov 2010-Oct 2011 Base Rate Rev									-								-
30	Act	Nov 2011-Oct 2012 Base Rate Rev									-								-
31	Act	Nov 2012-Oct 2013 Base Rate Rev									-	(23,337)							(23,337)
32	Act	Nov 2013-Oct 2014 Base Rate Rev																	-
33	Act	Nov 2014-Oct 2015 Base Rate Rev																	
34		AES collections																	-
35		Gas Street overcollection																	-
36		Prior Period Pool under/overcollection	394,600	276,881	1,224,246	2,671,037	2,958,927	3,302,330	-	-	-								
37																			
38																			
39	C	Surcharge Subtotal	(230,004)	(353,418)	681,189	2,628,765	2,958,927	3,302,330	-	-	-	(114,343)	-	-	-	-	-	-	(1,954,576)
40																			
41																			
42	D	Net balance to be recovered (A-B+C)	595,088	1,224,246	2,671,037	2,958,927	3,302,330	6,562,539	312,185	328,678	137,589	327,955	(188,619)	61,210	75,440	22,690	50,523	346,043	7,959,838
43																			
44	E	Allocation of Litigated Recovery		-	-			(6,562,539)	(312,185)	(328,678)	(91,770)	-	-	-	-	-	-	-	(7,295,172)
45																			
46		Surcharge calculation																	
47		Unrecovered costs (D+E)	-	-	-	-		-	-	-	-	46,851	(53,891)	26,233	43,108	16,207	43,305	346,043	467,856
48		remaining life	-	24	36	48	60	70	84	84	12	12	24	36	48	60	72	84	
49		one year	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F	amortization	-	-	-	-	-	-	-	-	-	46 851	(26 946)	8 744	10 777	3 241	7 218	49 435	
51																			
52		Required annual increase in rates:																	
53		smaller of D or F	-	-	-	-		-	-	-	-	46,851	(26,946)	8,744	10,777	3,241	7,218	49,435	99,320
54																			
55		forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																			
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003	$0.0005

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Nashua																
					Corrected per 2/08 Audit											**DEF054**	
	(9/00 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)**	**(9/11 9/12)**	**(9/12 6/13)**	**(7/13 6/14)**	**(7/14 6/15)**	**(7/15 6/16)**	**(7/16 6/17)**	**(7/17 6/18)**	
	pool #1 #3	**pool #4**	**pool #5**	**pool #6**	**pool #7**	**pool #8**	**pool #9**	**pool #10**	**pool #11**	**pool #12**	**pool #13**	**pool #14**	**pool #15**	**pool #16**	**pool #17**	**pool #18**	**subtotal**
1 Remediation costs (i.o. 500061)	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	1,620,044
Remediation costs (i.o. 500005)	1,771,567																1,771,567
A Subtotal - remediation costs	1,771,567	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	3,391,611
																	-
Cash recoveries (i.o. 500061)	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(566,063)
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)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(547,675)
																	-
A-B Total net expenses to recover	1,771,567	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,351	396,411	(80,241)	35,950	65,217	62,435	85,314	15,523	2,843,936
Surcharge revenue:																	
Act June 1998 - October 1998	-	-															-
Act November 1998 - October 1999	-	-															-
Act November 1999 - October 2000	-	-															-
Act November 2000 - October 2001	-	-															-
Act November 2001 - October 2002	(183,857)	-															(183,857)
Act November 2002 - October 2003	(243,150)	-															(243,150)
Act November 2003 - October 2004	(247,639)	-															(247,639)
Act November 2004- October 2005	(241,054)	-															(241,054)
Act November 2005- October 2006	(247,492)	-	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(274,991)
Act November 2006- October 2007	(253,633)	-	(28,181)	-													(281,815)
Act November 2007- October 2008																	-
Act November 2012- October 2013										(40,012)							(40,012)
Act November 2013- October 2014										(38,246)							(38,246)
Act Nov 2009-Oct 2010 Base Rate Rev									-								-
Act Nov 2010-Oct 2011 Base Rate Rev									-								-
Act Nov 2011-Oct 2012 Base Rate Rev									-								-
Act Nov 2012-Oct 2013 Base Rate Rev									-	(20,916)							(20,916)
Act Nov 2013-Oct 2014 Base Rate Rev																	-
Act Nov 2014-Oct 2015 Base Rate Rev																	
AES collections																	-
Gas Street overcollection																	-
Prior Period Pool under/overcollection	669,664	543,205	554,046	704,732	714,955	733,479	-	-	-	6,224	-	-	-	-	-	-	
C Surcharge Subtotal	(747,161)	543,205	498,365	704,732	714,955	733,479	-	-	-	(92,950)	-	-	-	-	-	-	(1,571,680)
D Net balance to be recovered (A-B+C)	1,024,405	554,046	704,732	714,955	733,479	830,669	16,289	98,975	33,351	303,461	(80,241)	35,950	65,217	62,435	85,314	15,523	1,272,256
E Allocation of Litigated Recovery	-	-	-	-	-	(830,669)	(16,289)	(98,975)	(27,127)	-	-	-	-	-	-	-	(973,061)
Surcharge calculation																	
Unrecovered costs (D+E)	-	-	-	-		-	-	-		43,352	(22,926)	15,407	37,267	44,596	73,126	15,523	206,345
remaining life	12	24	36	48	60	72	84	84	72	12	24	36	48	60	72	84	
one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	43 352	(11 463)	5 136	9 317	8 919	12 188	2 218	
Required annual increase in rates:																	
smaller of D or F	-	-	-	-		-	-	-	-	43,352	(11,463)	5,136	9,317	8,919	12,188	2,218	69,665
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0004

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		Dover												
													DEF059	
		(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	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/17 6/18) pool #12	subtotal
1	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:													
Act	June 1998 - October 1998	-												-
Act	November 1998 - October 1999	-												-
Act	November 1999 - October 2000	-												-
Act	November 2000 - October 2001	-												-
Act	November 2001 - October 2002	-												-
Act	November 2002 - October 2003	-												-
Act	November 2003 - October 2004	(29,134)												(29,134)
Act	November 2004- October 2005	(28,359)												(28,359)
Act	November 2005- October 2006	(27,499)	-			-	-	-	-	-	-	-	-	(27,499)
Act	November 2006- October 2007	(28,181)	-	-										(28,181)
Act	November 2007- October 2008													-
Act	November 2012- October 2013													-
Act	November 2013- October 2014													-
Act	Nov 2009-Oct 2010 Base Rate Rev													-
Act	Nov 2010-Oct 2011 Base Rate Rev													-
Act	Nov 2011-Oct 2012 Base Rate Rev													-
Act	Nov 2012-Oct 2013 Base Rate Rev													-
Act	Nov 2013-Oct 2014 Base Rate Rev													-
Act	Nov 2014-Oct 2015 Base Rate Rev													
	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													
	Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	-	-	-
	remaining life	24	36	48	60	72	84	84	84	84	84	84	84	
	one year	12	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-	-	-	-	-	-	
	Required annual increase in rates:													
	smaller of D or F	-	-	-		-	-	-	-	-	-	-	-	-
	forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
	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	$0.0000

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Keene												
												DEF055	
	(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**	**(9/11 9/12) pool #9**	**(9/12 6/13) pool #10**	**(7/13 6/14) pool #11**	**(7/14 6/15) pool #12**	**subtotal**
1 Remediation costs (i.o. 500061)	-										[redacted]		
Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
A Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
Cash recoveries (i.o. 500061)	-												
Cash recoveries (i.o. 500004)	-												
Recovery costs (i.o. 500004)			18,831	823	-	-	-	-					
Transfer Credit from Gas Restructurin				-	-	-							
B Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-			
A-B Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400			
													-
													-
Surcharge revenue:													-
Act June 1998 - October 1998	-												-
Act November 1998 - October 1999	-												-
Act November 1999 - October 2000	-												-
Act November 2000 - October 2001	-												-
Act November 2001 - October 2002	-												-
Act November 2002 - October 2003	-												-
Act November 2003 - October 2004	-												-
Act November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
Act November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
Act November 2006- October 2007	-	-	(14,091)										(14,091)
Act November 2007- October 2008													-
Act November 2012- October 2013													-
Act November 2013- October 2014													-
Act Nov 2009-Oct 2010 Base Rate Rev													-
Act Nov 2010-Oct 2011 Base Rate Rev													-
Act Nov 2011-Oct 2012 Base Rate Rev													-
Act Nov 2012-Oct 2013 Base Rate Rev													-
Act Nov 2013-Oct 2014 Base Rate Rev													-
Act Nov 2014-Oct 2015 Base Rate Rev													
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	-	-	488	1,400	[redacted]		
E Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-			
Surcharge calculation													
Unrecovered costs (D+E)	-	-	-			-	-	-	70	400			
remaining life	24	36	48	60	72	84	84	84	12	24			
one year	12	12	12	12	12	12	12	12	12	12			
F amortization	-	-	-	-	-	-	-	-	70	200			
Required annual increase in rates:													
smaller of D or F	-	-	-			-	-	-	70	200	[redacted]		
forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Concord														
		Corrected per 1/24/07 Audit	Corrected per 2/08 Audit											DEF077	
	(9/03 9/05) pool #1 & #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	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	(7/15 6/16) pool #13	(7/16 6/17) pool #14	(7/17 6/18) pool #15	subtotal
1 Remediation costs (i.o. 500061)	-												[redacted]	[redacted]	[redacted]
Remediation costs (i.o. 500005)	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749	[redacted]	[redacted]	[redacted]
A Subtotal - remediation costs	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749	[redacted]	[redacted]	[redacted]
Cash recoveries (i.o. 500061)	-	(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)	[redacted]	[redacted]	[redacted]
Cash recoveries (i.o. 500004)	-												[redacted]	[redacted]	[redacted]
Recovery costs (i.o. 500004)				1,432	(1,007)								[redacted]	[redacted]	[redacted]
Transfer Credit from Gas Restructurin		-											[redacted]	[redacted]	[redacted]
B Subtotal - net recoveries	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)	[redacted]	[redacted]	[redacted]
A-B Total net expenses to recover	243,123	22,106	61,665	(3,163)	92,679	46,190	168,338	257,528	45,384	123,355	163,783	95,553	[redacted]	[redacted]	[redacted]
															-
															-
Surcharge revenue:															-
Act June 1998 - October 1998	-														-
Act November 1998 - October 1999	-														-
Act November 1999 - October 2000	-														-
Act November 2000 - October 2001	-														-
Act November 2001 - October 2002	-														-
Act November 2002 - October 2003	-														-
Act November 2003 - October 2004	-														-
Act November 2004- October 2005															-
Act November 2005- October 2006	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(27,499)
Act November 2006- October 2007	(28,181)	-													(28,181)
Act November 2007- October 2008															-
Act November 2012- October 2013							(20,006)	(20,006)							(40,012)
Act November 2013- October 2014							(12,749)	(25,497)							(38,246)
Act Nov 2009-Oct 2010 Base Rate Rev							($1,891)								(1,891)
Act Nov 2010-Oct 2011 Base Rate Rev							($13,816)								(13,816)
Act Nov 2011-Oct 2012 Base Rate Rev							($12,164)								(12,164)
Act Nov 2012-Oct 2013 Base Rate Rev							($6,794)	($6,794)							(13,588)
Act Nov 2013-Oct 2014 Base Rate Rev															-
Act Nov 2014-Oct 2015 Base Rate Rev															
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	-	-	(67,420)	(52,297)	-	-	-	-	-	-	(175,398)
D Net balance to be recovered (A-B+C)	209,633	209,549	271,214	268,051	92,679	46,190	100,919	205,231	45,384	123,355	163,783	95,553	[redacted]	[redacted]	[redacted]
E Allocation of Litigated Recovery	-	-	-	(268,051)	(92,679)	(46,190)	(13,905)	-	-	-	-	-	[redacted]	[redacted]	[redacted]
Surcharge calculation													[redacted]	[redacted]	[redacted]
Unrecovered costs (D+E)	-	-		-	-	-	-	29,319	12,967	52,866	93,590	68,252	[redacted]	[redacted]	[redacted]
remaining life	84	60		72	84	84	12	12	24	36	48	60	[redacted]	[redacted]	[redacted]
one year	24	12		12	12	12	12	12	12	12	12	12	[redacted]	[redacted]	[redacted]
F amortization	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650	[redacted]	[redacted]	[redacted]
Required annual increase in rates:															
smaller of D or F	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650	[redacted]	[redacted]	[redacted]
forecasted therm sales	369,309,748	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0001	$0.0001	$0.0001	[redacted]	[redacted]	[redacted]

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Line		General																
			Corrected per 1/24/07 Audit												DEF064			2018 MGP Remediation
		(9/02 9/05) pool #1 #3	(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	(9/11 9/12) pool #10	(9/12 6/13) pool #11	(7/13 6/14) pool #12	(7/14 6/15) pool #13	(7/15 6/16) pool #14	(7/16 6/17) pool #15	(7/17 6/18) pool #16	subtotal		subtotal
1	1 Remediation costs (i.o. 500061)	-														-		[redacted]
2	Remediation costs (i.o. 500005)	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
3	A Subtotal - remediation costs	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
4																		
5	Cash recoveries (i.o. 500061)	-		-	-	-										-		
6	Cash recoveries (i.o. 500004)	-														-		
7	Recovery costs (i.o. 500004)		290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	322,270		
8	Transfer Credit from Gas Restructuring	(3,331)	-													(3,331)		
9	B Subtotal - net recoveries	(3,331)	290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	318,939		
10																		
11	A-B Total net expenses to recover	746,908	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	73,846	13,139	(7,638)	11,879	6,547	10,799	1,218,366		
12																		
13																		-
14	Surcharge revenue:																	
15	Act June 1998 - October 1998	-														-		(54,889)
16	Act November 1998 - October 1999	-														-		(538,143)
17	Act November 1999 - October 2000	-														-		(912,804)
18	Act November 2000 - October 2001	-														-		(1,336,776)
19	Act November 2001 - October 2002	-														-		(1,679,228)
20	Act November 2002 - October 2003	-														-		(1,732,442)
21	Act November 2003 - October 2004	(8,265)														(8,265)		(1,428,735)
22	Act November 2004- October 2005	(70,898)														(70,898)		(1,403,787)
23	Act November 2005- October 2006	(96,247)			-	-	-	-	-	-	-	-	-	-	-	(96,247)		(1,694,877)
24	Act November 2006- October 2007		(49,318)													(49,318)		(2,036,113)
25	Act November 2007- October 2008															-		-
26	Act November 2012- October 2013							(5,002)	(5,002)							(10,003)		(160,048)
27	Act November 2013- October 2014							(12,749)	(12,749)	(12,749)						(38,246)		(293,217)
28	Act Nov 2009-Oct 2010 Base Rate Rev															-		(10,611)
29	Act Nov 2010-Oct 2011 Base Rate Rev															-		(77,509)
30	Act Nov 2011-Oct 2012 Base Rate Rev															-		(68,244)
31	Act Nov 2012-Oct 2013 Base Rate Rev															-		(76,335)
32	Act Nov 2013-Oct 2014 Base Rate Rev																	(85,298)
33	Act Nov 2014-Oct 2015 Base Rate Rev																	(87,637)
34	AES collections	-														-		(220,792)
35	Gas Street overcollection															-		(23,511)
36	Prior Period Pool under/overcollection	296,594	457,429	732,622	786,465	-	-	-	-	-	-	-	-	-	-			
37																		
38																		
39	C Surcharge Subtotal	15,503	408,111	732,622	786,465	-	-	(17,750)	(17,750)	(12,749)	-	-	-	-	-	(272,977)		(13,920,997)
40																		
41																		
42	D Net balance to be recovered (A-B+C)	762,410	732,622	786,465	621,477	(2,931)	4,199	51,536	61,217	61,098	13,139	(7,638)	11,879	6,547	10,799	945,390	3,595,226	[redacted]
43																	-	
44	E Allocation of Litigated Recovery	-	-	-	(621,477)	2,931	(4,199)	(11,582)	-	-	-	-	-	-	-	(634,326)	(428,437)	
45																	-	
46	Surcharge calculation																-	
47	Unrecovered costs (D+E)	-	-		-	-	-	-	8,745	17,456	5,631	(4,364)	8,485	5,611	10,799	52,364	2,150,415	
48	remaining life	84	60	72	84	84	84	12	12	24	36	48	60	72	84			
49	one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12			
50	F amortization	-	-	-	-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543			
51																		
52	Required annual increase in rates:																	
53	smaller of D or F	-	-		-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543	22,434	584,652	
54																		
55	forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874		**184,654,874**
56																		
57	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	$0.0000	$0.0000	$0.0001		**$0.0161**

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Expense and Collection Summary per Year

Line			(thru 9/98)	(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)	(9/11 9/12)	(7/13 6/14)	(7/14 6/15)	(7/15 6/16)	(7/16 6/17)	(7/17 6/18)	Total
1	1	Remediation costs (i.o. 500061)	5,420,852	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,515	993,434	196,611	312,039	220,344	256,871	670,904	[redacted]
2		Remediation costs (i.o. 500005)	1,027,747	-	-	-	181,066	10,165	16,308	2,444,366	2,229,625	255,263	658,324	316,280	459,550	651,906	1,801,404	7,975,914	3,307,910	260,380	115,841	
3	A	Subtotal - remediation costs	6,448,599	129,002	-	-	181,066	416,637	2,252,990	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,146,065	1,645,340	1,998,015	8,287,953	3,528,254	517,250	786,745	
4																						
5		Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(79,446)	(121,889)	(119,826)	(53,116)	(195,423)	
6		Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	-	-	
7		Recovery costs (i.o. 500004)	623,784	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	(14,068)	2,500,000	2,475,750	-	-	-	
8		Transfer Credit from Gas Restructuring	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
9	B	Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	-	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	2,420,554	2,353,861	(119,826)	(53,116)	(195,423)	
10																						
11	A-B	Total net expenses to recover	4,611,659	95,798	-	-	181,066	1,273,932	2,379,412	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	835,839	1,526,211	4,418,569.29	10,641,813.86	3,408,427.63	464,499.00	591,686.20	
12																						
13																						
14		Surcharge revenue:																				
15	Act	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
16	Act	November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
17	Act	November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
18	Act	November 2000 - October 2001	(779,786)	(13,925)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(793,711)
19	Act	November 2001 - October 2002	(759,943)	(24,514)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(784,457)
20	Act	November 2002 - October 2003	(744,646)	(15,197)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(759,843)
21	Act	November 2003 - October 2004	(422,442)	(14,567)	-	-	(29,134)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(466,143)
22	Act	November 2004- October 2005	(184,336)	(14,180)	-	-	(28,359)	(226,875)	-	-	-	-	-	-	-	-	-	-	-	-	-	(453,749)
23	Act	November 2005- October 2006	(141,176)	(6,875)	-	-	(27,499)	(213,118)	(288,741)	-	-	-	-	-	-	-	-	-	-	-	-	(677,409)
24	Act	November 2006- October 2007	-	-	-	-	(28,181)	(211,361)	(309,996)	(429,768)	-	-	-	-	-	-	-	-	-	-	-	(979,307)
25	Act	November 2007- October 2008													-	-	-	-	-	-	-	-
26	Act	November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	-	-	(160,048)
27	Act	November 2013- October 2014													(38,246)	(165,731)	-	-	-	-	-	(203,977)
28	Act	Nov 2009-Oct 2010 Base Rate Rev													(10,611)	-	-	-	-	-	-	(10,611)
29	Act	Nov 2010-Oct 2011 Base Rate Rev													(77,509)	-	-	-	-	-	-	(77,509)
30	Act	Nov 2011-Oct 2012 Base Rate Rev													(68,244)	-	-	-	-	-	-	(68,244)
31	Act	Nov 2012-Oct 2013 Base Rate Rev													(8,937)	(67,398)	-	-	-	-	-	(76,335)
32	Act	Nov 2013-Oct 2014 Base Rate Rev													-	(28,433)	(28,433)	-	-	-	-	(56,865)
33	Act	Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	(21,909)	(21,909)	-	-	-	(65,728)
34		AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(207,067)
35		Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
36		Prior Period Pool under/overcollection																				
37																						
38																						
39	C	Surcharge Subtotal	(4,561,677)	(89,257)	-	-	(113,174)	(684,947)	(610,364)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(246,777)	(427,248)	(64,290)	(36,082)	(14,405)	(14,664)	(14,858)	(7,370,353)
40																						
41																						
42	D	Net balance to be recovered (A-B+C)	49,982	6,541	-	-	67,892	588,985	1,769,048	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	589,062	1,098,962	4,354,279	10,605,732	3,394,023	449,835	576,828	[redacted]
43																						
44	E	Allocation of Litigated Recovery																				
45																						
46		Surcharge calculation																				
47		Unrecovered costs (D+E)																				
48		remaining life																				
49		one year																				
50	F	amortization																				
51																						
52		Required annual increase in rates:																				
53		smaller of D or F																				
54																						
55		forecasted therm sales																				
56																						
57		surcharge per therm																				

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019

Rate: $0.19 /MMBtu

	Rate	Volume	Total	
Injection Cost	$0.0087	**393,727**	$3,425	
Fuel (1.51%)	$0.0368	**393,727**	$14,474	
Withdrawal Cost	$0.0087	**199,601**	$1,737	
Delivery Rate	$0.0491	199,601	$9,808	
FTA Demand Charge	$0.2680	199,601	$53,499	
FTA Commodity Charge	$0.1181	199,601	$23,573	
Fuel (1.24%)	$0.0302	199,601	$6,026	
		Total Cost	$112,541	
	Absolute Value of the	Sendout Error	**593,327**	MMBtu
		Rate	$ 0.19	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in PK Schedule 6

TGP FSMA Injection Charge	$0.0087	/ MMBtu
TGP FSMA Withdrawal Charge	$0.0087	/ MMBtu
TGP FSMA Deliverability Charge	$1.4938	/ MMBtu per month
	$0.0491	/ MMBtu per day
TGP Z4-6 Demand Charge	$8.1481	/ MMBtu per month
	$0.2680	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.1181	/ MMBtu

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
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	760	737	23	1,752,809	1,715,381	37,429	79,740	58,584	21,155
Dec	1,233	1,228	5	2,570,842	2,562,788	8,054	78,927	43,490	35,437
Jan	1,241	1,211	30	2,583,728	2,535,405	48,323	109,532	78,927	30,604
Feb	881	867	14	1,968,944	1,945,717	23,226	81,213	52,220	28,994
Mar	904	849	55	2,178,809	2,071,641	107,168	134,447	120,807	13,640
Apr	417	422	-5	886,923	892,396	-5,473	36,119	15,323	20,796
May	277	290	-13	655,202	666,170	-10,968	31,217	10,124	21,092
Jun	46	50	-4	367,325	369,128	-1,803	5,409	1,803	3,606
Jul	15	16	-1	327,694	328,009	-315	315	0	315
Aug	11	12	-1	338,212	339,005	-793	3,965	1,586	2,379
Sep	60	65	-5	360,471	361,168	-697	2,369	836	1,533
Oct	198	208	-10	779,449	789,474	-10,025	30,075	10,025	20,050
Total	**6,043**	**5,955**	**88**	**14,770,409**	**14,576,283**	**194,126**	**593,327**	**393,727**	**199,601**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 2017	31	31	0	48,280	48,280	0	0	0	0
Apr 2, 17	24	24	0	40,619	40,619	0	0	0	0
Apr 3, 17	21	17	4	37,335	32,957	4,378	4,378	4,378	0
Apr 4, 17	27	27	0	43,902	43,902	0	0	0	0
Apr 5, 17	25	24	1	41,713	40,619	1,095	1,095	1,095	0
Apr 6, 17	22	25	-3	38,430	41,713	-3,284	3,284	0	3,284
Apr 7, 17	21	22	-1	37,335	38,430	-1,095	1,095	0	1,095
Apr 8, 17	23	24	-1	39,524	40,619	-1,095	1,095	0	1,095
Apr 9, 17	11	11	0	26,390	26,390	0	0	0	0
Apr 10, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 11, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 12, 17	9	11	-2	24,201	26,390	-2,189	2,189	0	2,189
Apr 13, 17	16	18	-2	31,863	34,052	-2,189	2,189	0	2,189
Apr 14, 17	14	16	-2	29,674	31,863	-2,189	2,189	0	2,189
Apr 15, 17	3	3	0	17,634	17,634	0	0	0	0
Apr 16, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 17, 17	11	9	2	26,390	24,201	2,189	2,189	2,189	0
Apr 18, 17	21	20	1	37,335	36,241	1,095	1,095	1,095	0
Apr 19, 17	16	18	-2	31,863	34,052	-2,189	2,189	0	2,189
Apr 20, 17	12	14	-2	27,485	29,674	-2,189	2,189	0	2,189
Apr 21, 17	20	22	-2	36,241	38,430	-2,189	2,189	0	2,189
Apr 22, 17	19	21	-2	35,146	37,335	-2,189	2,189	0	2,189
Apr 23, 17	9	9	0	24,201	24,201	0	0	0	0
Apr 24, 17	10	7	3	25,296	22,012	3,284	3,284	3,284	0
Apr 25, 17	18	18	0	34,052	34,052	0	0	0	0
Apr 26, 17	12	10	2	27,485	25,296	2,189	2,189	2,189	0
Apr 27, 17	5	5	0	19,823	19,823	0	0	0	0
Apr 28, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 29, 17	2	1	1	16,540	15,445	1,095	1,095	1,095	0
Apr 30, 17	15	15	0	30,768	30,768	0	0	0	0
May 1, 17	11	19	-8	22,877	29,627	-6,750	6,750	0	6,750
May 2, 17	8	10	-2	20,346	22,034	-1,687	1,687	0	1,687
May 3, 17	15	14	1	26,252	25,408	844	844	844	0
May 4, 17	10	10	0	22,034	22,034	0	0	0	0
May 5, 17	14	16	-2	25,408	27,096	-1,687	1,687	0	1,687
May 6, 17	7	7	0	19,503	19,503	0	0	0	0
May 7, 17	12	11	1	23,721	22,877	844	844	844	0
May 8, 17	19	20	-1	29,627	30,471	-844	844	0	844
May 9, 17	18	16	2	28,783	27,096	1,687	1,687	1,687	0
May 10, 17	13	12	1	24,565	23,721	844	844	844	0
May 11, 17	13	14	-1	24,565	25,408	-844	844	0	844
May 12, 17	12	13	-1	23,721	24,565	-844	844	0	844
May 13, 17	16	17	-1	27,096	27,940	-844	844	0	844
May 14, 17	18	18	0	28,783	28,783	0	0	0	0
May 15, 17	9	8	1	21,190	20,346	844	844	844	0
May 16, 17	0	0	0	13,597	13,597	0	0	0	0
May 17, 17	0	0	0	13,597	13,597	0	0	0	0
May 18, 17	0	0	0	13,597	13,597	0	0	0	0
May 19, 17	0	0	0	13,597	13,597	0	0	0	0
May 20, 17	6	4	2	18,659	16,972	1,687	1,687	1,687	0
May 21, 17	5	5	0	17,815	17,815	0	0	0	0
May 22, 17	12	13	-1	23,721	24,565	-844	844	0	844
May 23, 17	1	3	-2	14,440	16,128	-1,687	1,687	0	1,687
May 24, 17	3	4	-1	16,128	16,972	-844	844	0	844
May 25, 17	13	13	0	24,565	24,565	0	0	0	0
May 26, 17	11	9	2	22,877	21,190	1,687	1,687	1,687	0
May 27, 17	6	4	2	18,659	16,972	1,687	1,687	1,687	0
May 28, 17	3	5	-2	16,128	17,815	-1,687	1,687	0	1,687
May 29, 17	14	15	-1	25,408	26,252	-844	844	0	844
May 30, 17	7	7	0	19,503	19,503	0	0	0	0
May 31, 17	1	3	-2	14,440	16,128	-1,687	1,687	0	1,687
Jun 1, 17	1	0	1	12,004	11,553	451	451	451	0
Jun 2, 17	5	6	-1	13,807	14,258	-451	451	0	451
Jun 3, 17	7	6	1	14,708	14,258	451	451	451	0
Jun 4, 17	2	3	-1	12,455	12,905	-451	451	0	451
Jun 5, 17	12	13	-1	16,962	17,413	-451	451	0	451
Jun 6, 17	15	14	1	18,314	17,864	451	451	451	0
Jun 7, 17	2	1	1	12,455	12,004	451	451	451	0
Jun 8, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 9, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 10, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 11, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 12, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 13, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 14, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 15, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 16, 17	2	4	-2	12,455	13,356	-902	902	0	902
Jun 17, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 18, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 19, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 20, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 21, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 22, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 23, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 24, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 25, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 26, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 27, 17	0	3	-3	11,553	12,905	-1,352	1,352	0	1,352
Jun 28, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 29, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 30, 17	0	0	0	11,553	11,553	0	0	0	0
Jul 1, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 2, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 3, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 4, 17	0	0	0	10,418	10,418	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jul 5, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 6, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 7, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 8, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 9, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 10, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 11, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 12, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 13, 17	5	5	0	11,993	11,993	0	0	0	0
Jul 14, 17	1	2	-1	10,733	11,048	-315	315	0	315
Jul 15, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 16, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 17, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 18, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 19, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 20, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 21, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 22, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 23, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 24, 17	7	7	0	12,623	12,623	0	0	0	0
Jul 25, 17	2	2	0	11,048	11,048	0	0	0	0
Jul 26, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 27, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 28, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 29, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 30, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 31, 17	0	0	0	10,418	10,418	0	0	0	0
Aug 1, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 2, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 3, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 4, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 5, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 6, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 7, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 8, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 9, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 10, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 11, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 12, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 13, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 14, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 15, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 16, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 17, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 18, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 19, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 20, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 21, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 22, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 23, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 24, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 25, 17	1	2	-1	11,422	12,215	-793	793	0	793
Aug 26, 17	1	1	0	11,422	11,422	0	0	0	0
Aug 27, 17	1	0	1	11,422	10,629	793	793	793	0
Aug 28, 17	2	2	0	12,215	12,215	0	0	0	0
Aug 29, 17	4	3	1	13,800	13,007	793	793	793	0
Aug 30, 17	0	2	-2	10,629	12,215	-1,586	1,586	0	1,586
Aug 31, 17	2	2	0	12,215	12,215	0	0	0	0
Sep 1, 17	8	9	-1	12,852	12,991	-139	139	0	139
Sep 2, 17	3	3	0	12,155	12,155	0	0	0	0
Sep 3, 17	7	7	0	12,713	12,713	0	0	0	0
Sep 4, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 5, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 6, 17	0	3	-3	11,737	12,155	-418	418	0	418
Sep 7, 17	1	3	-2	11,876	12,155	-279	279	0	279
Sep 8, 17	4	4	0	12,294	12,294	0	0	0	0
Sep 9, 17	5	3	2	12,434	12,155	279	279	279	0
Sep 10, 17	4	2	2	12,294	12,016	279	279	279	0
Sep 11, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 12, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 13, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 14, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 15, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 16, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 17, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 18, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 19, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 20, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 21, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 22, 17	1	0	1	11,876	11,737	139	139	139	0
Sep 23, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 24, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 25, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 26, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 27, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 28, 17	5	4	1	12,434	12,294	139	139	139	0
Sep 29, 17	7	9	-2	12,713	12,991	-279	279	0	279
Sep 30, 17	15	18	-3	13,827	14,245	-418	418	0	418
Oct 1, 17	8	10	-2	26,760	28,765	-2,005	2,005	0	2,005
Oct 2, 17	6	8	-2	24,755	26,760	-2,005	2,005	0	2,005
Oct 3, 17	6	6	0	24,755	24,755	0	0	0	0
Oct 4, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 5, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 6, 17	2	3	-1	20,745	21,748	-1,003	1,003	0	1,003
Oct 7, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 8, 17	0	0	0	18,740	18,740	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Oct 9, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 10, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 11, 17	6	7	-1	24,755	25,758	-1,003	1,003	0	1,003
Oct 12, 17	14	17	-3	32,776	35,783	-3,008	3,008	0	3,008
Oct 13, 17	9	8	1	27,763	26,760	1,003	1,003	1,003	0
Oct 14, 17	1	1	0	19,743	19,743	0	0	0	0
Oct 15, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 16, 17	19	20	-1	37,788	38,791	-1,003	1,003	0	1,003
Oct 17, 17	15	16	-1	33,778	34,781	-1,003	1,003	0	1,003
Oct 18, 17	6	10	-4	24,755	28,765	-4,010	4,010	0	4,010
Oct 19, 17	4	2	2	22,750	20,745	2,005	2,005	2,005	0
Oct 20, 17	7	8	-1	25,758	26,760	-1,003	1,003	0	1,003
Oct 21, 17	3	4	-1	21,748	22,750	-1,003	1,003	0	1,003
Oct 22, 17	7	5	2	25,758	23,753	2,005	2,005	2,005	0
Oct 23, 17	1	2	-1	19,743	20,745	-1,003	1,003	0	1,003
Oct 24, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 25, 17	4	3	1	22,750	21,748	1,003	1,003	1,003	0
Oct 26, 17	17	16	1	35,783	34,781	1,003	1,003	1,003	0
Oct 27, 17	15	17	-2	33,778	35,783	-2,005	2,005	0	2,005
Oct 28, 17	8	5	3	26,760	23,753	3,008	3,008	3,008	0
Oct 29, 17	4	4	0	22,750	22,750	0	0	0	0
Oct 30, 17	16	16	0	34,781	34,781	0	0	0	0
Oct 31, 17	20	20	0	38,791	38,791	0	0	0	0
Nov 1, 17	14	16	-2	39,984	43,238	-3,255	3,255	0	3,255
Nov 2, 17	4	3	1	23,710	22,083	1,627	1,627	1,627	0
Nov 3, 17	12	10	2	36,729	33,474	3,255	3,255	3,255	0
Nov 4, 17	18	17	1	46,493	44,866	1,627	1,627	1,627	0
Nov 5, 17	9	7	2	31,847	28,592	3,255	3,255	3,255	0
Nov 6, 17	16	14	2	43,238	39,984	3,255	3,255	3,255	0
Nov 7, 17	25	25	0	57,885	57,885	0	0	0	0
Nov 8, 17	29	30	-1	64,394	66,021	-1,627	1,627	0	1,627
Nov 9, 17	24	22	2	56,257	53,003	3,255	3,255	3,255	0
Nov 10, 17	39	40	-1	80,667	82,295	-1,627	1,627	0	1,627
Nov 11, 17	35	37	-2	74,158	77,413	-3,255	3,255	0	3,255
Nov 12, 17	31	31	0	67,649	67,649	0	0	0	0
Nov 13, 17	29	30	-1	64,394	66,021	-1,627	1,627	0	1,627
Nov 14, 17	31	28	3	67,649	62,767	4,882	4,882	4,882	0
Nov 15, 17	29	29	0	64,394	64,394	0	0	0	0
Nov 16, 17	25	25	0	57,885	57,885	0	0	0	0
Nov 17, 17	32	33	-1	69,276	70,903	-1,627	1,627	0	1,627
Nov 18, 17	20	24	-4	49,748	56,257	-6,509	6,509	0	6,509
Nov 19, 17	28	27	1	62,767	61,139	1,627	1,627	1,627	0
Nov 20, 17	30	28	2	66,021	62,767	3,255	3,255	3,255	0
Nov 21, 17	22	19	3	53,003	48,120	4,882	4,882	4,882	0
Nov 22, 17	31	29	2	67,649	64,394	3,255	3,255	3,255	0
Nov 23, 17	33	32	1	70,903	69,276	1,627	1,627	1,627	0
Nov 24, 17	25	25	0	57,885	57,885	0	0	0	0
Nov 25, 17	21	16	5	51,375	43,238	8,137	8,137	8,137	0
Nov 26, 17	32	28	4	69,276	62,767	6,509	6,509	6,509	0
Nov 27, 17	35	36	-1	74,158	75,785	-1,627	1,627	0	1,627
Nov 28, 17	26	26	0	59,512	59,512	0	0	0	0
Nov 29, 17	30	26	4	66,021	59,512	6,509	6,509	6,509	0
Nov 30, 17	25	24	1	57,885	56,257	1,627	1,627	1,627	0
Dec 1, 17	28	29	-1	63,965	65,576	-1,611	1,611	0	1,611
Dec 2, 17	29	32	-3	65,576	70,408	-4,832	4,832	0	4,832
Dec 3, 17	30	29	1	67,187	65,576	1,611	1,611	1,611	0
Dec 4, 17	28	27	1	63,965	62,354	1,611	1,611	1,611	0
Dec 5, 17	17	16	1	46,247	44,636	1,611	1,611	1,611	0
Dec 6, 17	30	30	0	67,187	67,187	0	0	0	0
Dec 7, 17	31	29	2	68,797	65,576	3,222	3,222	3,222	0
Dec 8, 17	34	31	3	73,630	68,797	4,832	4,832	4,832	0
Dec 9, 17	34	35	-1	73,630	75,240	-1,611	1,611	0	1,611
Dec 10, 17	35	33	2	75,240	72,019	3,222	3,222	3,222	0
Dec 11, 17	37	34	3	78,462	73,630	4,832	4,832	4,832	0
Dec 12, 17	34	37	-3	73,630	78,462	-4,832	4,832	0	4,832
Dec 13, 17	44	44	0	89,737	89,737	0	0	0	0
Dec 14, 17	48	47	1	96,180	94,569	1,611	1,611	1,611	0
Dec 15, 17	42	43	-1	86,516	88,126	-1,611	1,611	0	1,611
Dec 16, 17	44	43	1	89,737	88,126	1,611	1,611	1,611	0
Dec 17, 17	44	44	0	89,737	89,737	0	0	0	0
Dec 18, 17	34	38	-4	73,630	80,073	-6,443	6,443	0	6,443
Dec 19, 17	27	24	3	62,354	57,522	4,832	4,832	4,832	0
Dec 20, 17	37	35	2	78,462	75,240	3,222	3,222	3,222	0
Dec 21, 17	42	42	0	86,516	86,516	0	0	0	0
Dec 22, 17	39	43	-4	81,683	88,126	-6,443	6,443	0	6,443
Dec 23, 17	33	32	1	72,019	70,408	1,611	1,611	1,611	0
Dec 24, 17	36	38	-2	76,851	80,073	-3,222	3,222	0	3,222
Dec 25, 17	43	40	3	88,126	83,294	4,832	4,832	4,832	0
Dec 26, 17	51	50	1	101,012	99,402	1,611	1,611	1,611	0
Dec 27, 17	59	57	2	113,899	110,677	3,222	3,222	3,222	0
Dec 28, 17	63	63	0	120,342	120,342	0	0	0	0
Dec 29, 17	60	61	-1	115,509	117,120	-1,611	1,611	0	1,611
Dec 30, 17	57	59	-2	110,677	113,899	-3,222	3,222	0	3,222
Dec 31, 17	63	63	0	120,342	120,342	0	0	0	0
Jan 1, 18	63	65	-2	120,342	123,563	-3,222	3,222	0	3,222
Jan 2, 18	53	52	1	104,234	102,623	1,611	1,611	1,611	0
Jan 3, 18	47	47	0	94,569	94,569	0	0	0	0
Jan 4, 18	46	45	1	92,959	91,348	1,611	1,611	1,611	0
Jan 5, 18	63	60	3	120,342	115,509	4,832	4,832	4,832	0
Jan 6, 18	67	63	4	126,785	120,342	6,443	6,443	6,443	0
Jan 7, 18	51	49	2	101,012	97,791	3,222	3,222	3,222	0
Jan 8, 18	37	35	2	78,462	75,240	3,222	3,222	3,222	0
Jan 9, 18	41	34	7	84,905	73,630	11,275	11,275	11,275	0
Jan 10, 18	32	31	1	70,408	68,797	1,611	1,611	1,611	0
Jan 11, 18	18	17	1	47,857	46,247	1,611	1,611	1,611	0
Jan 12, 18	14	8	6	41,414	31,750	9,665	9,665	9,665	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jan 13, 18	46	47	-1	92,959	94,569	-1,611	1,611	0	1,611
Jan 14, 18	52	52	0	102,623	102,623	0	0	0	0
Jan 15, 18	48	46	2	96,180	92,959	3,222	3,222	3,222	0
Jan 16, 18	38	36	2	80,073	76,851	3,222	3,222	3,222	0
Jan 17, 18	40	39	1	83,294	81,683	1,611	1,611	1,611	0
Jan 18, 18	41	42	-1	84,905	86,516	-1,611	1,611	0	1,611
Jan 19, 18	35	34	1	75,240	73,630	1,611	1,611	1,611	0
Jan 20, 18	28	27	1	63,965	62,354	1,611	1,611	1,611	0
Jan 21, 18	30	30	0	67,187	67,187	0	0	0	0
Jan 22, 18	30	36	-6	67,187	76,851	-9,665	9,665	0	9,665
Jan 23, 18	24	32	-8	57,522	70,408	-12,886	12,886	0	12,886
Jan 24, 18	43	41	2	88,126	84,905	3,222	3,222	3,222	0
Jan 25, 18	47	44	3	94,569	89,737	4,832	4,832	4,832	0
Jan 26, 18	40	39	1	83,294	81,683	1,611	1,611	1,611	0
Jan 27, 18	22	18	4	54,300	47,857	6,443	6,443	6,443	0
Jan 28, 18	27	28	-1	62,354	63,965	-1,611	1,611	0	1,611
Jan 29, 18	38	36	2	80,073	76,851	3,222	3,222	3,222	0
Jan 30, 18	43	42	1	88,126	86,516	1,611	1,611	1,611	0
Jan 31, 18	37	36	1	78,462	76,851	1,611	1,611	1,611	0
Feb 1, 18	29	29	0	65,576	65,576	0	0	0	0
Feb 2, 18	50	52	-2	99,402	102,623	-3,222	3,222	0	3,222
Feb 3, 18	41	41	0	84,905	84,905	0	0	0	0
Feb 4, 18	27	26	1	62,354	60,743	1,611	1,611	1,611	0
Feb 5, 18	40	39	1	83,294	81,683	1,611	1,611	1,611	0
Feb 6, 18	40	40	0	83,294	83,294	0	0	0	0
Feb 7, 18	38	39	-1	80,073	81,683	-1,611	1,611	0	1,611
Feb 8, 18	45	47	-2	91,348	94,569	-3,222	3,222	0	3,222
Feb 9, 18	37	38	-1	78,462	80,073	-1,611	1,611	0	1,611
Feb 10, 18	25	25	0	59,133	59,133	0	0	0	0
Feb 11, 18	28	29	-1	63,965	65,576	-1,611	1,611	0	1,611
Feb 12, 18	38	35	3	80,073	75,240	4,832	4,832	4,832	0
Feb 13, 18	38	36	2	80,073	76,851	3,222	3,222	3,222	0
Feb 14, 18	27	29	-2	62,354	65,576	-3,222	3,222	0	3,222
Feb 15, 18	20	21	-1	51,079	52,690	-1,611	1,611	0	1,611
Feb 16, 18	32	31	1	70,408	68,797	1,611	1,611	1,611	0
Feb 17, 18	33	33	0	72,019	72,019	0	0	0	0
Feb 18, 18	34	35	-1	73,630	75,240	-1,611	1,611	0	1,611
Feb 19, 18	20	19	1	51,079	49,468	1,611	1,611	1,611	0
Feb 20, 18	9	16	-7	33,361	44,636	-11,275	11,275	0	11,275
Feb 21, 18	17	10	7	46,247	34,971	11,275	11,275	11,275	0
Feb 22, 18	35	35	0	75,240	75,240	0	0	0	0
Feb 23, 18	27	27	0	62,354	62,354	0	0	0	0
Feb 24, 18	27	25	2	62,354	59,133	3,222	3,222	3,222	0
Feb 25, 18	31	29	2	68,797	65,576	3,222	3,222	3,222	0
Feb 26, 18	28	25	3	63,965	59,133	4,832	4,832	4,832	0
Feb 27, 18	24	21	3	57,522	52,690	4,832	4,832	4,832	0
Feb 28, 18	18	14	4	47,857	41,414	6,443	6,443	6,443	0
Mar 1, 18	23	21	2	58,728	54,831	3,897	3,897	3,897	0
Mar 2, 18	28	24	4	68,470	60,676	7,794	7,794	7,794	0
Mar 3, 18	28	23	5	68,470	58,728	9,743	9,743	9,743	0
Mar 4, 18	29	28	1	70,419	68,470	1,949	1,949	1,949	0
Mar 5, 18	30	29	1	72,367	70,419	1,949	1,949	1,949	0
Mar 6, 18	32	31	1	76,264	74,316	1,949	1,949	1,949	0
Mar 7, 18	31	33	-2	74,316	78,213	-3,897	3,897	0	3,897
Mar 8, 18	34	35	-1	80,161	82,110	-1,949	1,949	0	1,949
Mar 9, 18	33	32	1	78,213	76,264	1,949	1,949	1,949	0
Mar 10, 18	32	30	2	76,264	72,367	3,897	3,897	3,897	0
Mar 11, 18	32	32	0	76,264	76,264	0	0	0	0
Mar 12, 18	31	28	3	74,316	68,470	5,846	5,846	5,846	0
Mar 13, 18	34	33	1	80,161	78,213	1,949	1,949	1,949	0
Mar 14, 18	31	29	2	74,316	70,419	3,897	3,897	3,897	0
Mar 15, 18	31	29	2	74,316	70,419	3,897	3,897	3,897	0
Mar 16, 18	37	34	3	86,007	80,161	5,846	5,846	5,846	0
Mar 17, 18	44	42	2	99,646	95,749	3,897	3,897	3,897	0
Mar 18, 18	44	41	3	99,646	93,801	5,846	5,846	5,846	0
Mar 19, 18	40	37	3	91,852	86,007	5,846	5,846	5,846	0
Mar 20, 18	33	30	3	78,213	72,367	5,846	5,846	5,846	0
Mar 21, 18	29	27	2	70,419	66,522	3,897	3,897	3,897	0
Mar 22, 18	28	24	4	68,470	60,676	7,794	7,794	7,794	0
Mar 23, 18	26	23	3	64,573	58,728	5,846	5,846	5,846	0
Mar 24, 18	28	26	2	68,470	64,573	3,897	3,897	3,897	0
Mar 25, 18	34	31	3	80,161	74,316	5,846	5,846	5,846	0
Mar 26, 18	30	28	2	72,367	68,470	3,897	3,897	3,897	0
Mar 27, 18	25	22	3	62,625	56,779	5,846	5,846	5,846	0
Mar 28, 18	19	19	0	50,934	50,934	0	0	0	0
Mar 29, 18	14	17	-3	41,191	47,037	-5,846	5,846	0	5,846
Mar 30, 18	17	18	-1	47,037	48,985	-1,949	1,949	0	1,949
Mar 31, 18	20	14	6	52,882	41,191	11,691	11,691	11,691	0
Apr	417	422	-5	886,923	892,396	-5,473	36,119	15,323	20,796
May	277	290	-13	655,202	666,170	-10,968	31,217	10,124	21,092
Jun	46	50	-4	367,325	369,128	-1,803	5,409	1,803	3,606
Jul	15	16	-1	327,694	328,009	-315	315	0	315
Aug	11	12	-1	338,212	339,005	-793	3,965	1,586	2,379
Sep	60	65	-5	360,471	361,168	-697	2,369	836	1,533
Oct	198	208	-10	779,449	789,474	-10,025	30,075	10,025	20,050
Nov	760	737	23	1,752,809	1,715,381	37,429	79,740	58,584	21,155
Dec	1,233	1,228	5	2,570,842	2,562,788	8,054	78,927	43,490	35,437
Jan	1,241	1,211	30	2,583,728	2,535,405	48,323	109,532	78,927	30,604
Feb	881	867	14	1,968,944	1,945,717	23,226	81,213	52,220	28,994
Mar	904	849	55	2,178,809	2,071,641	107,168	134,447	120,807	13,640
Total	6,043	5,955	88	14,770,409	14,576,283	194,126	593,327	393,727	199,601

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		164,571	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 95346	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	30,000		
10			79,718	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		56,738	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,969,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$0		Attachment B Page 3 Line 1
27	Total		$6,949,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$122.48		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$20.41**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations

Resource Type	High Load Factor	Low Load Factor
Pipeline	59 0%	47 2%
Storage	13 6%	17 5%
Peaking	27 4%	35 3%
TOTAL:	100 00%	100 00%

Capacity Resources effective November 1, 2017

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	TCPL + Union	FT to Parkway & IGTS	M12200 & 41232	4,000		$14 5544		10/31/2022	
	Iroquois	RTS to Wright	470-01	4,047		$5 5997		11/1/2022	
	TGP	NET-NE (Z5-Z6)	95346	4,000		$7 1569		11/30/2021	
	TGP	FT-A (Z5-Z6)	2302	3,122		$7 1569		10/31/2020	
	TGP	FT-A (Z0-Z6)	8587	7,035		$23 2175		10/31/2020	
	TGP	FT-A (Z1-Z6)	8587	14,561		$20 6094		10/31/2020	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4 7453		10/31/2020	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12 1916		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523*	21,844	1,560,391	$1.4938	$0.0205	10/31/2020	
	TGP	FT-A (Z4-Z6)	632	15,265		$8.1481		10/31/2020	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.1481		10/31/2020	
	National Fuel	FSS-1 (Storage)	O02357*	6,098	670,800	$2.4329	$0.0373	3/31/2020	
	National Fuel	FST (Transport)	N02358	6,098		$3.7049		3/31/2020	
	TGP	FT-A (Z4-Z6)	11234	6,150		$8.1481		10/31/2020	
	Honeoye	SS-NY (Storage)	SS-NY**	1,957	245,380	$4.4683	$0.0000	4/1/2020	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$7.1569		10/31/2020	
	Dominion	GSS (Storage)	300076*	934	102,700	$1 8683	$0.0145	3/31/2021	
	TGP	FT-A (Z4-Z6)	11234	932		$8.1481		10/31/2020	
Peaking									
	Energy North	LNG/Propane****		56,738	-	$20.4100	$0 0000		X

* 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 11/01/18. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the EnergyNorth 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 $18.2633 /dth.

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

		Volume	Rate	Monthly Cost	Months/Year	Annual Cost
1		[redacted]				
2						
3						
4	Concord Lateral	[redacted]				
5	ENGIE					
6						
7	Subtotal					**$4,969,000** *
8						
9	**Total**					**$4,969,000**
10						

* Contract currently being negotiated for an effective date of November 1, 2018

REDACTED

Liberty Utilities (EnergyNorth Natural Gas) Corp

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	47.2%	17.5%	35.3%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	59.0%	13.6%	27.4%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	59.0%	13.6%	27.4%	100.0%

HLF	High Load Factor	58.97%	13.60%	27.44%	100%
LLF	Low Load Factor	47.23%	17.48%	35.28%	100%
	Total	48.44%	17.08%	34.48%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD		Base load	71.386 Heat load	Total
HLF	R-1 RNSH	109	469	578
LLF	R-3 RSH	4,189	67,700	71,889
LLF	G-41 SL	1,045	29,440	30,485
HLF	G-51 SH	670	1,886	2,556
LLF	G-42 ML	1,566	36,248	37,813
HLF	G-52 MH	1,846	3,535	5,381
LLF	G-43 LL	587	6,881	7,468
HLF	G-53 LLL90	1,412	2,480	3,893
HLF	G-54 LLG90	382	4,126	4,507
	TOTAL	11,806	152,765	164,571

HLF	4,420	12,496	16,916
LLF	7,387	140,269	147,655
Total	11,806	152,765	164,571

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	109	208	318	86	174.16	578
R-3 RSH	4,189	30,096	34,285	12,460	25,144	71,889
G-41 SL	1,045	13,087	14,133	5,418	10,934	30,485
G-51 SH	670	839	1,509	347	701	2,556
G-42 ML	1,566	16,114	17,680	6,671	13,463	37,813
G-52 MH	1,846	1,571	3,418	651	1,313	5,381
G-43 LL	587	3,059	3,646	1,266	2,556	7,468
G-53 LLL90	1,412	1,103	2,515	457	921	3,893
G-54 LLG90	382	1,834	2,216	759	1,532	4,507
TOTAL	11,806	67,912	79,718	28,115	56,738	164,571

HLF	4,420	5,555	9,975	2,300	4,641	16,916
LLF	7,387	62,356	69,743	25,815	52,097	147,655
Total	11,806	67,912	79,718	28,115	56,738	164,571

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	54 9%	14.9%	30.1%	100.0%
R-3 RSH	47.7%	17.3%	35.0%	100.0%
G-41 SL	46.4%	17.8%	35 9%	100.0%
G-51 SH	59.0%	13.6%	27.4%	100.0%
G-42 ML	46 8%	17.6%	35.6%	100.0%
G-52 MH	63 5%	12.1%	24.4%	100.0%
G-43 LL	48 8%	17.0%	34 2%	100.0%
G-53 LLL90	64.6%	11.7%	23.7%	100.0%
G-54 LLG90	49 2%	16.8%	34.0%	100.0%
TOTAL	48.4%	17.1%	34 5%	100.0%

High Load Factor	58.97%	13.60%	27.44%	100%
Low Load Factor	47.23%	17.48%	35.28%	100%
Total	48.44%	17.08%	34.48%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Design DD **71.386**

	Daily Baseload * 1000	March Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	109	6.530	466	575
R-3 RSH	4,189	942.720	67,297	71,486
G-41 SL	1,045	409.946	29,264	30,310
G-51 SH	670	26.266	1,875	2,545
G-42 ML	1,566	504.747	36,032	37,598
G-52 MH	1,846	49.223	3,514	5,360
G-43 LL	587	95.816	6,840	7,427
G-53 LLL90	1,412	34.540	2,466	3,878
G-54 LLG90	382	57.448	4,101	4,483
TOTAL	11,806	2,294.712	151,855	163,661

HLF	4,420	174	12,422	16,841
LLF	7,387	2,121	139,433	146,820
Total	11,806	2,295	151,855	163,661

Design Day from 2018-2019 COG	**164,571**
Design Day from Billing Calculation	163,661
Variance	910

	Baseload as % of Total Class Load	Heat Load as % of Total
R-1 RNSH	19%	0.307%
R-3 RSH	6%	44.317%
G-41 SL	3%	19.271%
G-51 SH	26%	1.235%
G-42 ML	4%	23.728%
G-52 MH	34%	2.314%
G-43 LL	8%	4.504%
G-53 LLL90	36%	1.624%
G-54 LLG90	9%	2.701%
TOTAL		100.000%

Allocate Design Day Sendout to Rate Classes

	Base Load	Heat Load	Total
R-1 RNSH	109	469	578
R-3 RSH	4,189	67,700	71,889
G-41 SL	1,045	29,440	30,485
G-51 SH	670	1,886	2,556
G-42 ML	1,566	36,248	37,813
G-52 MH	1,846	3,535	5,381
G-43 LL	587	6,881	7,468
G-53 LLL90	1,412	2,480	3,893
G-54 LLG90	382	4,126	4,507
TOTAL	11,806	152,765	164,571

Liberty Utilities (EnergyNorth Natural Gas) Corp

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-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	5	7	9	10	9	8	6	6	4	3	3	4	73	3 385	0 109
LLF	R-3 RSH	319	689	1,132	1,127	939	780	467	217	144	115	120	161	6,212	129 864	4 189
LLF	G-41 SL	104	263	487	490	384	308	170	63	27	37	28	38	2,399	32 400	1 045
HLF	G-51 SH	26	36	47	47	43	38	35	32	21	21	22	25	394	20 777	0 670
LLF	G-42 ML	169	359	581	593	482	387	235	109	48	49	54	83	3,147	48 536	1 566
HLF	G-52 MH	74	88	108	109	99	88	76	80	58	56	57	74	968	57 235	1 846
LLF	G-43 LL	30	59	122	143	100	82	72	32	22	15	12	24	714	18 191	0 587
HLF	G-53 LLL90	52	59	74	94	73	67	67	59	44	43	47	60	739	43 783	1 412
HLF	G-54 LLL110	(1)	12	25	42	24	(1)	34	116	14	12	11	38	326	11 791	0 380
HLF	G-63 LLG110	0	0	21	63	37	0	0	0	0	0	0	0	122	0 036	0 001
	TOTAL	777	1,572	2,606	2,719	2,191	1,757	1,162	714	382	352	353	506	15,092	367 304	11 849
	HLF	156	202	284	366	286	200	218	293	141	136	139	201	2,622	137 007	4 462
	LLF	622	1,371	2,322	2,353	1,905	1,557	944	420	242	216	214	305	12,471	228 991	7 387

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

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	3	3	3	3	3	3	3	3	4	3	3	3	40
LLF	R-3 RSH	126	130	130	117	130	126	130	126	144	115	120	130	1,529
LLF	G-41 SL	31	32	32	29	32	31	32	31	27	37	28	32	381
HLF	G-51 SH	20	21	21	19	21	20	21	20	21	21	20	21	245
LLF	G-42 ML	47	49	49	44	49	47	49	47	48	49	47	49	571
HLF	G-52 MH	55	57	57	52	57	55	57	55	58	56	55	57	674
LLF	G-43 LL	18	18	18	16	18	18	18	18	22	15	12	18	214
HLF	G-53 LLL90	42	44	44	40	44	42	44	42	44	43	42	44	516
HLF	G-54 LLL110	(1)	12	12	11	12	(1)	12	11	14	12	11	12	139
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	372	397	397	359	397	371	397	384	413	383	369	397	4,325
	HLF	120	137	137	124	137	120	137	133	141	136	132	137	1,613
	LLF	222	229	229	207	229	222	229	222	242	216	207	229	2,696

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	R-1 RNSH	1	3	6	7	6	5	3	2	0	0	0	1	33
LLF	R-3 RSH	193	559	1,003	1,010	809	655	338	92	0	0	0	31	4,683
LLF	G-41 SL	73	231	454	460	352	277	138	31	0	0	0	6	2,017
HLF	G-51 SH	6	15	26	28	23	18	15	12	0	0	2	5	149
LLF	G-42 ML	122	310	532	549	433	340	186	62	0	0	7	34	2,575
HLF	G-52 MH	19	31	51	57	42	33	19	25	0	0	1	17	295
LLF	G-43 LL	12	41	104	127	82	64	54	14	0	0	0	6	499
HLF	G-53 LLL90	10	15	30	54	30	24	23	17	0	0	4	16	223
HLF	G-54 LLL110	0	0	13	32	12	0	22	105	0	0	0	26	187
HLF	G-63 LLG110	0	0	21	63	37	0	0	0	0	0	0	0	121
	TOTAL	406	1,175	2,209	2,360	1,794	1,385	765	330	(31)	(31)	(16)	109	10,768

HLF	36	65	147	242	149	80	81	161	0	0	7	64	1,008
LLF	400	1,142	2,093	2,146	1,676	1,335	715	199	0	0	7	76	9,775

Actual BDD	472.5	982.5	1219.5	1028.5	858.0	730.5	339.0	83.0	33.0	14.0	38.5	136.5	5935 5

Heat Factors

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total	AVG	AVG Peak
HLF	R-1 RNSH	0 0031	0 0033	0 0046	0 0066	0 0065	0 0063	0 0086	0 0286	0 0000	0 0000	0 0000	0 0044	0 0063	0 0060	0 0051
LLF	R-3 RSH	0 4085	0 5692	0 8221	0 9820	0 9427	0 8961	0 9957	1 1053	0 0000	0 0000	0 0000	0 2264	0 8961	0 5790	0 7701
LLF	G-41 SL	0 1538	0 2350	0 3724	0 4476	0 4099	0 3786	0 4063	0 3754	0 0000	0 0000	0 0000	0 0420	0 3786	0 2351	0 3329
HLF	G-51 SH	0 0117	0 0155	0 0215	0 0277	0 0263	0 0249	0 0430	0 1467	0 0000	0 0000	0 0422	0 0338	0 0249	0 0328	0 0213
LLF	G-42 ML	0 2579	0 3158	0 4363	0 5337	0 5047	0 4652	0 5501	0 7434	0 0000	0 0000	0 1809	0 2501	0 4652	0 3532	0 4189
HLF	G-52 MH	0 0392	0 0316	0 0417	0 0559	0 0492	0 0449	0 0557	0 2994	0 0000	0 0000	0 0338	0 1217	0 0449	0 0644	0 0438
LLF	G-43 LL	0 0263	0 0420	0 0854	0 1235	0 0958	0 0881	0 1580	0 1706	0 0000	0 0000	0 0000	0 0404	0 0881	0 0692	0 0768
HLF	G-53 LLL90	0 0213	0 0154	0 0247	0 0527	0 0345	0 0334	0 0674	0 2015	0 0000	0 0000	0 1092	0 1175	0 0334	0 0565	0 0303
HLF	G-54 LLL110	0 0000	0 0001	0 0110	0 0308	0 0140	0 0000	0 0646	1 2605	0 0000	0 0000	0 0000	0 1925	0 0000	0 1311	0 0093
HLF	G-63 LLG110	0 0000	0 0000	0 0169	0 0614	0 0435	0 0000	0 0003	0 0000	0 0000	0 0000	0 0000	0 0001	0 0000	0 0102	0 0203
	TOTAL	0 8584	1 1963	1 8112	2 2947	2 0911	1 8965	2 2581	3 9700	-0 9394	-2 2143	-0 4130	0 8015		1 1343	1 6914

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	**472.5**	**982.5**	**1,219.5**	**1,028.5**	**858.0**	**730.5**	**339.0**	**83.0**	**33.0**	**14.0**	**38.5**	**136.5**	**5935.5**
Norm Billing DD	**560.7**	**879.5**	**1134.3**	**1129.5**	**971.5**	**706.1**	**372.8**	**142.0**	**29.2**	**8.3**	**62.1**	**265.1**	**6261.0**

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

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	**R-1 RNSH**	5	6	9	10	10	8	7	7	4	3	3	5	76
LLF	**R-3 RSH**	355	630	1,062	1,226	1,046	758	501	283	144	115	120	190	6,431
LLF	**G-41 SL**	118	239	455	535	431	299	184	85	27	37	28	44	2,480
HLF	**G-51 SH**	27	34	45	50	46	38	37	41	21	21	23	30	412
LLF	**G-42 ML**	192	326	543	647	539	375	254	153	48	49	58	115	3,298
HLF	**G-52 MH**	77	85	105	115	105	87	78	98	58	56	57	89	1,011
LLF	**G-43 LL**	32	55	115	156	111	80	77	42	22	15	12	29	746
HLF	**G-53 LLL90**	54	57	72	99	77	66	69	71	44	43	49	75	777
HLF	**G-54 LLL110**	(1)	12	24	45	25	(1)	36	190	14	12	11	63	431
HLF	**G-63 LLG110**	0	0	19	69	42	0	0	0	0	0	0	0	131
	TOTAL	853	1,449	2,451	2,950	2,428	1,711	1,239	948	386	365	343	609	15,733

HLF	162	195	274	389	306	197	226	408	141	136	144	262	2,839
LLF	696	1,251	2,176	2,564	2,127	1,512	1,016	562	242	216	218	377	12,956

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2018 - 2019 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%				$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%				$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%				$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%				$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%	$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%	$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	29.6%	$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	29.8%	$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	15.1%	$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	15.8%	$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	15.2%	$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	11.4%	$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%
13	Nov 10 - Apr 11	12.6%	$0.0200	10,379,804	$ 207,596	$0.8420	$0.8029	$ 1,175.03	$ 1,138 58	$ 36.45	3 20%	$0 8434	$0.8030	$ 1,880 96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	11.9%	$0.0200	7,835,197	$ 156,704	$0.8126	$0.7309	$ 1,165.61	$ 1,089.44	$ 76.17	6 99%	$0 8129	$0.7327	$ 1,845 28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	10.9%	$0.0200	8,179,524	$ 163,590	$0.6919	$0.7680	$ 743.03	$ 792.48	$ (49.45)	-6 24%	$0.6936	$0.7724	$ 1,989 86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	10.5%	$0.0200	8,930,779	$ 178,616	$0.9095	$1.1011	$ 857.72	$ 981 21	$ (123.49)	-12 59%	$0 9108	$1.1057	$ 2,736 57	$ 3,117.48	$ (380 92)	-12 22%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.7321	$ 1,127.66	$ 948.07	$ 179.59	18 94%	$0.6312	$0.7403	$ 2,422.09	$ 2,635.27	$ (213.18)	-8.09%
18	Nov 15 - Apr 16	15.3%	$0.0200	4,941,157	$ 98,823	$0.7716	$0.7516	$ 869.15	$ 712.73	$ 156.42	21 95%						
19	Nov 16 - Apr 17	11.5%	$0.0106	5,419,967	$ 57,452	$0.7268	$0.7162	$ 827.14	$ 812 38	$ 14.76	1 82%						
20	Nov 17 - Apr 18	10.6%	$0.0200	5,298,900	$ 105,978	$0.6645	$0.6445	$ 878.70	$ 865 94	$ 12.76	1.47%						
21	Nov 18 - Apr 19					$0.7611	$0.7411	$ 984.83	$ 972.12	$ 12.71	1 31%						
22	Total									$ 734.45						$ 274.09	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2018 - 2019 Winter Cost of Gas Filing
Short-Term Debt Limitations

		For Purposes of Fuel Financing
Total Direct Gas Costs	$	61,003,856
Total Indirect Gas Costs		3,070,244
Total Gas Costs	$	64,074,101
% of Debt to Total Gas Costs		30%
Short Term Debt	$	19,222,230

		For Purposes Other Than Fuel Financing
12/31/2019 Projected Net Plant	**$**	**474,391,309**
% of Debt to Net Plant		20%
Short Term Debt	$	94,878,262

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
2018 - 2019 Winter Cost of Gas Filing

Company Allowance Calculation

	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-2017	Dec-2017	Jan-2018	Feb-2018	Mar-2018	Apr-2018	May-2018	Jun-2018	Total
Total Sendout- Therms	5,306,840	5,772,930	5,860,490	7,994,340	17,861,650	28,637,450	30,624,660	21,366,370	21,723,760	15,818,960	6,945,470	5,806,070	173,718,990
Total Throughput- Therms	5,477,505	5,417,274	5,774,031	5,961,899	9,536,108	19,770,779	30,048,336	27,009,800	21,555,424	20,558,307	12,636,576	6,839,328	170,585,367
Variance	(170,665)	355,656	86,459	2,032,441	8,325,542	8,866,671	576,324	(5,643,430)	168,336	(4,739,347)	(5,691,106)	(1,033,258)	3,133,623
Company Allowance													**1.80%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-2017	Dec-2017	Jan-2018	Feb-2018	Mar-2018	Apr-2018	May-2018	Jun-2018	Total
Total Sendout- Therms	5,306,840	5,772,930	5,860,490	7,994,340	17,861,650	28,637,450	30,624,660	21,366,370	21,723,760	15,818,960	6,945,470	5,806,070	173,718,990
Total Throughput- Therms	5,477,505	5,417,274	5,774,031	5,961,899	9,536,108	19,770,779	30,048,336	27,009,800	21,555,424	20,558,307	12,636,576	6,839,328	170,585,367
Company Use	5,787	4,233	5,020	7,859	21,786	44,117	97,872	59,687	46,735	37,832	13,658	6,029	350,615
Variance	(176,452)	351,423	81,439	2,024,582	8,303,756	8,822,554	478,452	(5,703,117)	121,601	(4,777,179)	(5,704,764)	(1,039,287)	2,783,008
LAUF													**1.60%**

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

Fuel Inventory Revenue Requirement

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**5 Quarter Avg**	**Q2 2017**	**Q3 2017**	**Q4 2017**	**Q1 2018**	**Q2 2018**
2	Gas Stored Underground	$ 2,620,073	$ 2,624,008	$ 3,950,391	$ 3,348,517	$ 836,781	$ 2,340,667
3	Fuel Stock - Propane	$ 1,069,605	$ 872,312	$ 906,758	$ 954,781	$ 1,318,235	$ 1,295,942
4	UG Storage - LNG	$ 66,153	$ 79,815	$ 87,853	$ 43,445	$ 54,602	$ 65,051
5		$ 3,755,832					
6	ROR	6.8%	Pre-Tax Rate of 6.29% & Statutory Tax Rate of 27.24%				
		$ 255,397					
7	Income Tax Gross-up	1.3744					
8	Revenue Requirement	$ 351,017					