

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

2 **d/b/a Liberty**

3 **Peak 2021 - 2022 Winter Cost of Gas Filing**

4 **Summary**

5

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7

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9 **Anticipated Direct Cost of Gas**

10 Purchased Gas:

11 Demand Costs:

12 Supply Costs

13

14 Storage Gas:

15 Demand, Capacity:

16 Commodity Costs:

17

18 Produced Gas:

19

20 Hedge Contract (Savings)/Loss

21 Hedge Underground Storage Contract (Savings)/Loss

22

23 **Total Unadjusted Cost of Gas**

24

25 **Adjustments:**

26

27 Prior Period (Over)/Under Recovery

28 Interest 05/01/20 - 4/30/21

29 Fuel Inventory Revenue Req

30 Refunds from Suppliers

31 Broker Revenues

32 Fuel Financing

33 Transportation CGA Revenues

34 Interruptible Sales Margin

35 Capacity Release and Off System Sales Margins

36 Hedging Costs

37 Fixed Price Option Administrative Costs

38

39 **Total Adjustments**

40

41 **Total Anticipated Direct Costs**

42

43 **Anticipated Indirect Cost of Gas**

44 **Working Capital**

45 Total Unadjusted Anticipated Cost of Gas

46 Lead Lag Days / 365

47 Prime Rate

48 Working Capital Percentage

49 Working Capital

50 Plus: Working Capital Reconciliation

51

52 **Total Working Capital Allowance**

53

54 **Bad Debt**

55 Total Unadjusted Anticipated Cost of Gas

56 Less Refunds

57 Plus Working Capital

58 Plus Prior Period (Over) Under Recovery

59 Subtotal

60 Bad Debt Percentage

61

62 Bad Debt Allowance

63 Prior Period Bad Debt Allowance

64

65 **Total Bad Debt Allowance**

66

67 **Production and Storage Capacity**

68

69

70 **Miscellaneous Overhead**

71

72 **Total Anticipated Indirect Cost of Gas**

73

74 **Total Cost of Gas**

75

76 **Projected Forecast Sales (Therms)**

Reference  
(b)

PK 21-22  
Nov - Apr  
(c)

		\$	12,887,000
			72,351,034
		\$	981,898
			6,130,435
		\$	2,299,384
		\$	-
		\$	-
		<u>\$</u>	<u>94,649,751</u>
		\$	1,431,639
			44,085
			335,667
			-
			(3,600)
			-
			(6,938)
			-
			(1,676,512)
			-
			36,800
		<u>\$</u>	<u>161,141</u>
		<u>\$</u>	<u>94,810,891</u>
		\$	94,649,751
			0.0705
			3.25%
			0.229%
			216,761
			(14,859)
		<u>\$</u>	<u>201,902</u>
		\$	94,649,751
			-
			201,902
			1,431,639
		<u>\$</u>	<u>96,283,291</u>
			0.70%
		\$	673,983
			(223,340)
		<u>\$</u>	<u>450,643</u>
		<u>\$</u>	<u>3,685,458</u>
		<u>\$</u>	<u>-</u>
		<u>\$</u>	<u>4,338,002</u>
		<u>\$</u>	<u>99,148,894</u>
			87,443,741

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7 For Month of:	(a)	(b)	Peak Costs May 21 - Oct 21 (c)	Nov-21 (d)	Dec-21 (e)	Jan-22 (f)	Feb-22 (g)	Mar-22 (h)	Apr-22 (i)	May-22 (j)	Peak Period Nov - Apr (k)
9 I. Gas Volumes (Therms)										1,139,930	1.2%
11 A. Firm Demand Volumes											
12 Firm Gas Sales		Sch. 10B, ln 23	-	3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741
13 Lost Gas (Unaccounted for)			-	131,257	200,043	232,437	192,597	165,642	95,906		1,017,882
14 Company Use			-	15,738	23,986	27,870	23,093	19,861	11,500		122,048
15 Unbilled Therms			-	8,836,890	549,888	492,921	107,722	220,489	(249,614)	(4,325,377)	5,632,919
17 Total Firm Volumes		Sch. 6, ln 97	-	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211		94,216,591
19 B. Supply Volumes (Therms)											
20 Pipeline Gas:											
21 Dawn Supply		Sch. 6, ln 66	-	876,821	926,304	927,705	840,605	911,138	750,758		5,233,331
22 Niagara Supply		Sch. 6, ln 67	-	691,567	730,181	731,285	662,478	718,226	679,016		4,212,753
23 TGP Supply (Direct)		Sch. 6, ln 68	-	4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346		17,283,547
24 Dracut Supply 1 - Baseload		Sch. 6, ln 69	-	-	2,800,032	4,674,030	3,176,712	-	-		10,650,774
25 Dracut Supply 2 - Swing		Sch. 6, ln 70	-	1,775,785	5,569,137	771,324	-	969,754	79,714		9,165,713
26 Dracut Supply 3 - Swing		Sch. 6, ln 71	-	-	596,455	290,490	-	1,484	-		888,430
27 Constellation COMBO		Sch. 6, ln 72	-	89,306	231,576	1,424,042	1,188,519	1,411,967	-		4,345,410
28 LNG Truck		Sch. 6, ln 73	-	20,666	21,875	51,371	291,824	362,081	-		747,817
29 Propane Truck		Sch. 6, ln 74	-	-	-	-	695,072	-	-		695,072
30 PNGTS		Sch. 6, ln 75	-	219,205	231,576	231,926	209,962	227,785	193,487		1,313,941
31 Portland Natural Gas		Sch. 6, ln 76	-	1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355		6,284,969
32 TGP Supply (Z4)		Sch. 6, ln 77	-	1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071		14,753,578
33 Subtotal Pipeline Volumes			-	11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749		75,575,334
35 Storage Gas:											
36 TGP Storage		Sch. 6, ln 82	-	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085		19,999,699
38 Produced Gas:											
39 LNG Vapor		Sch. 6, ln 85	-	21,404	421,875	547,315	694,098	273,045	21,015		1,978,752
40 Propane		Sch. 6, ln 86	-	-	-	244,014	574,010	-	-		818,023
41 Subtotal Produced Gas			-	21,404	421,875	791,328	1,268,108	273,045	21,015		2,796,775
43 Less - Gas Refill:											
44 LNG Truck		Sch. 6, ln 91	-	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-		(747,817)
45 Propane		Sch. 6, ln 92	-	-	-	-	(695,072)	-	-		(695,072)
46 TGP Storage Refill		Sch. 6, ln 93	-	(1,750,690)	-	-	-	-	(961,638)		(2,712,328)
47 Subtotal Refills			-	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)		(4,155,217)
49 Total Firm Sendout Volumes		Ins 33 + 36 + 41 + 47	-	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211		94,216,591

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4 Summary of Supply and Demand Forecast

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51 II. Gas Costs

52 A. Demand Costs		Peak Costs									Peak Period			
53	54	55	56 For Month of:	57 (a)	58 (b)	May 21 - Oct 21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Nov - Apr
59	60	61	62	63	64	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
59	Niagara Supply	Sch.5A, In 12												
60	Subtotal Supply Demand													
61	Less Capacity Credit													
62	Net Pipeline Demand Costs													
64	Pipeline:													
65	Iroquois Gas Trans Service RTS 470-0	Sch.5A, In 16												
66	Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, In 17												
67	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, In 18												
68	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, In 19												
69	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, In 20												
70	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, In 21												
71	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, In 22												
72	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	Sch.5A, In 23												
73	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, In 24												
74	Portland Natural Gas Trans Service	Sch.5A, In 25												
75	Portland Natural Gas	Sch.5A, In 26												
76	ANE (TransCanada via Union to Iroquois)	Sch.5A, In 27												
77	TransCanada via Union to Portland	Sch.5A, In 28												
78	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, In 29												
79	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, In 30												
80	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, In 31												
81	National Fuel FST 2358	Sch.5A, In 32												
82	Subtotal Pipeline Demand					\$ 3,900,053	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 13,559,298
83	Less Capacity Credit					(1,320,558)	(405,527)	(405,527)	(405,527)	(405,527)	(405,527)	(405,527)	(405,527)	(3,753,722)
84	Net Pipeline Demand Costs					\$ 2,579,495	\$ 1,204,347	\$ 1,204,347	\$ 1,204,347	\$ 1,204,347	\$ 1,204,347	\$ 1,204,347	\$ 1,204,347	\$ 9,805,576
86	Peaking Supply:													
87	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, In 37												
88	Demand FLS	Sch.5A, In 38												
89	Constellation Demand	Sch.5A, In 39												
90	Subtotal Peaking Demand													
91	Less Capacity Credit													
92	Net Peaking Supply Demand Costs					\$ -	\$ 616,285	\$ 616,285	\$ 616,285	\$ 616,285	\$ 616,285	\$ -	\$ -	\$ 3,081,424
94	Storage:													
95	Dominion - Demand	Sch.5A, In 49												
96	Dominion - Storage	Sch.5A, In 50												
97	Honeoye - Demand	Sch.5A, In 51												
98	National Fuel - Demand	Sch.5A, In 52												
99	National Fuel - Capacity	Sch.5A, In 53												
100	Tenn Gas Pipeline - Demand	Sch.5A, In 54												
101	Tenn Gas Pipeline - Capacity	Sch.5A, In 55												
102	Subtotal Storage Demand					\$ 696,628	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 1,393,257
103	Less Capacity Credit					(235,878)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)	(411,359)
104	Net Storage Demand Costs					\$ 460,750	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 981,898
106	Total Demand Charges	Ins 60 + 82 + 90 + 102				\$ 4,596,681	\$ 2,549,779	\$ 2,549,779	\$ 2,549,779	\$ 2,549,779	\$ 2,549,779	\$ 1,725,979	\$ 1,725,979	\$ 19,071,554
107 v	Total Capacity Credit	Ins 61 + 83 + 91 + 103				(1,556,436)	(642,289)	(642,289)	(642,289)	(642,289)	(642,289)	(434,774)	(434,774)	(5,202,657)
108	Net Demand Charges					\$ 3,040,245	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,291,205	\$ 1,291,205	\$ 13,868,897

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111 B. Commodity Costs			Peak Costs							Peak Period	
			May 21 - Oct 21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Nov - Apr
			(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
112											
113											
114											
115											
116											
117	(a)	(b)									
118	<u>Pipeline:</u>										
119	Dawn Supply	Sch. 6, In 12									
120	Niagara Supply	Sch. 6, In 13									
121	TGP Supply (Direct)	Sch. 6, In 14									
122	Dracut Supply 1 - Baseload	Sch. 6, In 15									
123	Dracut Supply 2 - Swing	Sch. 6, In 16									
	Dracut Supply 3 - Swing	Sch. 6, In 17									
124	Constellation COMBO	Sch. 6, In 18									
125	LNG Truck	Sch. 6, In 19									
126	Propane Truck	Sch. 6, In 20									
127	PNGTS	Sch. 6, In 21									
128	Portland Natural Gas	Sch. 6, In 22									
129	TGP Supply (Z4)	Sch. 6, In 23									
130	Subtotal Pipeline Commodity Costs		\$ -	\$ 6,488,894	\$ 25,785,739	\$ 19,058,558	\$ 11,866,845	\$ 7,408,521	\$ 3,274,803		\$ 73,883,360
131											
132	<u>Storage:</u>										
133	TGP Storage - Withdrawals	Sch. 6, In 50	\$ -	\$ 838,477	\$ 258,921	\$ 1,676,210	\$ 1,489,505	\$ 1,449,899	\$ 417,423		\$ 6,130,435
134											
135	<u>Produced Gas Costs:</u>										
136	LNG Vapor	Sch. 6, In 53									
137	Propane	Sch. 6, In 54									
138	Subtotal Produced Gas Costs		\$ -	\$ 14,924	\$ 296,153	\$ 644,056	\$ 1,138,771	\$ 190,796	\$ 14,685		\$ 2,299,384
139											
140	<u>Less Storage Refills:</u>										
141	LNG Truck	Sch. 6, In 40									
142	Propane	Sch. 6, In 41									
143	TGP Storage Refill	Sch. 6, In 42									
144	Storage Refill (Trans.)	Sch. 6, In 43									
145	Subtotal Storage Refill		\$ -	\$ (1,077,566)	\$ (15,566)	\$ (37,152)	\$ (1,041,646)	\$ (244,164)	\$ (434,450)		\$ (2,850,544)
146											
147	Total Supply Commodity Costs		\$ -	\$ 6,264,728	\$ 26,325,246	\$ 21,341,673	\$ 13,453,475	\$ 8,805,052	\$ 3,272,462		\$ 79,462,636
148											
149	<u>C. Supply Volumetric Transportation Costs:</u>										
150	Dawn Supply	Sch. 6, In 28									
151	Niagara Supply	Sch. 6, In 29									
152	TGP Supply (Direct)	Sch. 6, In 30									
153	Dracut Supply 1 - Baseload	Sch. 6, In 31									
154	Dracut Supply 2 - Swing	Sch. 6, In 32									
	Dracut Supply 3 - Swing	Sch. 6, In 33									
155	Subtotal Pipeline Volumetric Trans. Costs		\$ -	\$ 249,688	\$ 204,758	\$ 198,077	\$ 171,484	\$ 172,367	\$ 41,655		\$ 1,038,029
156											
157	TGP Storage - Withdrawals	Sch. 6, In 35	\$ -	\$ 38,503	\$ 11,890	\$ 76,971	\$ 68,398	\$ 66,579	\$ 17,849		\$ 280,188
158											
159	Total Supply Volumetric Trans. Costs	Ins 155 + 157	\$ -	\$ 288,190	\$ 216,647	\$ 275,048	\$ 239,882	\$ 238,945	\$ 59,504		\$ 1,318,217
160											
161	Total Commodity Gas & Trans. Costs	Ins 147 + 159	\$ -	\$ 6,552,919	\$ 26,541,893	\$ 21,616,721	\$ 13,693,357	\$ 9,043,998	\$ 3,331,966		\$ 80,780,853
162											
163											

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164 D. Supply and Demand Costs by Source

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	(a)	(b)	Peak Costs							Peak Period		
			(c)	Nov-21 (d)	Dec-21 (e)	Jan-22 (f)	Feb-22 (g)	Mar-22 (h)	Apr-22 (i)	May-22 (j)	Nov - Apr (k)	
171	<b>Purchased Gas Demand Costs</b>											
172		Ins 60 + 82	\$ 3,900,053	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 13,559,298	
173		In 90	-	823,800	823,800	823,800	823,800	823,800	-	-	4,119,000	
174			\$ 3,900,053	\$ 2,433,674	\$ 2,433,674	\$ 2,433,674	\$ 2,433,674	\$ 2,433,674	\$ 1,609,874		\$ 17,678,298	
175		Ins 61 + 83 + 91	(1,320,558)	(613,043)	(613,043)	(613,043)	(613,043)	(613,043)	(405,527)		(4,791,298)	
176			\$ 2,579,495	\$ 1,820,632	\$ 1,820,632	\$ 1,820,632	\$ 1,820,632	\$ 1,820,632	\$ 1,204,347		\$ 12,887,000	
177	<b>Storage Gas Demand Costs</b>											
179		In 102	\$ 696,628	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105		\$ 1,393,257	
180		In 103	(235,878)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)			(411,359)	
181			\$ 460,750	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858		\$ 981,898	
182	<b>Total Demand Costs</b>											
183		Ins 176 + 181	\$ 3,040,245	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,291,205		\$ 13,868,897	
184	<b>Purchased Gas Supply</b>											
186		In 130	[REDACTED]									\$ 72,070,845
187		In 143	[REDACTED]									\$ 6,130,435
188		In 144	[REDACTED]									280,188
189		In 141	[REDACTED]									
190		In 142	[REDACTED]									
191		In 155	[REDACTED]									
192			\$ -	\$ 5,661,016	\$ 25,974,930	\$ 19,219,483	\$ 10,996,684	\$ 7,336,724	\$ 2,882,009		\$ 72,070,845	
193	<b>Storage Commodity Costs</b>											
195		In 133	\$ -	\$ 838,477	\$ 258,921	\$ 1,676,210	\$ 1,489,505	\$ 1,449,899	\$ 417,423		\$ 6,130,435	
196		In 157	-	38,503	11,890	76,971	68,398	66,579	17,849		280,188	
197			\$ -	\$ 876,979	\$ 270,810	\$ 1,753,181	\$ 1,557,903	\$ 1,516,478	\$ 435,272		\$ 6,410,624	
198	<b>Produced Gas Commodity Costs</b>											
199		In 138	\$ -	\$ 14,924	\$ 296,153	\$ 644,056	\$ 1,138,771	\$ 190,796	\$ 14,685		\$ 2,299,384	
200	<b>Subtotal Commodity Costs</b>											
201		Ins 192 + 197 + 199	\$ -	\$ 6,552,919	\$ 26,541,893	\$ 21,616,721	\$ 13,693,357	\$ 9,043,998	\$ 3,331,966		\$ 80,780,853	
202	<b>Hedge Contract (Savings)/Loss</b>											
203			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		\$ -	
204	<b>Total Commodity Costs</b>											
205		Ins 201 + 203	\$ -	\$ 6,552,919	\$ 26,541,893	\$ 21,616,721	\$ 13,693,357	\$ 9,043,998	\$ 3,331,966		\$ 80,780,853	
206	<b>Total Demand Costs</b>											
207		In 108	\$ 3,040,245	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,291,205		\$ 13,868,897	
208		In 205	-	6,552,919	26,541,893	21,616,721	13,693,357	9,043,998	3,331,966		80,780,853	
209	<b>Total Supply Costs</b>											
210		Ins 207 + 208	\$ 3,040,245	\$ 8,460,408	\$ 28,449,382	\$ 23,524,210	\$ 15,600,847	\$ 10,951,487	\$ 4,623,171		\$ 94,649,750	

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4 Peak 2021 - 2022 Winter Cost of Gas Filing  
5 Contracts Ranked on a per Unit Cost Basis

6	7	8	9	10	11	12
	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
	(a)	(b)	(c)	(d)	(e)	(f)

10 Demand Costs

11						
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	Tenn Gas Pipeline	358905 FTA Z6-Z6	Transportation	MDQ	40,000	
21	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
22	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
23	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
24	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
25	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
26	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
27	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
28	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
29	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
30	ANE (TransCanada via Union to Iroquois)	Dawn - Parkway to Iroquois	Transportation	MDQ	4,047	
31	TransCanada via Union to Portland	Dawn -Parkway to Portland	Transportation	MDQ	5,077	
32	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
33	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
34	Portland Natural Gas Trans Service	FT-208544	Transportation	MDQ	1,000	
35	Portland Natural Gas	FT 233320	Transportation	MDQ	5,000	
36	Peaking Demand	NSB041	Peaking	MDQ	10,000	

38 Supply Costs - Commodity

39	TGP Supply (Z4)		Pipeline	Dkt	1,475,358	
40	Niagara Supply		Pipeline	Dkt	421,275	
41	Constellation COMBO		Pipeline	Dkt	434,541	
42	TGP Supply (Direct)		Pipeline	Dkt	1,728,355	
43	Dawn Supply		Pipeline	Dkt	523,333	
44	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,065,077	
45	TGP Storage		Storage	Dkt	1,999,970	
46	PNGTS		Pipeline	Dkt	131,394	
47	Propane Truck		Pipeline	Dkt	69,507	
48	LNG Truck		Pipeline	Dkt	74,782	
49	Dracut Supply 2 - Swing		Pipeline	Dkt	916,571	
50	Dracut Supply 3 - Swing		Pipeline	Dkt	88,843	
51	Portland Natural Gas		Pipeline	Dkt	628,497	
52	Propane		Produced	Dkt	81,802	
53	LNG Vapor (Storage)		Produced	Dkt	197,875	

55 Supply Costs - Volumetric Transportation

56	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,065,077	
57	Dracut Supply 2 - Swing		Pipeline	Dkt	916,571	
58	Niagara Supply		Pipeline	Dkt	421,275	
59	Dawn Supply		Pipeline	Dkt	523,333	
60	TGP Storage - Withdrawals		Pipeline	Dkt	1,999,970	
61	TGP Supply (Direct)		Pipeline	Dkt	1,728,355	

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
2 d/b/a Liberty  
3 Peak 2021 - 2022 Winter Cost of Gas Filing  
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

		Prior Period Bal Apr-21 Ending Bal	May-21 31	Jun-21 30	Jul-21 31	Aug-21 31	Sep-21 30	Oct-21 31	Nov-21 30	Dec-21 31	Jan-22 31	Feb-22 28	Mar-22 31	Apr-22 30	May-21 31	Peak Period Total	
	Days in Month (b)	Plus May Billings (c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	
<b>10 Account 1920-1740 COG (Over)/Under Balance - Interest Calculation</b>																	
12			\$ 1,431,639	\$ 1,431,639	\$ 707,644	\$ 206,908	\$ 714,886	\$ 1,224,266	\$ 1,734,921	\$ 2,247,116	\$ (2,080,567)	\$ 6,650,087	\$ 7,220,444	\$ 3,857,680	\$ (1,459,154)	\$ (6,125,843)	\$ 1,431,639
13	Account 1920-1740 1/																
14	Fcst Direct Gas Costs (Inc U/G Hedges)	Schedule 5A	506,708	506,708	506,708	506,708	506,708	506,708	8,460,408	28,449,382	23,524,210	15,600,847	10,951,487	4,623,171	-	-	94,649,751
15	Production & Storage & Misc Overhead		-	-	-	-	-	-	614,243	614,243	614,243	614,243	614,243	614,243	-	-	3,685,458
16	Projected Revenues w/o Int.	In 52 * 59	-	-	-	-	-	-	(3,470,585)	(19,452,911)	(22,763,151)	(19,191,164)	(16,365,099)	(9,888,993)	(4,742,392)	-	(95,874,295)
17	Projected Unbilled Revenue		-	-	-	-	-	-	(9,688,864)	(10,291,768)	(10,832,213)	(10,950,320)	(11,192,067)	(10,918,387)	-	-	(63,873,618)
18	Reverse Prior Month Unbilled		-	-	-	-	-	-	9,688,864	10,291,768	10,832,213	10,950,320	11,192,067	10,918,387	-	-	63,873,618
19	Add Net Adjustments	Schedule 4	(1,233,644)	(1,008,659)	-	-	-	-	(243,108)	(283,455)	(283,617)	(282,374)	(279,025)	(278,672)	-	-	(2,242,302)
20	Gas Cost Billed	Account 1920-1740 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Monthly (Over)/Under Recovery		\$ 1,431,639	\$ 704,703	\$ 205,692	\$ 713,616	\$ 1,221,594	\$ 1,730,974	\$ 2,241,628	\$ (2,080,789)	\$ 6,643,789	\$ 7,201,327	\$ 3,843,888	\$ (1,462,460)	\$ (6,115,726)	\$ 50,153	\$ -
22	Average Monthly Balance	(In 12 + 21)/2	\$ 1,068,171	\$ 456,668	\$ 460,262	\$ 968,240	\$ 1,477,620	\$ 1,988,274	\$ 83,163	\$ 2,281,611	\$ 6,925,707	\$ 5,532,166	\$ 1,197,610	\$ (3,787,440)	\$ (3,037,845)		
23	Interest Rate	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%			
24	Interest Applied	In 22 * In 24 / 365 * Days of Month	\$ 2,940	\$ 1,216	\$ 1,270	\$ 2,673	\$ 3,947	\$ 5,488	\$ 222	\$ 6,298	\$ 19,117	\$ 13,793	\$ 3,306	\$ (10,117)	\$ -	\$ -	\$ 50,153
25	(Over)/Under Balance	In 21 + In 26	\$ 1,431,639	\$ 707,644	\$ 206,908	\$ 714,886	\$ 1,224,266	\$ 1,734,921	\$ 2,247,116	\$ (2,080,567)	\$ 6,650,087	\$ 7,220,444	\$ 3,857,680	\$ (1,459,154)	\$ (6,125,843)	\$ 50,153	50,153
26																	
27																	
28																	
29																	
30																	
31	<b>Calculation of COG with Interest</b>																
32																	
33																	
34	Beginning Balance	In 12	\$ 1,431,639	\$ 1,431,639	\$ 707,652	\$ 206,920	\$ 714,898	\$ 1,224,278	\$ 1,734,933	\$ 2,247,129	\$ (2,085,662)	\$ 6,644,669	\$ 7,214,753	\$ 3,851,930	\$ (1,465,043)	\$ (6,131,617)	\$ 1,431,639
35	Fcst Direct Gas Costs (Inc U/G Hedges)	In 13	506,708	506,708	506,708	506,708	506,708	506,708	8,460,408	28,449,382	23,524,210	15,600,847	10,951,487	4,623,171	-	-	94,649,751
36	Prod Storage & Misc Overhead	In 14	-	-	-	-	-	-	614,243	614,243	614,243	614,243	614,243	614,243	-	-	3,685,458
37	Projected Revenues with int.	In 52 * In 61	-	-	-	-	-	-	(3,470,585)	(19,452,911)	(22,763,151)	(19,191,164)	(16,365,099)	(9,888,993)	(4,742,392)	-	(95,874,295)
38	Projected Unbilled Revenue		-	-	-	-	-	-	(9,693,964)	(10,297,185)	(10,837,914)	(10,956,084)	(11,197,958)	(10,924,134)	-	-	(63,907,240)
39	Reverse Prior Month Unbilled		-	-	-	-	-	-	9,693,964	10,297,185	10,837,914	10,956,084	11,197,958	10,924,134	-	-	63,907,240
40	Add Net Adjustments	In 19	(1,233,644)	(1,008,659)	-	-	-	-	(243,108)	(283,455)	(283,617)	(282,374)	(279,025)	(278,672)	-	-	(3,892,553)
41	Gas Cost Billed	In 20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Add Interest	In 26	-	-	-	-	-	-	222	6,298	19,117	13,793	3,306	(10,117)	-	-	32,618
43	(Over)/Under Balance		\$ 1,431,639	\$ 704,703	\$ 205,700	\$ 713,628	\$ 1,221,606	\$ 1,730,986	\$ 2,241,640	\$ (2,085,655)	\$ 6,644,675	\$ 7,214,742	\$ 3,851,927	\$ (1,465,032)	\$ (6,131,587)	\$ 50,126	\$ 32,618
44	Average Monthly Balance		\$ 1,068,171	\$ 456,676	\$ 460,274	\$ 968,252	\$ 1,477,632	\$ 1,988,287	\$ 80,737	\$ 2,279,507	\$ 6,929,706	\$ 5,533,340	\$ 1,193,449	\$ (3,798,315)	\$ (3,040,745)		
45	Interest Applied	In 24 * In 44 / 365 * Days of Month	2,948	1,220	1,270	2,673	3,947	5,488	216	6,292	19,128	13,795	3,294	(10,146)	-	-	50,126
46	(Over)/Under Balance	-In 41 +In 42 + In 46	\$ 1,431,639	\$ 707,652	\$ 206,920	\$ 714,898	\$ 1,224,278	\$ 1,734,933	\$ 2,247,129	\$ (2,085,662)	\$ 6,644,669	\$ 7,214,753	\$ 3,851,930	\$ (1,465,043)	\$ (6,131,617)	\$ 50,126	50,126
47																	
48																	
49																	
50																	
51	Forecast Sendout Therms	Sch 1							12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211			94,216,591
52	Less Forecast Billing Therm Sales	Sch. 10B, In 23 Nov - May							3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377		87,443,741
53	Less Forecast Unaccounted For	Sch 1							131,257	200,043	232,437	192,597	165,642	95,906			1,017,882
54	Less Forecast Company Use	Sch 1							15,738	23,986	27,870	23,093	19,861	11,500			122,048
55	Unbilled Volumes								8,836,890	549,888	492,921	107,722	220,489	-249,614	-4,325,377		5,632,919
56	Gross Unbilled								8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296			5,632,919
57																	
58																	
59	COB w/o Interest	Sch. 3, pg. 4, In 207 col. (c)							\$ 1,0964	\$ 1,0964	\$ 1,0964	\$ 1,0964	\$ 1,0964	\$ 1,0964	\$ 1,0964	\$ 1,0964	\$ 1,0964
60																	
61	COG With Interest	Sch. 3, pg. 4, In 207 col. (d)							\$ 1,0970	\$ 1,0970	\$ 1,0970	\$ 1,0970	\$ 1,0970	\$ 1,0970	\$ 1,0970	\$ 1,0970	\$ 1,0970
62																	

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
2 d/b/a Liberty  
3 Peak 2021 - 2022 Winter Cost of Gas Filing  
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

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		Prior Period Bal	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Peak Period	
	Days in Month	Apr-21	31	30	31	31	30	31	30	31	31	28	31	30	31	Total	
(a)	(b)	Ending Bal + May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
<b>70 Account 1163-1422 Working Capital (Over)/Under Balance - Interest Calculation</b>																	
71																	
72	Beginning Balance	Account 1163-1422 1/	\$ (14,859)	\$ (14,859)	\$ (14,801)	\$ (15,276)	\$ (14,156)	\$ (13,033)	\$ (11,906)	\$ (10,777)	\$ (8,789)	\$ 4,665	\$ 10,130	\$ 5,749	\$ (3,680)	\$ (13,097)	\$ (14,859)
73	Days Lag		0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705
74	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
75	Forecast Working Capital	In 34 * 0.091%	1,160	1,160	1,160	1,160	1,160	1,160	1,160	19,375	65,153	53,874	35,728	25,080	10,588	-	216,761
76	Projected Revenues w/o Int.	In 116 * In 120	-	-	-	-	-	-	(7,213)	(40,427)	(47,306)	(39,883)	(34,010)	(20,551)	(9,856)	(199,245)	
77	Projected Unbilled Revenue								(20,135)	(21,388)	(22,511)	(22,757)	(23,259)	(22,690)	(22,690)	(132,741)	
78	Reverse Prior Month Unbilled									20,135	21,388	22,511	22,757	23,259	22,690	132,741	
79	Add Net Adjustments		(1,062)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	(2,657)	
80	Working Capital Billed	Account 1163-1422 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
81	Monthly (Over)/Under Recovery		\$ (14,859)	\$ (14,761)	\$ (15,236)	\$ (14,116)	\$ (12,996)	\$ (11,873)	\$ (10,746)	\$ (18,749)	\$ 4,684	\$ 10,109	\$ 5,730	\$ (3,682)	\$ (13,074)	\$ (262)	\$ 0
82	Average Monthly Balance	(In 72 + In 86)/2	\$ (14,810)	\$ (15,019)	\$ (14,696)	\$ (13,576)	\$ (12,453)	\$ (11,326)	\$ (14,765)	\$ (7,052)	\$ 7,387	\$ 7,930	\$ 1,033	\$ (8,377)	\$ (6,679)		
83	Interest Rate	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
84	Interest Applied	In 88 * In 90 / 365 * Days of Month	\$ (41)	\$ (40)	\$ (41)	\$ (37)	\$ (33)	\$ (31)	\$ (39)	\$ (19)	\$ 20	\$ 20	\$ 3	\$ (22)	\$ -	\$ (262)	
85	(Over)/Under Balance	In 86 + In 92	\$ (14,859)	\$ (14,801)	\$ (15,276)	\$ (14,156)	\$ (13,033)	\$ (11,906)	\$ (10,777)	\$ (18,789)	\$ 4,665	\$ 10,130	\$ 5,749	\$ (3,680)	\$ (13,097)	\$ (262)	\$ (262)
86																	
87																	
88																	
89																	
90																	
91																	
92																	
93																	
94																	
95																	
96																	
97	<b>Calculation of Working Capital with Interest</b>																
98																	
99																	
100	Beginning Balance	In 72	\$ (14,859)	\$ (14,859)	\$ (14,801)	\$ (15,276)	\$ (14,156)	\$ (13,033)	\$ (11,906)	\$ (10,777)	\$ (8,752)	\$ 4,757	\$ 10,287	\$ 5,960	\$ (3,422)	\$ (12,812)	\$ (14,859)
101	Forecast Working Capital	In 76	1,160	1,160	1,160	1,160	1,160	1,160	1,160	19,375	65,153	53,874	35,728	25,080	10,588	-	216,761
102	Projected Rev. with interest	In 116 * In 122	-	-	-	-	-	-	-	(7,203)	(40,373)	(47,243)	(39,830)	(33,964)	(20,524)	(9,842)	(198,979)
103	Projected Unbilled Revenue									(20,108)	(21,360)	(22,481)	(22,727)	(23,228)	(22,660)	(132,565)	
104	Reverse Prior Month Unbilled										20,108	21,360	22,481	22,727	23,228	22,660	132,565
105	Add Net Adjustments	In 82	-	(1,062)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	(2,657)
106	Working Capital Billed	In 84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Add Interest	In 92	-	-	-	-	-	-	(39)	(19)	20	20	3	(22)	-	(38)	
108	Monthly (Over)/Under Recovery		\$ (14,859)	\$ (14,761)	\$ (15,236)	\$ (14,116)	\$ (12,996)	\$ (11,873)	\$ (10,746)	\$ (18,752)	\$ 4,757	\$ 10,286	\$ 5,960	\$ (3,423)	\$ (12,813)	\$ 6	\$ 227
109	Average Monthly Balance		\$ (14,810)	\$ (15,019)	\$ (14,696)	\$ (13,576)	\$ (12,453)	\$ (11,326)	\$ (14,765)	\$ (6,998)	\$ 7,522	\$ 8,123	\$ 1,269	\$ (8,117)	\$ (6,403)		
110	Interest Applied	In 90 * In 110 / 365 * Days of Month	(41)	(40)	(41)	(37)	(33)	(31)	(39)	(19)	21	20	4	(22)	-	(259)	
111	(Over)/Under Balance	-In 107 +In 108 + In 112	\$ (14,859)	\$ (14,801)	\$ (15,276)	\$ (14,156)	\$ (13,033)	\$ (11,906)	\$ (10,777)	\$ (18,752)	\$ 4,757	\$ 10,287	\$ 5,960	\$ (3,422)	\$ (12,812)	\$ 6	\$ 6
112	Forecast Therm Sales	In 52							3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741	
113	Unbilled Therm	In 55							8,836,890	549,888	492,921	107,722	220,489	(249,614)			
114	Gross Unbilled								8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296			
115	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, In 224 col. (c)	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	
116	Working Capital Rate w/ Int.	Sch. 3, pg. 4, In 224 col. (d)	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	\$0.0023	



1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
2 d/b/a Liberty  
3 Peak 2021 - 2022 Winter Cost of Gas Filing  
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

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		Prior Period Bal	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Demand/Period	
	Days in Month	Apr-21	31	30	31	31	30	31	30	31	31	28	31	30	31	Total	
(a)	(b)	Ending Bal	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
		+ May Collections															
130	<b>Account 1920-1743 Bad Debt (Over)/Under Balance - Interest Calculation</b>																
131																	
132	Forecast Direct Gas Costs	In 34	\$ 506,708	\$ 506,708	\$ 506,708	\$ 506,708	\$ 506,708	\$ 506,708	\$ 8,460,408	\$ 28,448,382	\$ 23,524,210	\$ 15,600,847	\$ 10,951,487	\$ 4,623,171	\$ -	94,649,751	
133	Forecast Working Capital	In 101	1,160	1,160	1,160	1,160	1,160	1,160	4,516	65,153	53,874	35,728	25,080	10,588	-	201,902	
134	Prior Period Balance	In 42							238,607	238,607	238,607	238,607	238,607	238,607		1,431,639	
135	Total Forecast Direct Gas Costs & Working Capital		507,868	507,868	507,868	507,868	507,868	507,868	8,703,531	28,753,142	23,816,690	15,875,181	11,215,174	4,872,365	-	94,851,652	
136																	
137	<b>Beginning Balance</b>	Account 1920-1743 1/	\$ (223,340)	\$ (223,340)	\$ (252,014)	\$ (257,764)	\$ (254,915)	\$ (252,059)	\$ (249,172)	\$ (246,300)	\$ (242,363)	\$ (127,480)	\$ (60,766)	\$ (32,419)	\$ (25,087)	\$ (32,220)	\$ (223,340)
138																	
139	Forecast Bad Debt	In 135 * 0.007	3,555	3,555	3,555	3,555	3,555	3,555	60,925	201,272	166,717	111,126	78,506	34,107	-	673,983	
140																	
141	Projected Revenues w/o int	In 178 * In 182	-	-	-	-	-	-	(14,858)	(83,278)	(97,450)	(82,158)	(70,059)	(42,335)	(20,302)	(410,440)	
142	Projected Unbilled Revenue								(41,478)	(44,059)	(46,373)	(46,879)	(47,914)	(46,742)		(273,445)	
143	Reverse Prior Month Unbilled									41,478	44,059	46,373	46,879	47,914	46,742	273,445	
144																	
145	Bad Debt Billed	Account 1920-1743 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
146																	
147	Add Net Adjustments		(31,575)	(8,627)	-	-	-	-	-	-	-	-	-	-	-	(40,203)	
148																	
149	Monthly (Over)/Under Recovery		\$ (223,340)	\$ (251,360)	\$ (257,086)	\$ (254,209)	\$ (251,360)	\$ (248,504)	\$ (245,617)	\$ (241,711)	\$ (126,951)	\$ (60,507)	\$ (32,303)	\$ (25,008)	\$ (32,144)	\$ (5,781)	\$ 0
150																	
151	Average Monthly Balance	(In 137 + In 149)/2	\$ (237,350)	\$ (254,550)	\$ (255,986)	\$ (253,138)	\$ (250,281)	\$ (247,395)	\$ (244,006)	\$ (184,657)	\$ (93,984)	\$ (46,535)	\$ (28,714)	\$ (28,615)	\$ (19,000)		
152																	
153	Interest Rate	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%			
154																	
155	Interest Applied	In 151 * In 153 / 365 * Days of Month	\$ (653)	\$ (678)	\$ (707)	\$ (699)	\$ (669)	\$ (683)	\$ (652)	\$ (510)	\$ (259)	\$ (116)	\$ (79)	\$ (76)		\$ (5,781)	
156																	
157	<b>(Over)/Under Balance</b>	In 149 + In 155	\$ (223,340)	\$ (252,014)	\$ (257,764)	\$ (254,915)	\$ (252,059)	\$ (249,172)	\$ (246,300)	\$ (242,363)	\$ (127,480)	\$ (60,766)	\$ (32,419)	\$ (25,087)	\$ (32,220)	\$ (5,781)	\$ (5,781)
158																	
159																	
160	<b>Calculation of Bad Debt with Interest</b>																
161																	
162	<b>Beginning Balance</b>	In 137	\$ (223,340)	\$ (223,340)	\$ (252,016)	\$ (257,768)	\$ (254,919)	\$ (252,063)	\$ (249,176)	\$ (246,304)	\$ (241,586)	\$ (125,490)	\$ (57,413)	\$ (27,920)	\$ (19,602)	\$ (26,165)	\$ (223,340)
163	Forecast Bad Debt	In 139	3,555	3,555	3,555	3,555	3,555	3,555	60,925	201,272	166,717	111,126	78,506	34,107	-	673,983	
164	Projected Revenues with int.	In 178 * In 184	-	-	-	-	-	-	(14,652)	(82,124)	(96,099)	(81,019)	(69,088)	(41,748)	(20,021)	(404,751)	
165	Projected Unbilled Revenue								(40,903)	(43,449)	(45,730)	(46,229)	(47,249)	(46,084)		(269,654)	
166	Reverse Prior Month Unbilled									40,903	43,449	45,730	46,229	47,249	46,084	269,654	
167	Bad Debt Billed	In 145	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
168	Add Interest	In 155	-	-	-	-	-	-	(652)	(510)	(259)	(116)	(79)	(76)	-	(1,693)	
169	Add Net Adjustments	In 147	(31,575)	(8,627)	-	-	-	-	-	-	-	-	-	-	-	(40,203)	
170	Monthly (Over)/Under Recovery		\$ (223,340)	\$ (251,360)	\$ (257,088)	\$ (254,213)	\$ (251,364)	\$ (248,508)	\$ (245,621)	\$ (241,586)	\$ (125,493)	\$ (57,413)	\$ (27,920)	\$ (19,602)	\$ (26,165)	\$ (92)	\$ 3,997
171																	
172	Average Monthly Balance		\$ (237,350)	\$ (254,552)	\$ (255,990)	\$ (253,142)	\$ (250,285)	\$ (247,399)	\$ (243,945)	\$ (183,540)	\$ (91,451)	\$ (42,667)	\$ (23,761)	\$ (22,883)	\$ (13,128)		
173																	
174	Interest Applied	In 153 * In 172 / 365 * Days of Month	(655)	(680)	(707)	(699)	(669)	(683)	(652)	(507)	(259)	(116)	(79)	(76)	-	\$ (5,781)	
175																	
176	<b>(Over)/Under Balance</b>	-In 168 +In 170 + In 174	\$ (223,340)	\$ (252,016)	\$ (257,768)	\$ (254,919)	\$ (252,063)	\$ (249,176)	\$ (246,304)	\$ (241,586)	\$ (125,490)	\$ (57,413)	\$ (27,920)	\$ (19,602)	\$ (26,165)	\$ (92)	\$ (92)
177																	
178	Forecast Term Sales	In 52							3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741	
179	Unbilled Therm	In 55							8,836,890	549,888	492,921	107,722	220,489	(249,614)			
180	Gross Unbilled								8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296			
181																	
182	COG Rate Without Interest	Sch. 3, pg. 4, In 241 col. (c)							\$0.0047	\$0.0047	\$0.0047	\$0.0047	\$0.0047	\$0.0047	\$0.0047	\$0.0047	
183																	
184	COG With Interest	Sch. 3, pg. 4, In 241 col. (d)							\$0.0046	\$0.0046	\$0.0046	\$0.0046	\$0.0046	\$0.0046	\$0.0046	\$0.0046	
185																	
186																	
187																	
188																	
189	<b>Total Interest</b>	In 46 + 112 + 174	\$ -	\$ 2,252	\$ 500	\$ 523	\$ 1,936	\$ 3,245	\$ 4,774	\$ (475)	\$ 5,766	\$ 18,889	\$ 13,700	\$ 3,218	\$ (10,244)	\$ -	\$ 44,085

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty

3 Peak 2021 - 2022 Winter Cost of Gas Filing

4 Adjustments to Gas Costs

5

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Updated Schedule 4

Page 1 of 1

6	Adjustments	Prior Period Adjustments	Refunds from Suppliers	Broker Revenue	Inventory Finance Charges	Transportation CGA Revenues (Schedule 17)	Interruptible Sales Margin	Off System Sales Margin	Capacity Release	Net Option Premiums	Fixed Price Option Administrative Costs	Total Adjustments
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8												
9	May-20	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -			\$ -	\$ -	\$ -
10	Jun-20	-	-	-	-	-	-			-	-	-
11	Jul-20 1/	-	-	-	-	-	-			-	-	-
12	Aug-20 1/	-	-	-	-	-	-			-	-	-
13	Sep-20 1/	-	-	-	-	-	-			-	-	-
14	Oct-20 1/	-	-	-	-	-	-			-	-	-
15	Nov-20 1/	-	-	(47)	-	(1,032)	-			-	36,800	(243,108)
16	Dec-20 1/	-	-	(624)	-	(1,276)	-			-	-	(283,455)
17	Jan-21 1/	-	-	(751)	-	(1,436)	-			-	-	(283,617)
18	Feb-21 1/	-	-	(816)	-	(1,199)	-			-	-	(282,374)
19	Mar-21 1/	-	-	(757)	-	(1,145)	-			-	-	(279,025)
20	Apr-21 1/	-	-	(605)	-	(851)	-			-	-	(278,672)
21												
22	Subtotal May 20 - Oct 20	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23												
24	Subtotal Nov 20 - Apr 21	\$ -	\$ -	\$ (3,600)	\$ -	\$ (6,938)	\$ -	\$ -	\$ (1,676,512)	\$ -	\$ 36,800	\$ (1,650,251)
25												
26	Total Peak Period	\$ -	\$ -	\$ (3,600)	\$ -	\$ (6,938)	\$ -	\$ -	\$ (1,676,512)	\$ -	\$ 36,800	\$ (1,650,251)
27												

1/ Estimates are based on prior years actual, except transportation revenue is calculated on Schedule 17. and Inventory Finance Charges for Nov 20 - Apr 21 calculated on Schedule 16

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 Peak 2021 - 2022 Winter Cost of Gas Filing  
 4 Demand Costs

REDACTED  
 Updated Schedule 5A  
 Page 1 of 1

			Deferred to Peak								Peak Nov-Apr Total
	(a)	Peak (b)	Reference (c)	May 20 -Oct 20 (d)	Nov-21 (e)	Dec-21 (f)	Jan-22 (g)	Feb-22 (h)	Mar-22 (i)	Apr-22 (j)	(k)
11 Supply											
12 Niagara Supply			Sch 5B, In 9 * Sch 5C In 9 x days								
13 Subtotal Supply Demand & Reservation Charges											
14											
15 Pipeline											
16 Iroquois Gas Trans Service RTS 470-0			Sch 5B, In 12 * Sch 5C In 12 x days								
17 Tenn Gas Pipeline 95346 Z5-Z6			Sch 5B, In 13 * Sch 5C In 14 x days								
18 Tenn Gas Pipeline 2302 Z5-Z6			Sch 5B, In 14 * Sch 5C In 16 x days								
19 Tenn Gas Pipeline 8587 Z0-Z6			Sch 5B, In 15 * Sch 5C In 18 x days								
20 Tenn Gas Pipeline 8587 Z1-Z6			Sch 5B, In 16 * Sch 5C In 20 x days								
21 Tenn Gas Pipeline 8587 Z4-Z6			Sch 5B, In 17 * Sch 5C In 22 x days								
22 Tenn Gas Pipeline (Dracut) 42076 Z6-Z6 peak			Sch 5B, In 18 * Sch 5C In 24 x days								
23 Tenn Gas Pipeline (Dracut) 358905 Z6-Z7 peak			Sch 5B, In 19 * Sch 5C In 25 x days								
24 Tenn Gas Pipeline (Concord Lateral) Z6-Z6 peak			Sch 5B, In 20 * Sch 5C In 28 x days								
25 Portland Natural Gas Trans Service			Sch 5B, In 21 * Sch 5C In 30 x days								
26 Portland Natural Gas			Sch 5B, In 22 * Sch 5C In 31 x days								
27 ANE (TransCanada via Union to Iroquois)			Sch 5B, In 23 * Sch 5C In 32 x days								
28 TransCanada via Union to Portland			Sch 5B, In 24 * Sch 5C In 33 x days								
29 Tenn Gas Pipeline Z4-Z6 stg 632 peak			Sch 5B, In 25 * Sch 5C In 34 x days								
30 Tenn Gas Pipeline Z4-Z6 stg 11234 peak			Sch 5B, In 26 * Sch 5C In 36 x days								
31 Tenn Gas Pipeline Z5-Z6 stg 11234 peak			Sch 5B, In 27 * Sch 5C In 38 x days								
32 National Fuel FST 2358 peak			Sch 5B, In 28 * Sch 5C In 40 x days								
33											
34 Subtotal Pipeline Demand Charges				\$ 3,900,053	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 1,609,874	\$ 13,559,298
35											
36 Peaking Supply											
37 Tenn Gas Pipeline (Concord Lateral) Z6-Z6 peak			Sch 5B, In 31 * Sch 5C In 28 x days								
38 Demand FLS peak			Per Contract								
39 Constellation Demand peak			Per Contract								
40 Subtotal Peaking Demand Charges				\$ -	\$ 823,800	\$ 823,800	\$ 823,800	\$ 823,800	\$ 823,800	\$ -	\$ 4,119,000
41											
42 Subtotal Supply, Pipeline & Peaking			In 13 + In 34 + In 40	\$ 3,900,053	\$ 2,433,674	\$ 2,433,674	\$ 2,433,674	\$ 2,433,674	\$ 2,433,674	\$ 1,609,874	\$ 17,678,298
43											
44 Less Transportation Capacity Credit				\$ (1,320,558)	\$ (613,043)	\$ (613,043)	\$ (613,043)	\$ (613,043)	\$ (613,043)	\$ (405,527)	\$ (4,791,298)
45											
46 Total Supply, Pipeline & Peaking Demand				\$ 2,579,495	\$ 1,820,632	\$ 1,820,632	\$ 1,820,632	\$ 1,820,632	\$ 1,820,632	\$ 1,204,347	\$ 12,887,000
47											
48											
49 Dominion - Demand peak			Sch 5B, In 36 * Sch 5C In 64 x days	\$ 10,488	\$ 1,748	\$ 1,748	\$ 1,748	\$ 1,748	\$ 1,748	\$ 1,748	\$ 20,977
50 Dominion - Storage peak			Sch 5B, In 37 * Sch 5C In 65 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
51 Honeoye - Demand peak			Sch 5B, In 38 * Sch 5C In 68 x days	50,105	8,351	8,351	8,351	8,351	8,351	8,351	100,211
52 National Fuel - Demand peak			Sch 5B, In 40 * Sch 5C In 70 x days	96,318	16,053	16,053	16,053	16,053	16,053	16,053	192,636
53 National Fuel - Capacity peak			Sch 5B, In 41 * Sch 5C In 71 x days	191,580	31,930	31,930	31,930	31,930	31,930	31,930	383,161
54 Tenn Gas Pipeline - Demand peak			Sch 5B, In 42 * Sch 5C In 74 x days	171,615	28,603	28,603	28,603	28,603	28,603	28,603	343,230
55 Tenn Gas Pipeline - Capacity peak			Sch 5B, In 43 * Sch 5C In 75 x days	167,586	27,931	27,931	27,931	27,931	27,931	27,931	335,172
56											
57 Subtotal Storage Demand Costs				\$ 696,628	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 1,393,257
58											
59 Less Transportation Capacity Credit				\$ (235,878)	\$ (29,247)	\$ (29,247)	\$ (29,247)	\$ (29,247)	\$ (29,247)	\$ (29,247)	\$ (411,359)
60											
61 Total Storage Demand Costs			In 57 + In 59	\$ 460,750	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 86,858	\$ 981,898
62											
63 Total Demand Charges			In 42 + In 57	\$ 4,596,681	\$ 2,549,779	\$ 2,549,779	\$ 2,549,779	\$ 2,549,779	\$ 2,549,779	\$ 1,725,979	\$ 19,071,554
64											
65 Total Transportation Capacity Credit			In 44 + In 59	\$ (1,556,436)	\$ (642,289)	\$ (642,289)	\$ (642,289)	\$ (642,289)	\$ (642,289)	\$ (434,774)	\$ (5,202,657)
66											
67 Total Demand Charges less Cap. Cr.			In 63 + In 65	\$ 3,040,245	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,907,490	\$ 1,291,205	\$ 13,868,897
68											
69											

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**  
2 **d/b/a Liberty**  
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**  
4 **Demand Volumes**

Updated Schedule 5B  
Page 1 of 1

	(a)	Peak (b)	Reference (c)	Nov-21 (d)	Dec-21 (e)	Jan-22 (f)	Feb-22 (g)	Mar-22 (h)	Apr-22 (i)
<b>Supply</b>									
	Niagara Supply			-	-	-	-	-	-
<b>Pipeline</b>									
	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
	Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
	Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
	Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
	Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
	Tenn Gas Pipeline	peak	42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Tenn Gas Pipeline	peak	358905 FTA Z6-Z6	40,000	40,000	40,000	40,000	40,000	40,000
	Tenn Gas Pipeline (Concord Lateral)	peak	Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
	Portland Natural Gas Trans Service		FT-208544	1,000	1,000	1,000	1,000	1,000	1,000
	Portland Natural Gas		FT 233320	5,000	5,000	5,000	5,000	5,000	5,000
	ANE (TransCanada via Union to Iroquois)		Dawn - Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	TransCanada via Union to Portland		Dawn -Parkway to Portland	5,077	5,077	5,077	5,077	5,077	5,077
	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
	National Fuel	peak	FST N02358	6,098	6,098	6,098	6,098	6,098	6,098
<b>Peaking</b>									
	Tenn Gas Pipeline (Concord Lateral)	peak		-	-	-	-	-	-
	Demand FLS	peak		3,000	3,000	3,000	3,000	3,000	-
	Peaking Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	-
<b>Storage</b>									
	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
	Honeoye - Capacity	peak	SS-NY	245,380	245,380	245,380	245,380	245,380	245,380
	National Fuel - Demand	peak	FSS-O02357	6,098	6,098	6,098	6,098	6,098	6,098
	National Fuel - Capacity Reservation	peak	FSS-O02357	670,800	670,800	670,800	670,800	670,800	670,800
	Tenn Gas Pipeline - Demand	peak	FS-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
	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

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty

3 Peak 2021 - 2022 Winter Cost of Gas Filing

4 Demand Rates

5

6 Tariff Rates

7

8 Supply

9 Niagara Supply

10

11 Pipeline

12 Iroquois Gas Trans Service RTS 470-01 \$ 5.2357 Forth Revised Sheet No. 4

13 Tenn Gas Pipeline 95346 Z5-Z6 \$ 6.2957 17th Rev Sheet No. 14

14 Tenn Gas Pipeline 2302 Z5-Z6 \$ 6.2957 17th Rev Sheet No. 14

15 Tenn Gas Pipeline 8587 Z0-Z6 \$ 20.3736 FT-A (Z0 - Z6)

16 Tenn Gas Pipeline 8587 Z1-Z6 \$ 18.0875 FT-A (Z1 - Z6)

17 Tenn Gas Pipeline 8587 Z4-Z6 \$ 7.1645 FT-A (Z4 - Z6)

18 TGP Dracut 42076 FTA Z6-Z6 \$ 4.1818 17th Rev Sheet No. 14

19 TGP Dracut 358905 FTA Z6-Z6 \$ 4.1818 17th Rev Sheet No. 14

20 TGP Concord Lateral Firm Transportatio \$ 12.2113 Per contract

21 Portland Natural Gas FT-208544 \$ 18.2633 Negot Dmd /CMDY=Part 4.1 V7

22 Portland Natural Gas FT 233320 \$ 22.8125 Negot Dmd /CMDY=Part 4.1 V7

23 Tenn Gas Pipeline 632 Z4-Z6 (stg) \$ 7.1645 17th Rev Sheet No. 14

24 Tenn Gas Pipeline 11234 Z4-Z6(stg) \$ 7.1645 17th Rev Sheet No. 14

25 Tenn Gas Pipeline 11234 Z5-Z6(stg) \$ 6.2957 17th Rev Sheet No. 14

26 National Fuel FST N02358 \$ 4.5274 4.010 Version 31.0.1 Pg 1

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Updated Schedule 5C

Page 1 of 2

	Nov-21 30 Unit Rate	Dec-21 31 Unit Rate	Jan-22 31 Unit Rate	Feb-22 28 Unit Rate	Mar-22 31 Unit Rate	Apr-22 30 Unit Rate	Nov - Apr 181 Avg Rate
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**1 Liberty Utilities (EnergyNorth Natural Gas) Corp.**

**2 d/b/a Liberty**

**3 Peak 2021 - 2022 Winter Cost of Gas Filing**

43	ANE	Union Gas	\$	3.6665																
44		TransCanada Pipelines Limited	\$	11.9842	Dawn - Parkway to Iroquois															
45		Delivery Pressure Demand Charge	\$	0.6083	Dawn - Parkway to Iroquois															
46		Sub Total Demand Charges	\$	16.2590																
47		Conversion rate GJ to MMBTU	\$	1.0551																
48		Conversion rate to US\$	\$	1.2589	1/0/1900															
49		Demand Rate/US\$	\$	13.6260		\$	0.4542	\$	0.4395	\$	0.4395	\$	0.4866	\$	0.4395	\$	0.4542	\$	0.4523	
50																				
51		Union Gas	\$	3.6665																
52		TransCanada Pipelines Limited	\$	20.4218	Dawn -Parkway to Portland															
53		Delivery Pressure Demand Charge	\$	0.6083	Dawn -Parkway to Portland															
54		Sub Total Demand Charges	\$	24.6966																
55		Conversion rate GJ to MMBTU	\$	1.0551																
56		Conversion rate to US\$	\$	1.2589	1/0/1900															
57		Demand Rate/US\$	\$	20.6972		\$	0.6899	\$	0.6677	\$	0.6677	\$	0.7392	\$	0.6677	\$	0.6899	\$	0.6870	
58																				
59	<b>Peaking</b>																			
60		Demand FLS																		
61		Subtotal Peaking Demand Charges																		
62																				
63	<b>Storage</b>																			
64		Dominion - Demand	GSS 300076	\$	1.8716	GSS Settled,Tariff Rec #10.30 \	\$	0.0624	\$	0.0604	\$	0.0604	\$	0.0668	\$	0.0604	\$	0.0624	\$	0.0621
65		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
66				\$	1.8861		\$	0.0629	\$	0.0608	\$	0.0608	\$	0.0674	\$	0.0608	\$	0.0629	\$	0.0626
67																				
68		Honeoye - Demand	SS-NY	\$	6.1299	Sub 1st Rev Sheet No. 5	\$	0.2043	\$	0.1977	\$	0.1977	\$	0.2189	\$	0.1977	\$	0.2043	\$	0.2033
69																				
70		National Fuel - Demand	FSS-O02357	\$	2.6325	4.020 Version 26.0.0 Pg 1	\$	0.0878	\$	0.0849	\$	0.0849	\$	0.0940	\$	0.0849	\$	0.0878	\$	0.0873
71		National Fuel - Capacity	FSS-O02357	\$	0.0476	4.020 Version 26.0.0 Pg 1	\$	0.0016	\$	0.0015	\$	0.0015	\$	0.0017	\$	0.0015	\$	0.0016	\$	0.0016
72				\$	2.6801		\$	0.0893	\$	0.0865	\$	0.0865	\$	0.0957	\$	0.0865	\$	0.0893	\$	0.0889
73																				
74		Tenn Gas Pipeline	FS-MA 523	\$	1.3094	20th Rev Sheet No.61	\$	0.0436	\$	0.0422	\$	0.0422	\$	0.0468	\$	0.0422	\$	0.0436	\$	0.0434
75		Tenn Gas Pipeline - Space	FS-MA 523	\$	0.0179	20th Rev Sheet No.61	\$	0.0006	\$	0.0006	\$	0.0006	\$	0.0006	\$	0.0006	\$	0.0006	\$	0.0006
76				\$	1.3273		\$	0.0442	\$	0.0428	\$	0.0428	\$	0.0474	\$	0.0428	\$	0.0442	\$	0.0440
77																				
78																				

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FEDERAL ENERGY REGULATORY COMMISSION  
WASHINGTON, D.C. 20426

FY 2021 GAS ANNUAL CHARGES  
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE  
June 16, 2021

The annual charges unit charge (ACA) to be applied to in fiscal year 2022 for recovery of FY 2021 Current year and 2020 True-Up is **\$0.0012** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2021.

The following calculations were used to determine the FY 2021 unit charge:

**2021 CURRENT:**

Estimated Program Cost \$73,470,000 divided by 61,333,716,267 Dth = 0.0011978730

**2020 TRUE-UP:**

Debit/Credit Cost (\$1,115,938) divided by 60,594,054,316 Dth = (0.0000184166)

**TOTAL UNIT CHARGE** = 0.0011794564

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

PUBLIC

Eastern Gas Transmission and Storage, Inc.  
FERC Gas Tariff  
Sixth Revised Volume No. 1

GSS, GSS-E & ISS Rates - Settled Parties  
Tariff Record No. 10.30  
Version 1.0.0  
Superseding Version 0.0.0

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)
[4], [4]	Storage Demand	\$1.7084	\$0.0673	\$0.0073	(\$0.0022)	\$0.0008	\$1.8716	-
	Storage Capacity	\$0.0145	-	-	-	-	\$0.0145	-
	Injection Charge	\$0.0154	-	\$0.0120	\$0.0000	(\$0.0007)	\$0.0267	-
	Withdrawal Charge	\$0.0154	-	-	\$0.0000	(\$0.0007)	\$0.0147	[8]
	GSS-TE Surcharge [3]	-	\$0.0047	-	\$0.0006	-	\$0.0053	-
	From Customers Balance	\$0.6163	\$0.0144	\$0.0016	(\$0.0006)	(\$0.0005)	\$0.6313	[8]
[4], [4]	Storage Demand	\$2.2113	\$0.0673	\$0.0073	(\$0.0022)	\$0.0008	\$2.2845	-
	Storage Capacity	\$0.0369	-	-	-	-	\$0.0369	-
	Injection Charge	\$0.0154	-	\$0.0120	\$0.0000	(\$0.0007)	\$0.0267	-
	Withdrawal Charge	\$0.0154	-	-	\$0.0000	(\$0.0007)	\$0.0147	[8]
	Authorized Overruns	\$1.0657	\$0.0144	\$0.0016	(\$0.0006)	(\$0.0005)	\$1.0807	[8]
[2]	ISS Capacity	\$0.0736	\$0.0022	\$0.0002	(\$0.0001)	\$0.0000	\$0.0759	-
	Injection Charge	\$0.0154	-	\$0.0120	\$0.0000	(\$0.0007)	\$0.0267	-
	Withdrawal Charge	\$0.0154	-	-	\$0.0000	(\$0.0007)	\$0.0147	[8]
	Authorized Overrun/From Cust. Bal	\$0.6163	\$0.0144	\$0.0016	(\$0.0006)	(\$0.0005)	\$0.6313	[8]
	Excess Injection Charge	\$0.2245	-	\$0.0120	\$0.0000	(\$0.0007)	\$0.2358	-

- [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 5.1.0.
- [4] Daily Capacity Release Rate for GSS per Dt is \$0.6166. Daily Capacity Release Rate for GSS-E per Dt is \$1.0660.
- [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 (<https://www.ferc.gov/industries-data/natural-gas/overview/general-information/annual-charges>).



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/	
- PXP Project	\$00.0091		
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 FACTOR-LAUF:

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

MEASUREMENT VARIANCE FACTOR-FUEL 3/

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](http://www.ferc.gov)) is incorporated herein by reference.

SCHEDULE 1

Receipt Point: 01-0100 Pittsburg, NH  
Delivery Point: 02-0260 Berlin, NH  
Maximum Daily Quantity: 1000 Dth/day  
Maximum Contract Demand: 5478000 Dth  
Effective Service Period: Beginning on the In-Service Date as defined in Article VII to this Contract and continuing in full force and effect until fifteen (15) years after such In-Service Date.

Rate Provision(s) (check if applicable rate):

Discounted Rate

Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

\$18.2633/Dth/month (\$0.6000/Dth/day)

Additional Terms: Shipper shall have the right to deliver, on a secondary basis, to the following meters, at the Negotiated Rate of \$18.2633/Dth/month (\$0.6000/Dth/day). Delivery to all other secondary delivery points on this Negotiated Rate contract shall be priced at the Maximum Recourse Rate.

Meter #	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-0725	Eliot	Granite State
05-0750	Eliot CNG	XPress Natural Gas
02-0775	Newington	Essential Power
02-0900	Newington	Eversource Energy
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1025	Haverhill	National Grid
05-1050	Methuen	M&NE
05-1150	Dracut	Tennessee Gas Pipeline

Revision No. 2

SCHEDULE 1

Primary Receipt Points

<u>Begin Date</u>	<u>End Date</u>	<u>Scheduling Point No.</u>	<u>Scheduling Point Name</u>	Maximum Daily Quantity (Dth/day)
1/	1/	10100	Pittsburg (East Hereford)	1,855 (Phase I Quantity) plus 2,577 (Phase II Quantity) plus 568 (Phase III Quantity)

Primary Delivery Points

<u>Begin Date</u>	<u>End Date</u>	<u>Scheduling Point No.</u>	<u>Scheduling Point Name</u>	Maximum Daily Quantity (Dth/day)
1/	1/	51150	Dracut	1,855 (Phase I Quantity) plus 2,577 (Phase II Quantity) plus 568 (Phase III Quantity)

Maximum Contract Demand	1,855 Dth (Phase I Quantity)
plus	2,577 Dth (Phase II Quantity)
plus	568 Dth (Phase III Quantity)
Total Maximum Contract Demand	5,000 Dth (Phase I, II and III Quantities)
Effective Service Period 1/	to 1/

Rate Provision(s) (check if applicable rate):

Discounted Rate  
 Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

For volumes received at the primary receipt point and delivered to the primary delivery point, the reservation charge shall be \$0.7500/Dth/day (the "Negotiated Daily Demand Rate").

CURRENTLY EFFECTIVE RATES

**FIRM STORAGE SERVICE (FSS)\***

	RATE	UNITS
1. Reservation Rate		
Deliverability Reservation Rate	Market Based/ Negotiable	
Capacity Reservation Rate	Market Based/ Negotiable	
2. Injection/Withdrawal Rates		
Injection Rate	Market Based/ Negotiable	
Overrun Injection Rate	Market Based/ Negotiable	
Late Withdrawal Rate	\$1/Dth/Day	
Overrun Withdrawal Rate	Market Based/ Negotiable	

\*All quantities of natural gas are measured in dekatherms (Dth)

### View Contract

#### General Information

Customer Energy North Natural Gas Inc	Contract Category Storage	Contract Number EN-11234	Service Type FT	Status Active	Currency USD
Deal Maker Richard Norman	Deal Date 01/17/1998	Deal Time (hh:mm) 08:00	Master Agreement - None -	Units Dth	
Contact Name Sarah Finnegan	Contact Number 1 803-2153569	Contact Number 2	Contact Email sarah.finnegan@nbergyutilities.com		

#### Contract Dates

Effective Date (First Gas Day) 05/01/2010	Termination Date (Last Gas Day) 01/01/2050
--	---

#### Nomination Deadlines

Day Before Flow Deadline (within 24-hr CCT)	Day of Flow Deadline (within 24-hr CCT)
--	--

#### Transaction Types and Rates

Transaction Type	Allow Transaction			Use Hourly Profiles	Volumetric Charge (\$/Dth)	Other Rate (\$/Dth)	Fuel Percentage	Invoice Qty Type
	Yes	No	D.S.R. Only					
Storage Injection	<input checked="" type="radio"/>	<input type="radio"/>	<input type="radio"/>	<input type="checkbox"/>	0	0	0	Sch Qty
Storage Withdrawal	<input checked="" type="radio"/>	<input type="radio"/>	<input type="radio"/>	<input type="checkbox"/>	0	0	0	Sch Qty
Authorized Injection Overrun	<input checked="" type="radio"/>	<input type="radio"/>	<input type="radio"/>	<input type="checkbox"/>	0	0	0	Sch Qty
Authorized Withdrawal Overrun	<input checked="" type="radio"/>	<input type="radio"/>	<input type="radio"/>	<input type="checkbox"/>	0	0	0	Sch Qty

#### Storage and Other Rates

<input type="checkbox"/> Use Monthly Flat Storage Fee (\$/Month)	Monthly Flat Storage Fee Table		
	From 05/01/10	To 01/01/50	Rate 8,350.00000

#### FERC Information

Capacity Release Contract: <input type="radio"/> Yes <input checked="" type="radio"/> No	Award:
Shopper Affiliation: NONE	Negotiated Rate Indicator: <input checked="" type="radio"/> Yes <input type="radio"/> No
Maximum Tariff Rate: <input checked="" type="radio"/> CR <input type="radio"/> Market Based Rates	Rate Schedule: 157

#### Contract Quantity Limits

Monthly MSQ Table			
From 05/01/10	To 01/01/50	Max Qty 245,280	Min Qty 0

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

Fourth Revised Sheet No. 4  
Superseding  
Third Revised Sheet No. 4

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

	Minimum	RP16-301 Rates 2/ Maximum			RP19-445 Rates Maximum	
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018	Effective 3/1/2019	Effective 4/1/2020
RTS DEMAND (Monthly):						
Zone 1	\$0.0000	\$ 6.1928	\$ 5.9982	\$ 5.5997	\$5.4177	\$5.2357
Zone 2	\$0.0000	\$ 5.3381	\$ 5.1678	\$ 4.7998	\$4.6438	\$4.4878
Inter-Zone	\$0.0000	\$10.4755	\$ 9.8672	\$ 8.8026	\$8.5165	\$8.2304
RTS COMMODITY (Daily):						
Zone 1	\$0.0034	\$ 0.0034	\$ 0.0034	\$ 0.0034	\$0.0034	\$0.0034
Zone 2	\$0.0022	\$ 0.0022	\$ 0.0022	\$ 0.0022	\$0.0022	\$0.0022
Inter-Zone	\$0.0056	\$ 0.0056	\$ 0.0056	\$ 0.0056	\$0.0056	\$0.0056
ITS COMMODITY (Daily):						
Zone 1	\$0.0034	\$ 0.2070	\$ 0.2006	\$ 0.1875	\$0.1815	\$0.1755
Zone 2	\$0.0022	\$ 0.1777	\$ 0.1721	\$ 0.1600	\$0.1549	\$0.1497
Inter-Zone	\$0.0056	\$ 0.3500	\$ 0.3300	\$ 0.2950	\$0.2856	\$0.2762
VOLUMETRIC CAPACITY RELEASE (Daily) 3/:						
Zone 1	\$0.0000	\$ 0.2036	\$ 0.1972	\$ 0.1841	\$0.1781	\$0.1721
Zone 2	\$0.0000	\$ 0.1755	\$ 0.1699	\$ 0.1578	\$0.1527	\$0.1475
Inter-Zone	\$0.0000	\$ 0.3444	\$ 0.3244	\$ 0.2894	\$0.2800	\$0.2706

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

(Footnotes continued on Sheet 4.01)

Issued On: June 12, 2019

Effective On: July 1, 2019

National Fuel Gas Supply Corporation  
FERC Gas Tariff  
Fifth Revised Volume No. 1

Part 4 - Applicable Rates  
§ 4.010 - Transportation Rates  
Version 31.0.0  
Page 1 of 1

**RATES FOR TRANSPORTATION SERVICES**

Rate Sch. (1)	Rate Component <sup>1/</sup> (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	Current Rate <sup>2/</sup> (6)
FT/FT-S	Reservation	(Max)	\$4.5019	-	-	\$4.5019 <sup>4/</sup>
		(Min)	0.0000	-	-	\$0.0000
	Commodity	(Max)	0.0140	-	-	\$0.0140 plus ACA <sup>3/</sup>
		(Min)	0.0140	-	-	\$0.0140 plus ACA <sup>3/</sup>
	Overrun	(Max)	0.1620	-	-	\$0.1620 plus ACA <sup>3/</sup>
		(Min)	0.0140	-	-	\$0.0140 plus ACA <sup>3/</sup>
EFT	Reservation	(Max)	\$4.6455	0.0000	0.0000	\$4.6455 <sup>4/</sup>
		(Min)	0.0000	0.0000	0.0000	\$0.0000
	Commodity	(Max)	0.0148	0.0000	0.0000	\$0.0148 plus ACA <sup>3/</sup>
		(Min)	0.0148	0.0000	0.0000	\$0.0148 plus ACA <sup>3/</sup>
	Overrun	(Max)	0.1675	-	-	\$0.1675 plus ACA <sup>3/</sup>
		(Min)	0.0148	-	-	\$0.0148 plus ACA <sup>3/</sup>
FST	Reservation	(Max)	\$4.5019	-	-	\$4.5019 <sup>4/</sup>
		(Min)	0.0000	-	-	\$0.0000
	Commodity	(Max)	0.0140	-	-	\$0.0140 plus ACA <sup>3/</sup>
		(Min)	0.0140	-	-	\$0.0140 plus ACA <sup>3/</sup>
	Overrun	(Max)	0.1620	-	-	\$0.1620 plus ACA <sup>3/</sup>
		(Min)	0.0140	-	-	\$0.0140 plus ACA <sup>3/</sup>
IT	Commodity	(Max)	\$0.1620	-	-	\$0.1620 plus ACA <sup>3/</sup>
		(Min)	0.0000	-	-	\$0.0000 plus ACA <sup>3/</sup>
	Overrun	(Max)	0.1620	-	-	\$0.1620 plus ACA <sup>3/</sup>
		(Min)	0.0000	-	-	\$0.0000 plus ACA <sup>3/</sup>

The NA15 Retention is 1.11% applicable to use of the Northern Access 2015 Lease.<sup>2/ 3/</sup>

- 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 0.84% and the Transportation LAUF Retention for all applicable rate schedules is 0.53%. 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, a per Dth charge of \$0.0255 shall be added as a Transmission PS/GHG Surcharge, in addition to the specified rate.

Effective On: April 1, 2021

**RATES FOR PART 284 STORAGE SERVICES**

Rate Sch. (1)	Rate Component <sup>2/</sup> (2)		Rate <sup>2/</sup> (3)
ESS	Demand	(Max)	\$2.6433 <sup>5/</sup>
		(Min)	\$0.0000
	Capacity	(Max)	\$0.0485 <sup>6/</sup>
		(Min)	\$0.0000
	Injection/Withdrawal	(Max)	\$0.0458 plus ACA <sup>3/</sup>
	(Min)	\$0.0000	
	Storage Balance Transfer	(Max) <sup>4/</sup>	\$3.8600
		(Min) <sup>4/</sup>	\$0.0000
ISS	Injection	(Max)	\$1.1271 plus ACA <sup>3/</sup>
		(Min)	\$0.0000
	Storage Balance Transfer	(Max) <sup>4/</sup>	\$3.8600
(Min) <sup>4/</sup>		\$0.0000	
FSS	Demand	(Max)	\$2.5326 <sup>5/</sup>
		(Min)	\$0.0000
	Capacity	(Max)	\$0.0462 <sup>6/</sup>
		(Min)	\$0.0000
	Injection/Withdrawal	(Max)	\$0.0459 plus ACA <sup>3/</sup>
	(Min)	\$0.0000	
	Storage Balance Transfer	(Max) <sup>4/</sup>	\$3.8600
		(Min) <sup>4/</sup>	\$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 1.06%.
- 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/ Rate per nomination.
- 5/ Pursuant to Section 42 of the General Terms and Conditions, a per Dth charge of \$0.0999 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.
- 6/ Pursuant to Section 42 of the General Terms and Conditions, a per Dth charge of \$0.0014 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

Effective On: April 1, 2021



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

Seventeenth Revised Sheet No. 14  
Superseding  
Sixteenth Revised Sheet No. 14

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	\$4.8571		\$10.1498	\$13.6529	\$13.8945	\$15.2673	\$16.2055	\$20.3323
	L		\$4.3119						
	1	\$7.3119		\$7.0090	\$9.3276	\$13.2135	\$13.0132	\$14.6759	\$18.0462
	2	\$13.6530		\$9.2716	\$4.8222	\$4.5078	\$5.7679	\$7.9331	\$10.2407
	3	\$13.8945		\$7.3440	\$4.8611	\$3.5070	\$5.3870	\$9.7428	\$11.2581
	4	\$17.6413		\$16.2638	\$6.1979	\$9.4190	\$4.6105	\$4.9861	\$7.1232
	5	\$21.0347		\$14.7807	\$6.5015	\$7.8669	\$5.1218	\$4.8044	\$6.2544
	6	\$24.3333		\$16.9768	\$11.6840	\$12.8717	\$9.0920	\$4.7831	\$4.1405

Daily Base Reservation Rate 1/	RECEIPT ZONE	DELIVERY ZONE							
		0	L	1	2	3	4	5	6
	0	\$0.1597		\$0.3337	\$0.4489	\$0.4568	\$0.5019	\$0.5328	\$0.6685
	L		\$0.1418						
	1	\$0.2404		\$0.2304	\$0.3067	\$0.4344	\$0.4278	\$0.4825	\$0.5933
	2	\$0.4489		\$0.3048	\$0.1585	\$0.1482	\$0.1896	\$0.2608	\$0.3367
	3	\$0.4568		\$0.2414	\$0.1598	\$0.1153	\$0.1771	\$0.3203	\$0.3701
	4	\$0.5800		\$0.5347	\$0.2038	\$0.3097	\$0.1516	\$0.1639	\$0.2342
	5	\$0.6916		\$0.4859	\$0.2137	\$0.2586	\$0.1684	\$0.1580	\$0.2056
	6	\$0.8000		\$0.5581	\$0.3841	\$0.4232	\$0.2999	\$0.1573	\$0.1361

Maximum Reservation Rates 2/, 3/	RECEIPT ZONE	DELIVERY ZONE							
		0	L	1	2	3	4	5	6
	0	\$4.8984		\$10.1911	\$13.6942	\$13.9358	\$15.3086	\$16.2468	\$20.3736
	L		\$4.3532						
	1	\$7.3532		\$7.0503	\$9.3689	\$13.2548	\$13.0545	\$14.7172	\$18.0875
	2	\$13.6943		\$9.3129	\$4.8635	\$4.5491	\$5.8092	\$7.9744	\$10.2820
	3	\$13.9358		\$7.3853	\$4.9024	\$3.5483	\$5.4283	\$9.7841	\$11.2994
	4	\$17.6826		\$16.3051	\$6.2392	\$9.4603	\$4.6518	\$5.0274	\$7.1645
	5	\$21.0760		\$14.8220	\$6.5428	\$7.9082	\$5.1631	\$4.8457	\$6.2957
	6	\$24.3746		\$17.0181	\$11.7253	\$12.9130	\$9.1333	\$4.8244	\$4.1818

Notes:

- 1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
- 2/ Includes a per Dth charge for the PCB Surchage Adjustment per Article XXXII of the General Terms and Conditions of \$0.0000.
- 3/ Includes a per Dth charge for the PS/GHGSurchage Adjustment per Article XXXVIII of the General Terms and Conditions of \$0.0413.

Issued: September 30, 2020  
Effective: November 1, 2020

Docket No. RP20-1253-000  
Accepted: October 29, 2020

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

Twenty Sixth Revised Sheet No. 19  
Superseding  
Twenty Fifth Revised Sheet No. 19

FIRM TRANSPORTATION RATES  
RATE SCHEDULE FT-A

Recourse Rates Applicable to Shippers Utilizing Capacity  
Pursuant to Incremental Capacity Expansions

	Base Tariff Rate	Total Rate
<b>C P00-65 300 Line Expansion</b>		
Reservation Charge:		
Maximum	\$3.2691	\$3.3104 1/, 4/
Minimum	\$0.0000	\$0.0000
Commodity Charge:		
Maximum	\$0.0000	\$0.0016 2/, 3/, 4/
Minimum	\$0.0000	\$0.0000 2/, 3/
<b>C P05-355 Northeast Corridor - New York/New Jersey Expansion</b>		
Reservation Charge:		
Maximum	\$9.1876	\$9.2289 1/, 4/
Minimum	\$0.0000	\$0.0000
Commodity Charge:		
Maximum	\$0.0000	\$0.0016 2/, 3/, 4/
Minimum	\$0.0000	\$0.0000 2/, 3/
<b>C P08-65 Concord Expansion</b>		
Reservation Charge:		
Maximum	\$10.8352	\$10.8765 1/, 4/
Minimum	\$0.0000	\$0.0000
Commodity Charge:		
Maximum	\$0.0000	\$0.0016 2/, 3/, 4/
Minimum	\$0.0000	\$0.0000 2/, 3/
<b>C P09-444 300 Line Project - Market Component</b>		
Reservation Charge:		
Maximum	\$22.9057	\$22.9470 1/, 4/
Minimum	\$0.0000	\$0.0000
Commodity Charge:		
Maximum	\$0.0000	\$0.0016 2/, 3/, 4/
Minimum	\$0.0000	\$0.0000 2/, 3/
<b>C P11-30-000 Northeast Supply Diversification Project</b>		
Reservation Charge:		
Maximum	\$5.5453	\$5.5866 1/, 4/
Minimum	\$0.0000	\$0.0000
Commodity Charge:		
Maximum	\$0.0000	\$0.0016 2/, 3/, 4/, 5/
Minimum	\$0.0000	\$0.0000 2/, 3/, 5/
<b>C P11-36-000 Northampton Expansion Project</b>		
Reservation Charge:		
Maximum	\$24.7109	\$24.7522 1/, 4/
Minimum	\$0.0000	\$0.0000
Commodity Charge:		
Maximum	\$0.0000	\$0.0016 2/, 3/, 4/
Minimum	\$0.0000	\$0.0000 2/, 3/

Notes:

- 1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of \$0.0000.
- 2/ 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.
- 3/ 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.
- 4/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of \$0.0413 Reservation, \$0.0016 Commodity.
- 5/ Applicable fuel and lost and unaccounted for charges pursuant to the Dominion Lease.

Issued: September 30, 2020  
Effective: November 1, 2020

Docket No. RP20-1253-000  
Accepted: October 29, 2020

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

Seventeenth Revised Sheet No. 15  
Superseding  
Sixteenth 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	\$0.2391	\$0.2282	\$0.2716
L		\$0.0012						
1	\$0.0042		\$0.0081	\$0.0147	\$0.0179	\$0.2033	\$0.2073	\$0.2367
2	\$0.0167		\$0.0087	\$0.0012	\$0.0028	\$0.0658	\$0.1055	\$0.1169
3	\$0.0207		\$0.0169	\$0.0026	\$0.0002	\$0.0879	\$0.1217	\$0.1329
4	\$0.0250		\$0.0205	\$0.0087	\$0.0105	\$0.0407	\$0.0576	\$0.0932
5	\$0.0284		\$0.0256	\$0.0100	\$0.0118	\$0.0573	\$0.0567	\$0.0705
6	\$0.0346		\$0.0300	\$0.0143	\$0.0163	\$0.0881	\$0.0478	\$0.0290

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	\$0.0039		\$0.0122	\$0.0184	\$0.0226	\$0.2398	\$0.2289	\$0.2723
L		\$0.0019						
1	\$0.0049		\$0.0088	\$0.0154	\$0.0186	\$0.2040	\$0.2080	\$0.2374
2	\$0.0174		\$0.0094	\$0.0019	\$0.0035	\$0.0665	\$0.1062	\$0.1176
3	\$0.0214		\$0.0176	\$0.0033	\$0.0009	\$0.0886	\$0.1224	\$0.1336
4	\$0.0257		\$0.0212	\$0.0094	\$0.0112	\$0.0414	\$0.0583	\$0.0939
5	\$0.0291		\$0.0263	\$0.0107	\$0.0125	\$0.0580	\$0.0574	\$0.0712
6	\$0.0353		\$0.0307	\$0.0150	\$0.0170	\$0.0888	\$0.0485	\$0.0297

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 \$0.0007.

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

Twentieth Revised Sheet No. 61  
Superseding  
Nineteenth Revised Sheet No. 61

RATES PER DEKATHERM

Rate Schedule and Rate	FIRM STORAGE SERVICE RATE SCHEDULE FS			
	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
<b>FIRM STORAGE SERVICE (FS) - PRODUCTION AREA</b>				
Deliverability Rate	\$1.7824	\$1.7824 1/		
Space Rate	\$0.0181	\$0.0181 1/		
Injection Rate	\$0.0073	\$0.0073	1.62%	\$0.0000
Withdrawal Rate	\$0.0073	\$0.0073		
Overrun Rate	\$0.2139	\$0.2139 1/		
<b>FIRM STORAGE SERVICE (FS) - MARKET AREA</b>				
Deliverability Rate	\$1.3094	\$1.3094 1/		
Space Rate	\$0.0179	\$0.0179 1/		
Injection Rate	\$0.0087	\$0.0087	1.62%	\$0.0000
Withdrawal Rate	\$0.0087	\$0.0087		
Overrun Rate	\$0.1572	\$0.1572 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 0.03%.

Issued: March 1, 2021  
Effective: April 1, 2021

Docket No. RP21-552-000  
Accepted: March 31, 2021

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

Seventeenth Revised Sheet No. 32  
Superseding  
Sixteenth Revised Sheet No. 32

FUBLAND EPCR

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

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	0.43%		1.54%	2.34%	2.97%	3.59%	4.08%	4.66%
L		0.16%						
1	0.56%		1.09%	1.96%	2.43%	2.92%	3.55%	4.06%
2	2.40%		1.17%	0.15%	0.38%	0.79%	1.44%	1.96%
3	2.97%		2.37%	0.38%	0.03%	1.14%	1.67%	2.26%
4	3.46%		2.71%	1.16%	1.40%	0.40%	0.66%	1.22%
5	4.08%		3.55%	1.42%	1.67%	0.66%	0.65%	0.86%
6	4.88%		4.06%	1.96%	2.26%	1.14%	0.50%	0.20%

Broad Run Expansion Project – Market Component (Z3-Z1): 5/ 7.62%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0021		\$0.0081	\$0.0125	\$0.0155	\$0.0188	\$0.0214	\$0.0256
L		\$0.0007						
1	\$0.0028		\$0.0057	\$0.0104	\$0.0127	\$0.0157	\$0.0193	\$0.0221
2	\$0.0125		\$0.0061	\$0.0007	\$0.0018	\$0.0041	\$0.0074	\$0.0102
3	\$0.0155		\$0.0127	\$0.0018	\$0.0000	\$0.0060	\$0.0088	\$0.0118
4	\$0.0188		\$0.0145	\$0.0060	\$0.0074	\$0.0019	\$0.0034	\$0.0063
5	\$0.0214		\$0.0193	\$0.0074	\$0.0088	\$0.0013	\$0.0033	\$0.0044
6	\$0.0256		\$0.0221	\$0.0102	\$0.0118	\$0.0059	\$0.0025	\$0.0009

Broad Run Expansion Project – Market Component (Z3-Z1): 5/ \$0.0272

- 1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.00%.
- 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 0.00%.
- 3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, and FT.
- 4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
- 5/ The incremental F&LR and EPCR set forth above are applicable to a Shipper(s) utilizing capacity on the Broad Run Expansion Project – Market Component facilities, from any receipt point(s) to any delivery point(s) located on the project's transportation path. Any service provided to a Shipper(s) outside the project's transportation path shall be subject to the greater of the incremental F&LR and EPCR for the project or the applicable F&LR and EPCR for the applicable receipt(s) and delivery point(s) as shown in the rate matrices above. Included in the above F&LR is the Losses component of the F&LR equal to 0.00%.

Issued: March 1, 2021  
Effective: April 1, 2021

Docket No. RP21-552-000  
Accepted: March 31, 2021



Effective  
2021-07-01  
Rate M12  
Page 1 of 4

ENBRIDGE GAS INC.  
UNION SOUTH  
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 Commodity Charge Rate/GJ
<b><u>Firm Transportation (1), (5)</u></b>				
Dawn to Parkway	\$3.665	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	\$3.110			
Kirkwall to Parkway	\$0.555			
<b><u>M12-X Firm Transportation</u></b>				
Between Dawn, Kirkwall and Parkway	\$4.530	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".	
<b><u>Limited Firm/Interruptible Transportation (1)</u></b>				
Dawn to Parkway – Maximum	\$8.796	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	\$8.796			
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.165%	
<b><u>Carbon Charge (applied to all quantities transported)</u></b>				
Facility Carbon Charge		\$0.003	\$0.003	

**North Bay Junction Long Term Fixed Price (NBJ LTFF) Service**

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
1	NBJ LTFF	28.28750	0.9300
2	NBJ LTFF Differential Surcharge	0.00000	0.0000

Note: The toll for NBJ LTFF is inclusive of the applicable Abandonment Surcharge for FT service from Empress to North Bay Junction. The NBJ LTFF Differential Surcharge is zero provided the Abandonment Surcharge for FT service from Empress to North Bay Junction is equal or less than \$6.69167/GJ/Month.

**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)
3	Union Parkway Belt to Union EDA	9.92374	0.3262	0.44408	0.0146

**Delivery Pressure**

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
4	Average Delivery Pressure Toll	0.60833	0.0200

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 Injectors, IT, Diversions and STFT.

**Union Dawn Receipt Point Surcharge**

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
5	Union Dawn Receipt Point Surcharge	0.13135	0.0043

**Short Notice Balancing (SNB) Service**

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
6	SNB Toll	2.97597	0.0978

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)
7	Western Section	0.9982
8	Eastern Section	0.3302

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 for IT / STFT (\$/GJ)	Abandonment Surcharge (\$/GJ/Month)	Daily Equivalent Abandonment Surcharge (\$/GJ)
1	Union NDA	Enbridge CDA	-	0.4489	-	0.0220
2	Union NDA	Enbridge Parkway CDA	-	0.4544	-	0.0223
3	Union NDA	Enbridge EDA	-	0.4776	-	0.0239
4	Union NDA	KPUC EDA	-	0.5755	-	0.0307
5	Union NDA	Energir EDA	-	0.8356	-	0.0348
6	Union NDA	Enbridge SWDA	-	0.6022	-	0.0325
7	Union NDA	Union SWDA	-	0.6036	-	0.0326
8	Union NDA	Chippawa	-	0.5424	-	0.0284
9	Union NDA	Cornwall	-	0.5231	-	0.0271
10	Union NDA	East Hereford	-	0.7551	-	0.0430
11	Union NDA	Emerson 1	-	0.6495	-	0.0724
12	Union NDA	Emerson 2	-	0.6495	-	0.0724
13	Union NDA	Iroquois	-	0.5015	-	0.0256
14	Union NDA	Kirkwall	-	0.4793	-	0.0240
15	Union NDA	Naperville	-	0.6232	-	0.0339
16	Union NDA	Niagara Falls	-	0.5408	-	0.0283
17	Union NDA	North Bay Junction	-	0.1249	-	0.0063
18	Union NDA	Philpsburg	-	0.6346	-	0.0347
19	Union NDA	Spruce	-	0.5990	-	0.0660
20	Union NDA	St. Clair	-	0.6177	-	0.0336
21	Union NDA	Wefawyn	-	0.7378	-	0.0835
22	Union NDA	Dawn Export	-	0.6022	-	0.0325
23	Union Parkway Belt	Empress	38.33717	1.2604	3.89029	0.1279
24	Union Parkway Belt	TransGas SSOA	34.49250	1.1340	3.40667	0.1120
25	Union Parkway Belt	Centram SSOA	31.72763	1.0431	3.05688	0.1005
26	Union Parkway Belt	Centram MDA	29.00533	0.9536	2.71621	0.0893
27	Union Parkway Belt	Centrat MDA	29.57717	0.9724	2.66450	0.0876
28	Union Parkway Belt	Union WDA	24.64054	0.8101	2.04090	0.0671
29	Union Parkway Belt	Nipigon WDA	22.51746	0.7403	1.77329	0.0583
30	Union Parkway Belt	Union NDA	13.82133	0.4544	0.07829	0.0223
31	Union Parkway Belt	Calhock NDA	18.94350	0.6228	1.32313	0.0435
32	Union Parkway Belt	Tuna NDA	16.12996	0.5303	0.97029	0.0319
33	Union Parkway Belt	Energir NDA	13.74529	0.4519	0.66917	0.0220
34	Union Parkway Belt	Union SSMOA	16.07746	0.5483	1.16192	0.0382
35	Union Parkway Belt	Union NCOA	6.64604	0.2185	0.27983	0.0092
36	Union Parkway Belt	Union CDA	4.16100	0.1368	0.10650	0.0036
37	Union Parkway Belt	Union ECDA	3.47398	0.1142	0.06388	0.0021
38	Union Parkway Belt	Union EDA	9.02158	0.2966	0.44406	0.0146
39	Union Parkway Belt	Union Parkway Belt	2.92000	0.0960	0.02433	0.0008
40	Union Parkway Belt	Enbridge CDA	4.55946	0.1499	0.13668	0.0045
41	Union Parkway Belt	Enbridge Parkway CDA	2.92000	0.0960	0.02433	0.0008
42	Union Parkway Belt	Enbridge EDA	12.02007	0.3952	0.65992	0.0214
43	Union Parkway Belt	KPUC EDA	8.94250	0.2940	0.43800	0.0144
44	Union Parkway Belt	Energir EDA	15.63723	0.5141	0.89729	0.0295
45	Union Parkway Belt	Enbridge SWDA	7.41558	0.2438	0.33458	0.0110
46	Union Parkway Belt	Union SWDA	7.45817	0.2452	0.33763	0.0111
47	Union Parkway Belt	Chippawa	5.59667	0.1840	0.20683	0.0068
48	Union Parkway Belt	Cornwall	12.21838	0.4017	0.66306	0.0218
49	Union Parkway Belt	East Hereford	19.27504	0.6337	1.14671	0.0377
50	Union Parkway Belt	Emerson 1	27.28071	0.8969	2.49721	0.0821
51	Union Parkway Belt	Emerson 2	27.28071	0.8969	2.49721	0.0821
52	Union Parkway Belt	Iroquois	11.37888	0.3741	0.60529	0.0199
53	Union Parkway Belt	Kirkwall	3.67738	0.1209	0.07604	0.0025
54	Union Parkway Belt	Naperville	15.28004	0.5017	0.87296	0.0287
55	Union Parkway Belt	Niagara Falls	5.55104	0.1825	0.20379	0.0067
56	Union Parkway Belt	North Bay Junction	10.04358	0.3302	0.51404	0.0169
57	Union Parkway Belt	Philpsburg	15.60679	0.5131	0.89729	0.0295
58	Union Parkway Belt	Spruce	29.57717	0.9724	2.66450	0.0876
59	Union Parkway Belt	St. Clair	7.88704	0.2593	0.36500	0.0120
60	Union Parkway Belt	Wefawyn	31.72763	1.0431	3.05688	0.1005
61	Union Parkway Belt	Dawn Export	7.41558	0.2438	0.33458	0.0110
62	Union SSMOA	Empress	-	0.8516	-	0.0979
63	Union SSMOA	TransGas SSOA	-	0.7252	-	0.0819
64	Union SSMOA	Centram SSOA	-	0.6344	-	0.0705
65	Union SSMOA	Centram MDA	-	0.5448	-	0.0592
66	Union SSMOA	Centrat MDA	-	0.5385	-	0.0584
67	Union SSMOA	Union WDA	-	0.7145	-	0.0608
68	Union SSMOA	Nipigon WDA	-	1.0474	-	0.0877
69	Union SSMOA	Union NDA	-	0.8256	-	0.0597

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 Peak 2021 - 2022 Winter Cost of Gas Filing  
 4 Supply and Commodity Costs, Volumes and Rates

REDACTED  
 Updated Schedule 6  
 Page 1 of 5

5	6 For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
8									(i)
9	<b>Supply and Commodity Costs</b>								
10	<b>Pipeline Gas:</b>								
12	Dawn Supply	In 66 * In 107							
13	Niagara Supply	In 67 * In 112							
14	TGP Supply (Direct)	In 68 * In 132							
15	Dracut Supply 1 - Baseload	In 69 * In 117							
16	Dracut Supply 2 - Swing	In 70 * In 122							
17	Dracut Supply 3 - Swing	In 71 * In 123							
18	Constellation COMBO	In 72 * In 138							
19	LNG Truck	In 73 * In 140							
20	Propane Truck	In 74 * In 142							
21	PNGTS	In 75 * In 147							
22	Portland Natural Gas	In 76 * In 152							
23	TGP Supply (Z4)	In 77 * In 157							
24									
25	Subtotal Pipeline Gas Costs		\$ 6,488,894	\$ 25,785,739	\$ 19,058,558	\$ 11,866,845	\$ 7,408,521	\$ 3,274,803	\$ 73,883,360
26									
27	<b>Volumetric Transportation Costs</b>								
28	Dawn Supply	In 66 * In 204							
29	Niagara Supply	In 67 * In 215							
30	TGP Supply (Direct)	In 68 * In 242							
31	Dracut Supply 1 - Baseload	In 69 * In 263							
32	Dracut Supply 2 - Swing	In 70 * In 263							
33	Dracut Supply 3 - Swing	In 71 * In 264							
34	Constellation COMBO	In 72 * In 263							
35	TGP Storage - Withdrawals	In 82 * In 179							
36									
37	Total Volumetric Transportation Costs		\$ 288,190	\$ 216,647	\$ 275,048	\$ 239,882	\$ 238,945	\$ 59,504	\$ 1,318,217
38									
39	<b>Less - Gas Refill:</b>								
40	LNG Truck	In 91 * In 164							
41	Propane	In 92 * In 165							
42	TGP Storage Refill	In 93 * In 130							
43	Storage Refill (Trans.)	In 93 * In 242							
44									
45	Subtotal Refills		\$ (1,077,566)	\$ (15,566)	\$ (37,152)	\$ (1,041,646)	\$ (244,164)	\$ (434,450)	\$ (2,850,544)
46									
47	Total Supply & Pipeline Commodity Costs	In 25 + In 37 + In 45	\$ 5,699,518	\$ 25,986,820	\$ 19,296,454	\$ 11,065,081	\$ 7,403,303	\$ 2,899,858	\$ 72,351,034
48									
49	<b>Storage Gas:</b>								
50	TGP Storage - Withdrawals	In 82 * In 171	\$ 838,477	\$ 258,921	\$ 1,676,210	\$ 1,489,505	\$ 1,449,899	\$ 417,423	\$ 6,130,435
51									
52	<b>Produced Gas:</b>								
53	LNG Vapor	In 85 * In 159							
54	Propane	In 86 * In 161							
55									
56	Total Produced Gas	In 53 + In 54	\$ 14,924	\$ 296,153	\$ 644,056	\$ 1,138,771	\$ 190,796	\$ 14,685	\$ 2,299,384
57									
58									
59	Total Commodity Gas & Trans. Costs	In 47 + In 50 + In 56	\$ 6,552,919	\$ 26,541,893	\$ 21,616,721	\$ 13,693,357	\$ 9,043,998	\$ 3,331,966	\$ 80,780,853
60									\$ 94,216,591
61									

THIS PAGE HAS BEEN REDACTED

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
2 d/b/a Liberty  
3 Peak 2021 - 2022 Winter Cost of Gas Filing  
4 Supply and Commodity Costs, Volumes and Rates

Updated Schedule 6  
Page 2 of 5

5	6 For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
62									(i)
63	<b>Volumes (Therms)</b>								
64									
65	<b>Pipeline Gas:</b>	See Schedule 11A							
66	Dawn Supply		876,821	926,304	927,705	840,605	911,138	750,758	5,233,331
67	Niagara Supply		691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
68	TGP Supply (Direct)		4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346	17,283,547
69	Dracut Supply 1 - Baseload		-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
70	Dracut Supply 2 - Swing		1,775,785	5,569,137	771,324	-	969,754	79,714	9,165,713
71	Dracut Supply 3 - Swing		-	596,455	290,490	-	1,484	-	888,430
72	Constellation COMBO		89,306	231,576	1,424,042	1,188,519	1,411,967	-	4,345,410
73	LNG Truck		20,666	21,875	51,371	291,824	362,081	-	747,817
74	Propane Truck		-	-	-	695,072	-	-	695,072
75	PNGTS		219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
76	Portland Natural Gas		1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355	6,284,969
77	TGP Supply (Z4)		1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071	14,753,578
78									
79	Subtotal Pipeline Volumes		11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749	75,575,334
80									
81	<b>Storage Gas:</b>								
82	TGP Storage		2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
83									
84	<b>Produced Gas:</b>								
85	LNG Vapor		21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
86	Propane		-	-	244,014	574,010	-	-	818,023
87									
88	Subtotal Produced Gas		21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
89									
90	<b>Less - Gas Refill:</b>								
91	LNG Truck		(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-	(747,817)
92	Propane		-	-	-	(695,072)	-	-	(695,072)
93	TGP Storage Refill		(1,750,690)	-	-	-	-	(961,638)	(2,712,328)
94									
95	Subtotal Refills		(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
96									
97	<b>Total Sendout Volumes</b>		<b>12,149,289</b>	<b>18,516,267</b>	<b>21,514,739</b>	<b>17,827,032</b>	<b>15,332,053</b>	<b>8,877,211</b>	<b>94,216,591</b>
98									
99									
100									

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 Peak 2021 - 2022 Winter Cost of Gas Filing  
 4 Supply and Commodity Costs, Volumes and Rates

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 Updated Schedule 6  
 Page 3 of 6

5	6 For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
									(i)
101	<b>Gas Costs and Volumetric Transportation Rates</b>								
102									
103	<b>Pipeline Gas:</b>								
104	<b>Dawn Supply</b>								Average Rate
105	NYMEX Price	Sch 7, In 10/10							
106	Basis Differential								
107	<b>Net Commodity Costs</b>								
108									
109	<b>Niagara Supply</b>								
110	NYMEX Price	Sch 7, In 10/10							
111	Basis Differential								
112	<b>Net Commodity Costs</b>								
113									
114	<b>Dracut Supply 1 - Baseload</b>								
115	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10							
116	Basis Differential								
117	<b>Net Commodity Costs</b>								
118									
119	<b>Dracut Supply 2 - Swing</b>								
120	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10							
121	Basis Differential								
122	<b>Net Commodity Costs</b>								
123									
124	<b>Dracut Supply 3 - Swing</b>								
125	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10							
126	Basis Differential								
127	<b>Net Commodity Costs</b>								
128									
129	<b>TGP Supply (Direct)</b>								
130	NYMEX Price	Sch 7, In 10/10							
131	Basis Differential								
132	<b>Net Commodity Costs</b>								
133									
134									
135	<b>Constellation COMBO</b>								
136	NYMEX Price	Sch 7, In 10/10							
137	Basis Differential								
138	<b>Net Commodity Costs</b>								
139									
140	<b>LNG Truck</b>	Sch 7, In 10/10							
141									
142	<b>Propane Truck</b>	Propane WACOG							
143									
144	<b>PNGTS</b>								
145	NYMEX Price	Sch 7, In 10/10							
146	Basis Differential								
147	<b>Net Commodity Cost</b>								
148									
149	<b>PNGTS EXP</b>								
150	NYMEX Price	Sch 7, In 10/10							
151	Basis Differential								
152	<b>Net Commodity Cost</b>								
153									
154	<b>TGP Supply (Z4)</b>								
155	NYMEX Price	Sch 7, In 10/10							
156	Basis Differential								
157	<b>Net Commodity Cost</b>								
158									
159	<b>LNG Vapor (Storage)</b>	Sch 16, In 95 /10							
160									
161	<b>Propane</b>	Sch 16, In 66 /10							
162									
163	<b>Storage Refill:</b>								
164	<b>LNG Truck</b>	In 140							
165	<b>Propane</b>	In 142							
166									
167									

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 Peak 2021 - 2022 Winter Cost of Gas Filing  
 4 Supply and Commodity Costs, Volumes and Rates

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 Updated Schedule 6  
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5	6 For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
168									(i)
169									
170	<b>TGP Storage</b>								
171	<b>Commodity Costs - Storage withdrawal</b>	Sch 16, ln 34 /10	\$0.3046	\$0.3046	\$0.3046	\$0.3046	\$0.3046	\$0.3361	\$0.3098
172									
173	TGP - Max Commodity - Z 4-6	19th Rev Sheet No. 15	\$0.00928	\$0.00928	\$0.00928	\$0.00928	\$0.00928	\$0.00928	\$0.00928
174	TGP - Max Comm. ACA Rate - Z 4-6	19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
175	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		\$0.00940	\$0.00940	\$0.00940	\$0.00940	\$0.00940	\$0.00940	\$0.00940
176	TGP - Fuel Charge % - Z 4-6	17th Rev Sheet No. 32	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
177	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		\$0.00372	\$0.00372	\$0.00372	\$0.00372	\$0.00372	\$0.00410	\$0.00378
178	TGP - Withdrawal Charge	20th Rev Sheet No.61	\$0.00087	\$0.00087	\$0.00087	\$0.00087	\$0.00087	\$0.00087	\$0.00087
179	<b>Total Volumetric Transportation Rate - TGP (Storage)</b>		\$0.01399	\$0.01399	\$0.01399	\$0.01399	\$0.01399	\$0.01437	\$0.01405
180									
181	<b>Total TGP - Comm. &amp; Vol. Trans. Rate</b>	ln 171 + ln 179	\$0.31856	\$0.31856	\$0.31856	\$0.31856	\$0.31856	\$0.35044	\$0.32387
182									
183									
184	<b>Per Unit Volumetric Transportation Rates</b>								
185	<b>Dawn Supply Volumetric Transportation Charge</b>								
186	<b>Commodity Costs</b>	ln 107	\$0.5418	\$0.5718	\$0.5844	\$0.5888	\$0.5587	\$0.3978	\$0.5405
187									
188	TransCanada - Commodity Rate/GJ	Dawn - Parkway to Iroquois	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030
189	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
190	Conversion Rate to US\$	1/0/1900	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589
191	Commodity Rate/US\$	ln 188 x ln 189 x ln 190	\$0.00040	\$0.00040	\$0.00040	\$0.00040	\$0.00040	\$0.00040	\$0.00040
192	TransCanada Fuel %	Dawn - Parkway to Iroquois	0.97%	0.95%	1.20%	1.09%	0.97%	0.78%	0.99%
193	TransCanada Fuel * Percentage	ln 186 x ln 192	\$0.00524	\$0.00545	\$0.00702	\$0.00639	\$0.00540	\$0.00311	\$0.00544
194	Subtotal TransCanada		\$0.00564	\$0.00585	\$0.00742	\$0.00679	\$0.00580	\$0.00351	\$0.00583
195	IGTS - Z1 RTS Commodity	Forth Revised Sheet No. 4	\$0.00034	\$0.00034	\$0.00034	\$0.00034	\$0.00034	\$0.00034	\$0.00034
196	IGTS - Z1 RTS ACA Rate Commodity	Forth Revised Sheet No. 4	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
197	IGTS - Z1 RTS Deferred Asset Surcharge	Forth Revised Sheet No. 4	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
198	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		\$0.00046	\$0.00046	\$0.00046	\$0.00046	\$0.00046	\$0.00046	\$0.00046
199	TGP NET-NE - Comm. Segments 3 & 4	19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
200	IGTS -Fuel Use Factor - Percentage	Forth Revised Sheet No. 4	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
201	IGTS -Fuel Use Factor - Fuel * Percentage	ln 186 x ln 200	\$0.00542	\$0.00572	\$0.00584	\$0.00589	\$0.00559	\$0.00398	\$0.00541
202	TGP FTA Fuel Charge % Z 5-6	17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
203	TGP FTA Fuel * Percentage	ln 186 x ln 202	\$0.00466	\$0.00492	\$0.00503	\$0.00506	\$0.00480	\$0.00342	\$0.00465
204	<b>Total Volumetric Transportation Charge - Dawn Supply</b>		\$0.01630	\$0.01706	\$0.01887	\$0.01832	\$0.01677	\$0.01149	\$0.01647
205									
206									
207	<b>Niagara Supply Volumetric Transportation Charge</b>								
208	<b>Commodity Costs</b>	Ln 112							
209									
210	TGP FTA - FTA Z 5-6 Comm. Rate	19th Rev Sheet No. 15	\$0.00705	\$0.00705	\$0.00705	\$0.00705	\$0.00705	\$0.00705	\$0.00705
211	TGP FTA - FTA Z 5-6 - ACA Rate	19th Rev Sheet No. 15	\$0.00012	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001
212	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		\$0.00717	\$0.0072	\$0.0072	\$0.0072	\$0.0072	\$0.0072	\$0.0072
213	TGP FTA Fuel Charge % Z 5-6	17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
214	TGP FTA Fuel * Percentage	ln 208 x ln 213							
215	<b>Total Volumetric Transportation Rate - Niagara Supply</b>								
216									
217									

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 Peak 2021 - 2022 Winter Cost of Gas Filing  
 4 Supply and Commodity Costs, Volumes and Rates

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 Updated Schedule 6  
 Page 5 of 5

5	6 For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
									(i)
218									
219									
220									
221	<b>TGP Direct Volumetric Transportation Charge</b>								Average Rate
222	<b>Commodity Costs</b>								Ln 130
223									
224	TGP - Max Comm. Base Rate - Z 0-6	19th Rev Sheet No. 15	\$0.02672	\$0.02672	\$0.02672	\$0.02672	\$0.02672	\$0.02672	\$0.02672
225	TGP - Max Commodity ACA Rate - Z 0-6	19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
226	Subtotal TGP - Max Comm. Rate Z 0-6		\$0.02684	\$0.02684	\$0.02684	\$0.02684	\$0.02684	\$0.02684	\$0.02684
227	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
228	Prorated TGP - Max Commodity Rate - Z 0-6		\$0.00875	\$0.00875	\$0.00875	\$0.00875	\$0.00875	\$0.00875	\$0.00875
229	TGP - Max Comm. Base Rate - Z 1-6	19th Rev Sheet No. 15	\$0.02331	\$0.02331	\$0.02331	\$0.02331	\$0.02331	\$0.02331	\$0.02331
230	TGP - Max Commodity ACA Rate - Z 1-6	19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
231	Subtotal TGP - Max Commodity Rate - Z 1-6		\$0.02343	\$0.02343	\$0.02343	\$0.02343	\$0.02343	\$0.02343	\$0.02343
232	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
233	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		\$0.01579	\$0.01579	\$0.01579	\$0.01579	\$0.01579	\$0.01579	\$0.01579
234	TGP - Fuel Charge % - Z 0-6	17th Rev Sheet No. 32	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%
235	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
236	Prorated TGP Fuel Charge % - Z 0-6		1.52%	1.52%	1.52%	1.52%	1.52%	1.52%	1.52%
237	TGP - Fuel Charge % - Z 1-6	17th Rev Sheet No. 32	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
238	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
239	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
240	TGP - Fuel Charge % - Z 0-6	In 222 x In 236	\$0.00849	\$0.00874	\$0.00889	\$0.00874	\$0.00825	\$0.00623	\$0.00822
241	TGP - Fuel Charge % - Z 1-6	In 222 x In 239	\$0.01530	\$0.01574	\$0.01602	\$0.01573	\$0.01486	\$0.01121	\$0.01481
242	<b>Total Volumetric Transportation Rate - TGP (Direct)</b>		<b>\$0.04833</b>	<b>\$0.04902</b>	<b>\$0.04945</b>	<b>\$0.04901</b>	<b>\$0.04765</b>	<b>\$0.04198</b>	<b>\$0.04757</b>
243									
244	<b>TGP (Zone 6 Purchase) Volumetric Transportation Charge</b>								
245	<b>Commodity Costs</b>								Ln 130
246									
247	TGP - Max Comm. Base Rate - Z 6-6	19th Rev Sheet No. 15	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300
248	TGP - Max Commodity ACA Rate - Z 6-6	19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
249	Subtotal TGP - Max Commodity Rate - Z 6-6		\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312
250	TGP - Fuel Charge % - Z 6-6	17th Rev Sheet No. 32	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
251	TGP - Fuel Charge	In 245 x In 250	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
252	<b>Total Vol. Trans. Rate - TGP (Zone 6)</b>		<b>\$0.00312</b>	<b>\$0.00312</b>	<b>\$0.00312</b>	<b>\$0.00312</b>	<b>\$0.00312</b>	<b>\$0.00312</b>	<b>\$0.00312</b>
253									
254									
255	<b>TGP Dracut</b>								
256	<b>Commodity Costs - NYMEX Price</b>								Ln 117
257									
258	TGP - Trans Charge - Comm. - Z 6-6	19th Rev Sheet No. 15	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300
259	TGP - Trans Charge - ACA Rate - Z 6-6	19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
260	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312
261	TGP - Fuel Charge % - Z 6-6	17th Rev Sheet No. 32	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
262	TGP - Fuel Charge	In 256 x In 261							
263	<b>Total Volumetric Transportation Rate - TGP Dracut</b>								
264									
265									

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 Peak 2021 - 2022 Winter Cost of Gas Filing  
 4 NYMEX Futures @ Henry Hub  
 5

Peak

6 For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Strip Average
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8 I. NYMEX Opening Prices as of:								
9 Opening Prices		\$5.5900	\$5.7530	\$5.8540	\$5.7500	\$5.4290	\$4.0980	\$5.4123
10 NYMEX	<b>Filed COG</b>	\$5.5900	\$5.7530	\$5.8540	\$5.7500	\$5.4290	\$4.0980	\$5.4123

Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 d/b/a Liberty

2 Peak 2021 - 2022 Winter Cost of Gas Filing

3 Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Residential Heating Rate R-3

4

5

6 November 1, 2021 - April 30, 2022

7 Residential Heating (R3)

8 PROPOSED

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
9	average Usage (Therms)	62	110	123	148	132	92	667
10								
11	8/1/2021 - Current							
12	Winter:							
13	Cust. Chg \$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 92.34
14	Headblock \$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 375.65
15	Tailblock \$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 0.5632	\$ 375.65
16	HB Threshold -							
17								
24	Total Base Rate Amount	\$ 50.31	\$ 77.34	\$ 84.66	\$ 98.74	\$ 89.73	\$ 67.20	\$ 467.99
25								
26	COG Rate - (Seasonal)	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339
27	COG amount	\$ 70.30	\$ 124.73	\$ 139.47	\$ 167.82	\$ 149.67	\$ 104.32	\$ 756.31
28								
29	LDAC	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444
30	LDAC amount	\$ 8.95	\$ 15.89	\$ 17.76	\$ 21.37	\$ 19.06	\$ 13.29	\$ 96.33
31								
32	<b>Total Bill</b>	<b>\$ 129.56</b>	<b>\$ 217.96</b>	<b>\$ 241.90</b>	<b>\$ 287.94</b>	<b>\$ 258.47</b>	<b>\$ 184.81</b>	<b>\$ 1,320.63</b>

34 November 1, 2020 - April 30, 2021

35 Residential Heating (R3)

36 CURRENT

		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
37	average Usage (Therms)	62	110	123	148	132	92	667
38								
39								
40	Winter:							
41	Cust. Chg \$ 15.50 7/1/20 - 7/31/21 8/1/2021 - Current	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 93.00
42	Headblock \$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 378.72
43	Tailblock \$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 0.5678	\$ 378.72
44	HB Threshold -							
45								
52	Total Base Rate Amount	\$ 50.70	\$ 77.96	\$ 85.34	\$ 99.53	\$ 90.45	\$ 67.74	\$ 471.72
53								
54	COG Rate - (Seasonal)	\$ 0.5571	\$ 0.5571	\$ 0.4664	\$ 0.4276	\$ 0.5156	\$ 0.6050	\$ 0.5100
55	COG amount	\$ 34.54	\$ 61.28	\$ 57.37	\$ 63.28	\$ 68.06	\$ 55.66	\$ 340.19
56								
57	LDAC	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589
58	LDAC amount	\$ 3.65	\$ 6.48	\$ 7.24	\$ 8.72	\$ 7.77	\$ 5.42	\$ 39.29
59								
60	<b>Total Bill</b>	<b>\$ 88.90</b>	<b>\$ 145.72</b>	<b>\$ 149.95</b>	<b>\$ 171.54</b>	<b>\$ 166.28</b>	<b>\$ 128.82</b>	<b>\$ 851.20</b>

61 DIFFERENCE:

62	<b>Total Bill</b>	<b>\$40.67</b>	<b>\$72.24</b>	<b>\$91.95</b>	<b>\$116.40</b>	<b>\$92.19</b>	<b>\$55.99</b>	<b>\$469.43</b>
63	% Change	<b>45.75%</b>	<b>49.57%</b>	<b>61.32%</b>	<b>67.86%</b>	<b>55.44%</b>	<b>43.47%</b>	<b>55.15%</b>
64								
65								
66	<b>Base Rate</b>	<b>\$ (0.40)</b>	<b>\$ (0.62)</b>	<b>\$ (0.68)</b>	<b>\$ (0.79)</b>	<b>\$ (0.72)</b>	<b>\$ (0.53)</b>	<b>\$ (3.73)</b>
67	% Change	<b>-0.78%</b>	<b>-0.79%</b>	<b>-0.79%</b>	<b>-0.79%</b>	<b>-0.79%</b>	<b>-0.79%</b>	<b>-0.79%</b>
68								
69	<b>COG &amp; LDAC</b>	<b>\$ 41.06</b>	<b>\$ 72.86</b>	<b>\$ 92.62</b>	<b>\$ 117.19</b>	<b>\$ 92.90</b>	<b>\$ 56.53</b>	<b>\$ 473.16</b>
70	% Change	<b>118.89%</b>	<b>118.89%</b>	<b>161.45%</b>	<b>185.18%</b>	<b>136.51%</b>	<b>101.56%</b>	<b>139.09%</b>



Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 d/b/a Liberty

2 Peak 2021 - 2022 Winter Cost of Gas Filing

3 Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-41

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6 November 1, 2021 - April 30, 2022

7 Commercial Rate (G-41)

8 PROPOSED

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
9	average Usage (Therms)	89	277	504	457	331	297	1,955
12	Winter:	<u>8/1/2021 - Current</u>						
13	Cust. Chg	\$ 57.06	\$ 57.06	\$ 57.06	\$ 57.06	\$ 57.06	\$ 57.06	\$ 342.36
14	Headblock	\$ 0.4688	\$ 0.4688	\$ 0.4688	\$ 0.4688	\$ 0.4688	\$ 0.4688	\$ 276.12
15	Tailblock	\$ 0.3149	\$ 0.3149	\$ 0.3149	\$ 0.3149	\$ 0.3149	\$ 0.3149	\$ 1,955.00
16	HB Threshold	100	100	100	100	100	100	100
24	Total Base Rate Amount	\$ 98.78	\$ 159.68	\$ 231.16	\$ 216.36	\$ 176.68	\$ 165.98	\$ 1,048.64
26	COG Rate - (Seasonal)	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341
27	COG amount	\$ 100.93	\$ 314.15	\$ 571.59	\$ 518.28	\$ 375.39	\$ 336.83	\$ 2,217.17
29	LDAC	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
30	LDAC amount	\$ 7.81	\$ 24.32	\$ 44.25	\$ 40.13	\$ 29.06	\$ 26.08	\$ 171.66
32	<b>Total Bill</b>	<b>\$207.53</b>	<b>\$498.15</b>	<b>\$847.00</b>	<b>\$774.77</b>	<b>\$581.13</b>	<b>\$528.88</b>	<b>\$3,437.46</b>

34 November 1, 2020 - April 30, 2021

35 Commercial Rate (G-41)

36 CURRENT

		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
38	average Usage (Therms)	89	277	504	457	331	297	1,955
40	Winter:	<u>7/1/20 - 7/31/21</u>		<u>8/1/2021 - Current</u>				
41	Cust. Chg	\$ 57.46	\$ 57.46	\$ 57.46	\$ 57.46	\$ 57.46	\$ 57.46	\$ 344.76
42	Headblock	\$ 0.4711	\$ 0.4711	\$ 0.4711	\$ 0.4711	\$ 0.4711	\$ 0.4711	\$ 277.48
43	Tailblock	\$ 0.3165	\$ 0.3165	\$ 0.3165	\$ 0.3165	\$ 0.3165	\$ 0.3165	\$ 1,955.00
44	HB Threshold	100	100	100	100	100	100	100
52	Total Base Rate Amount	\$ 99.39	\$ 160.59	\$ 232.44	\$ 217.56	\$ 177.68	\$ 166.92	\$ 1,054.58
54	COG Rate - (Seasonal)	\$ 0.5552	\$ 0.5552	\$ 0.4645	\$ 0.4257	\$ 0.5137	\$ 0.6031	\$ 0.5018
55	COG amount	\$ 49.41	\$ 153.79	\$ 234.11	\$ 194.54	\$ 170.03	\$ 179.12	\$ 981.01
57	LDAC	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
58	LDAC amount	\$ 4.94	\$ 15.37	\$ 27.97	\$ 25.36	\$ 18.37	\$ 16.48	\$ 108.50
60	<b>Total Bill</b>	<b>\$153.74</b>	<b>\$329.75</b>	<b>\$494.52</b>	<b>\$437.47</b>	<b>\$366.09</b>	<b>\$362.52</b>	<b>\$2,144.09</b>

62 DIFFERENCE:

63	<b>Total Bill</b>	\$ 53.79	\$ 168.39	\$ 352.48	\$ 337.30	\$ 215.05	\$ 166.36	\$ 1,293.37
64	% Change	34.99%	51.07%	71.28%	77.10%	58.74%	45.89%	60.32%
66	<b>Base Rate</b>	\$ (0.60)	\$ (0.91)	\$ (1.28)	\$ (1.20)	\$ (1.00)	\$ (0.95)	\$ (5.94)
67	% Change	-0.61%	-0.57%	-0.55%	-0.55%	-0.56%	-0.57%	-0.56%
69	<b>COG &amp; LDAC</b>	\$ 54.40	\$ 169.30	\$ 353.76	\$ 338.50	\$ 216.05	\$ 167.30	\$ 1,299.31
70	% Change	110.09%	110.09%	151.11%	174.00%	127.06%	93.40%	132.45%

Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 d/b/a Liberty

2 Peak 2021 - 2022 Winter Cost of Gas Filing

71 Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-42

72

73

74 November 1, 2021 - April 30, 2022

75 C&I High Winter Use Medium G-42

76 PROPOSED

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
78	average Usage (Therms)	830	2,189	3,708	3,406	2,603	2,395	15,131
79		<u>8/1/2021 - Current</u>						
80	Winter:							
81	Cust. Chg	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14
82	Headblock	\$ 0.4261	\$ 0.4261	\$ 0.4261	\$ 0.4261	\$ 0.4261	\$ 0.4261	\$ 2,484.16
83	Tailblock	\$ 0.2839	\$ 0.2839	\$ 0.2839	\$ 0.2839	\$ 0.2839	\$ 0.2839	\$ 2,640.55
84	HB Threshold	1,000	1,000	1,000	1,000	1,000	1,000	
85								
92	Total Base Rate Amount	\$ 524.85	\$ 934.85	\$ 1,366.09	\$ 1,280.35	\$ 1,052.38	\$ 993.33	\$ 6,151.86
93								
94	COG Rate - (Seasonal)	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341
95	COG amount	\$ 941.30	\$ 2,482.54	\$ 4,205.24	\$ 3,862.74	\$ 2,952.06	\$ 2,716.17	\$ 17,160.07
96								
97	LDAC	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
98	LDAC amount	\$ 72.88	\$ 192.21	\$ 325.59	\$ 299.07	\$ 228.56	\$ 210.30	\$ 1,328.61
99								
100	<b>Total Bill</b>	<b>\$ 1,539.04</b>	<b>\$ 3,609.60</b>	<b>\$ 5,896.92</b>	<b>\$ 5,442.17</b>	<b>\$ 4,233.01</b>	<b>\$ 3,919.80</b>	<b>\$ 24,640.53</b>

101

102 November 1, 2020 - April 30, 2021

103 C&I High Winter Use Medium G-42

104 CURRENT

		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
106	average Usage (Therms)	830	2,189	3,708	3,406	2,603	2,395	15,131
107								
108	Winter:							
109	Cust. Chg	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 1,034.34
110	Headblock	\$ 0.4284	\$ 0.4284	\$ 0.4284	\$ 0.4284	\$ 0.4284	\$ 0.4284	\$ 2,497.57
111	Tailblock	\$ 0.2855	\$ 0.2855	\$ 0.2855	\$ 0.2855	\$ 0.2855	\$ 0.2855	\$ 2,655.44
112	HB Threshold	1,000	1,000	1,000	1,000	1,000	1,000	
113								
120	Total Base Rate Amount	\$ 527.96	\$ 940.25	\$ 1,373.92	\$ 1,287.70	\$ 1,058.45	\$ 999.06	\$ 6,187.35
121								
122	COG Rate - (Seasonal)	\$ 0.5552	\$ 0.5552	\$ 0.4645	\$ 0.4257	\$ 0.5137	\$ 0.6031	\$0.5043
123	COG amount	\$ 460.82	\$ 1,215.33	\$ 1,722.37	\$ 1,449.93	\$ 1,337.16	\$ 1,444.42	\$ 7,630.03
124								
125	LDAC	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
126	LDAC amount	\$ 46.07	\$ 121.49	\$ 205.79	\$ 189.03	\$ 144.47	\$ 132.92	\$ 839.77
127								
128	<b>Total Bill</b>	<b>\$ 1,034.84</b>	<b>\$ 2,277.07</b>	<b>\$ 3,302.08</b>	<b>\$ 2,926.67</b>	<b>\$ 2,540.07</b>	<b>\$ 2,576.41</b>	<b>\$ 14,657.15</b>

129

130 DIFFERENCE:

131	Total Bill	\$ 504.19	\$ 1,332.53	\$ 2,594.84	\$ 2,515.50	\$ 1,692.93	\$ 1,343.39	\$ 9,983.38
132	% Change	48.72%	58.52%	78.58%	85.95%	66.65%	52.14%	68.11%
133								
134	Base Rate	\$ (3.11)	\$ (5.40)	\$ (7.83)	\$ (7.35)	\$ (6.06)	\$ (5.73)	\$ (35.49)
135	% Change	-0.59%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%
136								
137	COG & LDAC	\$ 507.30	\$ 1,337.93	\$ 2,602.67	\$ 2,522.85	\$ 1,699.00	\$ 1,349.12	\$ 10,018.87
138	% Change	110.09%	110.09%	151.11%	174.00%	127.06%	93.40%	131.31%

Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 d/b/a Liberty

2 Peak 2021 - 2022 Winter Cost of Gas Filing

139 Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-52

140

141

142 November 1, 2021 - April 30, 2022

143 Commercial Rate (G-52)

144 PROPOSED

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
145	average Usage (Therms)	1,352	1,866	2,284	2,160	1,886	1,760	11,308
147	Winter:	<u>8/1/2021 - Current</u>						
149	Cust. Chg	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14
150	Headblock	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 1,456.80
151	Tailblock	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 858.30
152	HB Threshold	1,000	1,000	1,000	1,000	1,000	1,000	
160	Total Base Rate Amount	\$ 470.91	\$ 554.02	\$ 621.61	\$ 601.56	\$ 557.26	\$ 536.88	\$ 3,342.24
162	COG Rate - (Seasonal)	\$1.1324	\$1.1324	\$1.1324	\$1.1324	\$1.1324	\$1.1324	\$ 1,1324
163	COG amount	\$ 1,531.00	\$ 2,113.06	\$ 2,586.40	\$ 2,445.98	\$ 2,135.71	\$ 1,993.02	\$ 12,805.18
165	LDAC	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
166	LDAC amount	\$ 118.72	\$ 163.85	\$ 200.55	\$ 189.66	\$ 165.60	\$ 154.54	\$ 992.92
168	<b>Total Bill</b>	<b>\$2,120.63</b>	<b>\$2,830.93</b>	<b>\$3,408.57</b>	<b>\$3,237.21</b>	<b>\$2,858.57</b>	<b>\$2,684.45</b>	<b>\$17,140.34</b>

170 November 1, 2020 - April 30, 2021

171 Commercial Rate (G-52)

172 CURRENT

		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
173	average Usage (Therms)	1,352	1,866	2,284	2,160	1,886	1,760	11,308
176	Winter:	<u>7/1/20 - 7/31/21</u>		<u>8/1/2021 - Current</u>				
177	Cust. Chg	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 1,034.34
178	Headblock	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 1,463.40
179	Tailblock	\$ 0.1624	\$ 0.1624	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 862.02
180	HB Threshold	1,000	1,000	1,000	1,000	1,000	1,000	
188	Total Base Rate Amount	\$ 473.45	\$ 556.93	\$ 624.81	\$ 604.67	\$ 560.18	\$ 539.71	\$ 3,359.76
190	COG Rate - (Seasonal)	\$ 0.5660	\$ 0.5660	\$ 0.4753	\$ 0.4365	\$ 0.5245	\$ 0.6139	\$ 0.5235
191	COG amount	\$ 765.23	\$ 1,056.16	\$ 1,085.59	\$ 942.84	\$ 989.21	\$ 1,080.46	\$ 5,919.48
193	LDAC	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
194	LDAC amount	\$ 75.04	\$ 103.56	\$ 126.76	\$ 119.88	\$ 104.67	\$ 97.68	\$ 627.59
196	<b>Total Bill</b>	<b>\$1,313.72</b>	<b>\$1,716.65</b>	<b>\$1,837.16</b>	<b>\$1,667.39</b>	<b>\$1,654.06</b>	<b>\$1,717.86</b>	<b>\$9,906.84</b>

198 DIFFERENCE:

199	<b>Total Bill</b>	<b>\$ 806.91</b>	<b>\$ 1,114.28</b>	<b>\$ 1,571.41</b>	<b>\$ 1,569.82</b>	<b>\$ 1,204.51</b>	<b>\$ 966.59</b>	<b>\$ 7,233.51</b>
200	% Change	<b>61.42%</b>	<b>64.91%</b>	<b>85.53%</b>	<b>94.15%</b>	<b>72.82%</b>	<b>56.27%</b>	<b>73.02%</b>
202	<b>Base Rate</b>	<b>\$ (2.55)</b>	<b>\$ (2.91)</b>	<b>\$ (3.20)</b>	<b>\$ (3.11)</b>	<b>\$ (2.92)</b>	<b>\$ (2.83)</b>	<b>\$ (17.52)</b>
203	% Change	<b>-0.54%</b>	<b>-0.52%</b>	<b>-0.51%</b>	<b>-0.51%</b>	<b>-0.52%</b>	<b>-0.52%</b>	<b>-0.52%</b>
205	<b>COG &amp; LDAC</b>	<b>\$ 809.45</b>	<b>\$ 1,117.19</b>	<b>\$ 1,574.61</b>	<b>\$ 1,572.93</b>	<b>\$ 1,207.43</b>	<b>\$ 969.42</b>	<b>\$ 7,251.02</b>
206	% Change	<b>105.78%</b>	<b>105.78%</b>	<b>145.05%</b>	<b>166.83%</b>	<b>122.06%</b>	<b>89.72%</b>	<b>122.49%</b>

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

1 **d/b/a Liberty**

2 **Peak 2021 - 2022 Winter Cost of Gas Filing**

207 **Residential Heating**

	<u>Winter 2020-21</u>	<u>Winter 2021-22</u>
208		
209 Customer Charge	\$ 15.50	\$ 15.39
210 First 100 Therms	\$ 0.5678	\$ 0.5632
211 Excess 100 Therms	\$ 0.5678	\$ 0.5632
212 LDAC	\$ 0.0589	\$ 0.1444
213 COG	\$ 0.5100	\$ 1.1339
214 Total Adjust	\$ 0.5689	\$ 1.2783

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	<u>Winter 2020-21 COG @</u>	<u>Winter 2021-22 @</u>	<b>Total</b>		<b>Base Rate</b>		<b>COG</b>		<b>LDAC</b>	
			<b>\$ Impact</b>	<b>% Impact</b>	<b>\$ Impact</b>	<b>% Impact</b>	<b>\$ Impact</b>	<b>% Impact</b>	<b>\$ Impact</b>	<b>% Impact</b>
	\$0.5689	\$1.2783	\$0.71	125%						
222 Cooking alone	5 \$21.05	\$24.60	\$3.55	16.85%	\$0.00	0%	\$3.12	13%	\$0.43	2.03%
224	10 \$26.71	\$33.81	\$7.09	26.56%	\$0.00	0%	\$6.24	18%	\$0.86	3.20%
226	20 \$38.03	\$52.22	\$14.19	37.30%	\$0.00	0%	\$12.48	24%	\$1.71	4.50%
228 Water Heating alone	30 \$49.35	\$70.64	\$21.28	43.12%	\$0.00	0%	\$18.72	26%	\$2.57	5.20%
230	45 \$66.34	\$98.26	\$31.92	48.12%	\$0.00	0%	\$28.07	29%	\$3.85	5.80%
232	50 \$72.00	\$107.47	\$35.47	49.27%	\$0.00	0%	\$31.19	29%	\$4.28	5.94%
234 Heating Alone	80 \$100.30	\$153.50	\$53.20	53.04%	\$0.00	0%	\$46.79	30%	\$6.41	6.39%
236	125 \$165.96	\$260.31	\$94.35	56.85%	\$0.00	0%	\$82.97	32%	\$11.37	6.85%
238	150 \$185.21	\$291.62	\$106.41	57.45%	\$0.00	0%	\$93.58	32%	\$12.83	6.93%
240	200 \$241.82	\$383.69	\$141.88	58.67%	\$0.00	0%	\$124.77	33%	\$17.10	7.07%

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

Updated Schedule 9

2 d/b/a Liberty

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3 Peak 2021 - 2022 Winter Cost of Gas Filing

4 Variance Analysis of the Components of the Winter 2020-2021 Actual Results vs Proposed Winter 2021-2022 Cost of Gas Rate

	WINTER 2020-2021 ACTUAL RESULTS (6 months actual)			WINTER 2021-2022 (6 months Proposed)		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
11 Therm Sales (COG)	124,069,459			87,443,741		
16 Demand Charges	\$	11,374,016	\$ 0.0917	\$	13,868,897	\$ 0.1586
18 Purchased Gas		26,038,931	0.2099	71,420,117	72,351,034	0.8274
20 Storage/Produced Gas		-	-	22,796,474	8,429,820	0.0964
22 Hedging (Gain)/Loss		-	-		-	-
25 Total Volumes and Cost	91,441,600	\$ 37,412,947	\$ 0.3015	94,216,591	\$ 94,649,750	\$ 1.0824
27 Direct Costs						
28 Prior Period Balance	\$	2,901,813	\$ 0.0234	\$	1,431,639	\$ 0.0164
29 Interest		29,768	0.0002		44,085	0.0005
30 Prior Period Adjustment		-	-		335,667	0.0038
31 Broker Revenues		(1,528,286)	(0.0123)		(3,600)	(0.0000)
32 Refunds from Suppliers		-	-		-	-
33 Fuel Financing		-	-		-	-
34 Transportation CGA Revenues		(56,511)	(0.0005)		(6,938)	(0.0001)
35 280 Day Margin		-	-		-	-
36 Interruptible Sales Margin		-	-		-	-
37 Capacity Release and Off System Sales Margins		(1,676,512)	(0.0135)		(1,676,512)	(0.0192)
38 Hedging Costs		-	-		-	-
39 FPO Admin Costs		-	-		36,800	0.0004
40 Indirect Costs		-	-		-	-
41 Misc Overhead		-	-		-	-
42 Occupant Disallowance/Credits		-	-		-	-
43 Production & Storage		1,990,996	0.0160		3,685,458	0.0421
44 Bad Debt Adjustment %		-	-		652,544	0.0075
45 Cashout, Broker penalty, Canadian Managed,...		-	-		-	-
46 Total Adjusted Cost	\$	39,074,214	\$ 0.3149	\$	99,148,893	\$ 1.1339

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty

Peak 2021 - 2022 Winter Cost of Gas Filing

Capacity Assignment Calculations 2020-2021

Derivation of Class Assignments and Weightings

Updated Schedule 10A  
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Basic assumptions:

- 1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
- 2 Residential 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	659	715	0.4%	103	613
2	RATE R-3-Resi Htg	66,114	72,399	42.2%	3,617	68,783
3	RATE G-41 (T)	28,689	31,499	18.4%	750	30,749
4	RATE G-51 (S)	2,361	2,534	1.5%	641	1,893
5	RATE G-42 (V)	36,728	40,301	23.5%	1,198	39,104
6	RATE G-52	5,125	5,490	3.2%	1,498	3,992
7	RATE G-43	9,793	10,710	6.2%	678	10,031
8	RATE G-53	5,922	6,346	3.7%	1,715	4,631
9	RATE G-54	1,495	1,608	0.9%	378	1,230
10						
11	Total	156,887	171,602	100.0%	10,577	161,025
12						
13	Residential Total	66,773	73,115	<b>42.607%</b>	3,719	69,396
14	LLF Total	75,211	82,510	<b>48.083%</b>	2,626	79,885
15	HLF Total	14,903	15,977	<b>9.310%</b>	4,232	11,745
16	Total	156,887	171,602	100.0%	10,577	161,025
17						
18	C&I Breakdown					
19	LLF Total				2,626	79,885
20	HLF Total				4,232	11,745
21	Total				6,858	91,630
22						
23	C&I Breakdown Percentage					
24	LLF Total				38.291%	87.182%
25	HLF Total				61.709%	12.818%
26	Total				<b>100.0%</b>	<b>100.0%</b>
27						
28	Capacity Cost	MDQ, Dt	\$/Dt-Mo.			
29	Pipeline	\$16,344,325	119,718	\$11.3770		
30	Storage	\$4,121,310	28,115	\$12.2156		
31						
32	Peaking	\$4,119,000				
33	Peaking Additional Costs					
34	Subtotal Peaking Costs	\$4,119,000	23,769	\$14.4412		
35	Total	\$24,584,635	171,602	\$11.9388		
36						
37	Capacity Cost	MDQ, Dt	\$/Dt-Mo.			
38	Pipeline - Baseload	1,443,958	10,577	\$11.3770		
39	Pipeline - Remaining	14,900,367	109,141	\$11.3770		
40	Storage	4,121,310	28,115	\$12.2156		
41	Peaking	4,119,000	23,769	\$14.4412		
42	Total	24,584,635	171,602	\$11.9388		
43						
44						
45	Residential Allocation	Capacity Cost	MDQ, Dt	\$/Dt-Mo.		
46	Pipeline - Base	Line 38 * Line 13 Col C	615,228	4,506	\$11.3770	
47	Pipeline - Remaining	Line 39 * Line 13 Col C	6,348,623	46,502	\$11.3770	
48	Storage	Line 40 * Line 13 Col C	1,755,962	11,979	\$12.2156	
49	Peaking	Line 41 * Line 13 Col C	1,754,952	10,127	\$14.4412	
50	Total	42.607%	10,474,751	73,114	\$11.9388	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty

Peak 2021 - 2022 Winter Cost of Gas Filing

Capacity Assignment Calculations 2020-2021

Derivation of Class Assignments and Weightings

Updated Schedule 10A  
Page 2 of 3

			Capacity Cost	MDQ, Dt	\$/Dt-Mo.	<b>Ratios for COG</b>
51						
52						
53	C&I Allocation					
54	Pipeline - Base	Line 38 - Line 46	828,730	6,070	\$11.3770	
55	Pipeline - Remaining	Line 39 - Line 47	8,551,745	62,640	\$11.3769	
56	Storage	Line 40 - Line 48	2,365,348	16,136	\$12.2157	
57	Peaking	Line 41 - Line 49	2,364,048	13,642	\$14.4410	
58	Total		<b>57.393%</b> 14,109,870	98,488	\$11.9388	<b>1.0000</b>
59						
60						
61	LLF - C&I Allocation					
62	Pipeline - Base	Line 54 * Line 24 Col E	317,329	2,324	\$11.3787	
63	Pipeline - Remaining	Line 55 * Line 24 Col F	7,455,589	54,610	\$11.3770	
64	Storage	Line 56 * Line 24 Col F	2,062,160	14,068	\$12.2154	
65	Peaking	Line 57 * Line 24 Col F	2,061,026	11,893	\$14.4415	
66	Total		<b>48.3884%</b> 11,896,104	82,895	\$11.9590	<b>1.0017</b>
67			38.291%	84%		(Line 66 / Line 58)
68						
69	HLF - C&I Allocation					
70	Pipeline - Base	Line 54 - Line 62	511,401	3,746	\$11.3766	
71	Pipeline - Remaining	Line 55 - Line 63	1,096,156	8,030	\$11.3756	
72	Storage	Line 56 - Line 64	303,188	2,068	\$12.2174	
73	Peaking	Line 57 - Line 65	303,022	1,749	\$14.4379	
74	Total		<b>9.0047%</b> 2,213,767	15,593	\$11.8310	<b>0.9910</b>
75						(Line 74 / Line 58)
76						
77	Unit Cost		Residential	LLF C&I	HLF C&I	
78						
79	Pipeline		\$ 11.3770	\$ 11.3770	\$ 11.3770	
80	Storage		\$ 12.2156	\$ 12.2156	\$ 12.2156	
81	Peaking		\$ -	\$ -	\$ -	
82	Total		\$ 11.9388	\$ 11.9590	\$ 11.8310	
83						
84						
85	Load Makeup		Residential	<b>LLF C&amp;I</b>	<b>HLF C&amp;I</b>	
86						
87	Pipeline		69.77%	<b>68.68%</b>	<b>75.52%</b>	
88	Storage		16.38%	<b>16.97%</b>	<b>13.26%</b>	
89	Peaking		13.85%	<b>14.35%</b>	<b>11.22%</b>	
90	Total		100.00%	<b>100.00%</b>	<b>100.00%</b>	
91						
92						
93	Supply Makeup		Residential	LLF C&I	HLF C&I	Total
94						
95	Pipeline		42.61%	47.56%	9.84%	100.00%
96	Storage		42.61%	50.04%	7.36%	100.00%
97	Peaking		42.61%	50.04%	7.36%	100.00%

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 2 d/b/a Liberty  
 3 2021 - 2022 Winter Cost of Gas Filing  
 4 Correction Factor Calculation

8 Data Source: Schedule 10B	d	e	f	g	h	i	Total Sales
9	Nov	Dec	Jan	Feb	Mar	Apr	
10							
11 G-41	1,993,710	3,256,330	3,928,840	3,309,510	2,686,900	1,577,780	16,753,070
12 G-42	1,614,090	2,539,420	3,002,840	2,538,570	2,173,870	1,204,090	13,072,880
13 G-43	351,200	532,700	648,170	538,750	488,120	288,000	2,846,940
14 High Winter Use	3,959,000	6,328,450	7,579,850	6,386,830	5,348,890	3,069,870	32,672,890
15							
16 G-51	269,320	351,810	388,860	324,250	336,580	212,980	1,883,800
17 G-52	317,340	408,180	446,890	364,850	374,660	242,020	2,153,940
18 G-53	360,520	440,110	480,670	393,940	408,840	343,630	2,427,710
19 G-54	35,050	39,900	17,030	15,360	16,670	13,800	137,810
21 Low Winter Use	982,230	1,240,000	1,333,450	1,098,400	1,136,750	812,430	6,603,260
22							
23 Gross Total	4,941,230	7,568,450	8,913,300	7,485,230	6,485,640	3,882,300	39,276,150
24							
25							
26 Total Sales				39,276,150			
27 Low Winter Use				6,603,260			
28 Winter Ratio for Low Winter Use				0.9910	Schedule 10A p 2, In 74		
29 High Winter Use				32,672,890			
30 Winter Ratio for High Winter Use				1.0017	Schedule 10A p 2, In 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 =				100.0099%			
34							
35							
36 Allocation Calculation for Miscellaneous Overhead							
37							
38 Projected Winter Sales Volume				11/1/21- 4/30/22		91,676,680	Sch.10B, In 23
39 Projected Annual Sales Volume				11/1/21 - 10/31/22		115,042,810	Sch.10B, In 23
40 Percentage of Winter Sales to Annual Sales						79.69%	



1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty

3 Peak 2021 - 2022 Winter Cost of Gas Filing

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Dry Therms

7 Firm Sales

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9 R-1

10 R-3

11 R-4

12 Total Residential.

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14 G-41

15 G-42

16 G-43

17 G-51

18 G-52

19 G-53

20 G-54

21 Total C/I

22

23 Sales Volume

24

25 Transportation Sales

26 G-41

27 G-42

28 G-43

29 G-51

30 G-52

31 G-53

32 G-54

33

34 Total Trans. Sales

35

36 Total All Sales

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Subtotal PK 21-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Subtotal OP 22	Total
9 R-1	68,340	87,950	100,820	86,060	85,740	64,450	493,360	51,360	38,850	33,950	34,160	38,040	51,620	247,980	741,340
10 R-3	6,259,770	9,415,520	10,967,410	9,270,440	7,794,900	4,711,810	48,419,850	2,667,890	1,294,670	1,005,090	1,028,340	1,719,640	4,100,280	11,815,910	60,235,760
11 R-4	454,380	670,430	779,980	661,890	559,780	360,860	3,487,320	203,890	100,540	76,380	75,540	119,390	284,380	860,120	4,347,440
12 Total Residential.	6,782,490	10,173,900	11,848,210	10,018,390	8,440,420	5,137,120	52,400,530	2,923,140	1,434,060	1,115,420	1,138,040	1,877,070	4,436,280	12,924,010	65,324,540
14 G-41	1,993,710	3,256,330	3,928,840	3,309,510	2,686,900	1,577,780	16,753,070	735,770	276,570	203,130	205,140	361,450	944,100	2,726,160	19,479,230
15 G-42	1,614,090	2,539,420	3,002,840	2,538,570	2,173,870	1,204,090	13,072,880	689,280	298,640	221,790	230,200	400,180	866,050	2,706,140	15,779,020
16 G-43	351,200	532,700	648,170	538,750	488,120	288,000	2,846,940	179,740	73,660	58,680	59,440	100,920	204,000	676,440	3,523,380
17 G-51	269,320	351,810	388,860	324,250	336,580	212,980	1,883,800	201,180	178,670	180,600	181,250	187,340	243,850	1,172,890	3,056,690
18 G-52	317,340	408,180	446,890	364,850	374,660	242,020	2,153,940	222,310	202,670	214,620	214,540	214,530	259,620	1,328,290	3,482,230
19 G-53	360,520	440,110	480,670	393,940	408,840	343,630	2,427,710	308,310	268,810	269,370	265,280	270,620	322,980	1,705,370	4,133,080
20 G-54	35,050	39,900	17,030	15,360	16,670	13,800	137,810	15,120	18,750	22,560	24,140	22,080	24,180	126,830	264,640
21 Total C/I	4,941,230	7,568,450	8,913,300	7,485,230	6,485,640	3,882,300	39,276,150	2,351,710	1,317,770	1,170,750	1,179,990	1,557,120	2,864,780	10,442,120	49,718,270
23 Sales Volume	11,723,720	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	91,676,680	5,274,850	2,751,830	2,286,170	2,318,030	3,434,190	7,301,060	23,366,130	115,042,810
26 G-41	574,020	867,030	1,039,180	856,480	763,130	450,870	4,550,710	261,840	140,990	106,460	95,760	156,800	326,870	1,088,720	5,639,430
27 G-42	1,968,530	2,914,590	3,391,170	2,830,750	2,515,270	1,523,590	15,143,900	906,300	496,460	395,030	398,340	659,800	1,261,210	4,117,140	19,261,040
28 G-43	771,060	1,044,290	1,235,960	1,039,110	971,040	538,960	5,600,420	365,460	237,030	213,480	240,670	339,080	530,620	1,926,340	7,526,760
29 G-51	84,590	105,400	113,700	94,860	99,260	81,810	579,620	77,390	64,770	61,300	61,170	63,740	76,000	404,370	983,990
30 G-52	497,790	617,920	679,580	565,210	579,610	430,990	3,371,100	389,470	360,850	367,700	363,660	373,650	442,840	2,298,170	5,669,270
31 G-53	855,560	987,600	1,082,920	916,680	934,740	840,440	5,617,940	724,650	621,190	623,930	659,410	675,470	791,330	4,095,980	9,713,920
32 G-54	1,585,390	1,292,050	1,269,400	1,054,210	1,161,320	1,357,730	7,720,100	1,561,020	1,567,000	1,631,330	1,739,250	1,682,640	1,755,260	9,936,500	17,656,600
34 Total Trans. Sales	6,336,940	7,828,880	8,811,910	7,357,300	7,024,370	5,224,390	42,583,790	4,286,130	3,488,290	3,399,230	3,558,260	3,951,180	5,184,130	23,867,220	66,451,010
36 Total All Sales	18,060,660	25,571,230	29,573,420	24,860,920	21,950,430	14,243,810	134,260,470	9,560,980	6,240,120	5,685,400	5,876,290	7,385,370	12,485,190	47,233,350	181,493,820

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty

3 Peak 2021 - 2022 Winter Cost of Gas Filing

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7 Volumes (Therms)

Normal Year

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9 For the Months of May 21 - October 21

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13 Pipeline Gas:

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Updated Schedule 11A

Page 1 of 1

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	876,821	926,304	927,705	840,605	911,138	750,758	5,233,331
Niagara Supply	691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
TGP Supply (Gulf)	4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346	17,283,547
Dracut Supply 1 - Baseload	-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
Dracut Supply 2 - Swing	1,775,785	5,569,137	771,324	-	969,754	79,714	9,165,713
Dracut Supply 3 - Swing	-	596,455	290,490	-	1,484	-	888,430
Constellation Combo	89,306	231,576	1,424,042	1,188,519	1,411,967	-	4,345,410
LNG Truck	20,666	21,875	51,371	291,824	362,081	-	747,817
Propane Truck	-	-	-	695,072	-	-	695,072
PNGTS	219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
Portland Natural Gas	1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355	6,284,969
TGP Supply (Z4)	1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071	14,753,578
Subtotal Pipeline Volumes	11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749	75,575,334
	11,146,258	17,666,150	15,671,258	12,655,305	10,660,614	8,575,749	76,375,334
Storage Gas:							
TGP Storage	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
Produced Gas:							
LNG Vapor	21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
Propane	-	-	244,014	574,010	-	-	818,023
Subtotal Produced Gas	21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
Less - Gas Refills:							
LNG Truck	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-	(747,817)
Propane	-	-	-	(695,072)	-	-	(695,072)
TGP Storage Refill	(1,750,690)	-	-	-	-	(961,638)	(2,712,328)
Subtotal Refills	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
Total Sendout Volumes	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211	94,216,591

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty

3 Peak 2021 - 2022 Winter Cost of Gas Filing

44 Normal and Design Year Volumes

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46

47 Volumes (Therms)

Design Year

48

49 For the Months of May 21 - October 21

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53 Pipeline Gas:

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov - Apr
54 Dawn Supply	876,821	926,304	927,705	840,605	911,138	774,673	5,257,245
55 Niagara Supply	691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
56 TGP Supply (Gulf)	4,633,572	3,104,022	3,109,472	2,817,427	3,053,203	763,078	17,480,776
57 Dracut Supply 1 - Baseload	-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
58 Dracut Supply 2 - Swing	4,407,724	6,104,703	1,534,339	1,478,827	2,256,328	1,863,127	17,645,050
59 Dracut Supply 3 - Swing	271,608	619,085	866,906	226,637	179,557	43,480	2,207,273
60 Constellation Combo	-	353,776	1,356,806	1,284,025	1,354,094	-	4,348,701
61 LNG Truck	20,666	21,875	63,459	528,315	118,715	-	753,030
62 Propane Truck	-	-	15,109	680,670	-	-	695,779
63 PNGTS	219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
64 Portland Natural Gas	1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	919,607	6,392,220
65 TGP Supply (Z4)	1,820,806	1,924,268	1,927,178	1,746,396	1,892,764	5,620,543	14,931,954
66 Subtotal Pipeline Volumes	14,012,903	17,946,545	16,570,649	14,678,365	11,824,022	10,857,011	85,889,495
67							
68 Storage Gas:							
69 TGP Storage	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
70							0
71 Produced Gas:							
72 LNG Vapor	21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
73 Propane	-	-	244,014	574,010	-	-	818,023
74 Subtotal Produced Gas	21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
75							
76 Less - Gas Refills:							
77 LNG Truck	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-	-747,817
78 Propane	-	-	-	(695,072)	-	-	-695,072
79 TGP Storage Refill	(1,750,690)	-	-	-	-	(961,638)	-2,712,328
80 Subtotal Refills	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
81							
82 Total Sendout Volumes	15,015,933	19,196,663	22,814,130	19,850,092	16,495,460	11,158,474	104,530,752

Updated Schedule 11B

Page 1 of 1

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty

3 Peak 2021 - 2022 Winter Cost of Gas Filing

4 Capacity Utilization

5 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	
6									
7									
8									
9									
10									
11	<b>Pipeline Gas:</b>								
12	Dawn Supply	5,233,331	4,000	7,240,000	72%	5,257,245	4,000	7,240,000	73%
13	Niagara Supply	4,212,753	3,122	5,650,820	75%	4,212,753	3,122	5,650,820	75%
14	TGP Supply (Gulf + Z4)	32,037,125	21,596	39,088,760	82%	32,412,730	21,596	39,088,760	83%
15	Dracut Supply 1 & 2 & 3	20,704,916	90,000	162,900,000	13%	30,503,096	90,000	162,900,000	19%
16	LNG Truck	747,817	-	-	-	753,030	-	-	-
17	Propane Truck	695,072	-	-	-	695,779	-	-	-
18	PNGTS	1,313,941	1,000	1,810,000	73%	1,313,941	1,000	1,810,000	73%
19	Portland Natural Gas	6,284,969	5,000	9,050,000	69%	6,392,220	5,000	9,050,000	71%
20	Constellation Vapor	4,345,410	7,000	6,300,000	69%	4,348,701	7,000	6,300,000	69%
21									
22									
23	Subtotal Pipeline Volumes	75,575,334				85,889,495			
24									
25	<b>Storage Gas:</b>								
26	TGP Storage	19,999,699		25,791,710	78%	19,999,699		25,791,710	78%
27									
28	<b>Produced Gas:</b>								
29	LNG Vapor	1,978,752				1,978,752			
30	Propane	818,023.3				818,023			
31									
32	Subtotal Produced Gas	2,796,775				2,796,775			
33									
34	<b>Less - Gas Refills:</b>								
35	LNG Truck	(747,817)				(747,817)			
36	Propane	(695,072)				(695,072)			
37	TGP Storage Refill	(2,712,328)				(2,712,328)			
38									
39	Subtotal Refills	(4,155,217)				(4,155,217)			
40									
41	Total Sendout Volumes	94,216,591				104,530,752			

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Forecast of Upcoming Winter Period  
Design Day Report  
2020 / 2021 Heating Season  
(Therms)

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

16

Requirements

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19  
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22

Firm Sales	1,283,926
Interruptible Sales	0
Firm Transportation	432,092
Interruptible Transportation	<u>0</u>

23

Total Requirements 1,716,018

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Resources

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Purchased Pipeline Gas	1,197,180
Underground Storage Gas	281,150
Propane Air Production	41,688
LNG Produced Gas	126,000
Third-Party Supply	<u>70,000</u>

34

Total Resources 1,716,018

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

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Preparation of this report was supervised by:

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Deborah Gilbertson  
Sr. Manager, Energy Procurement

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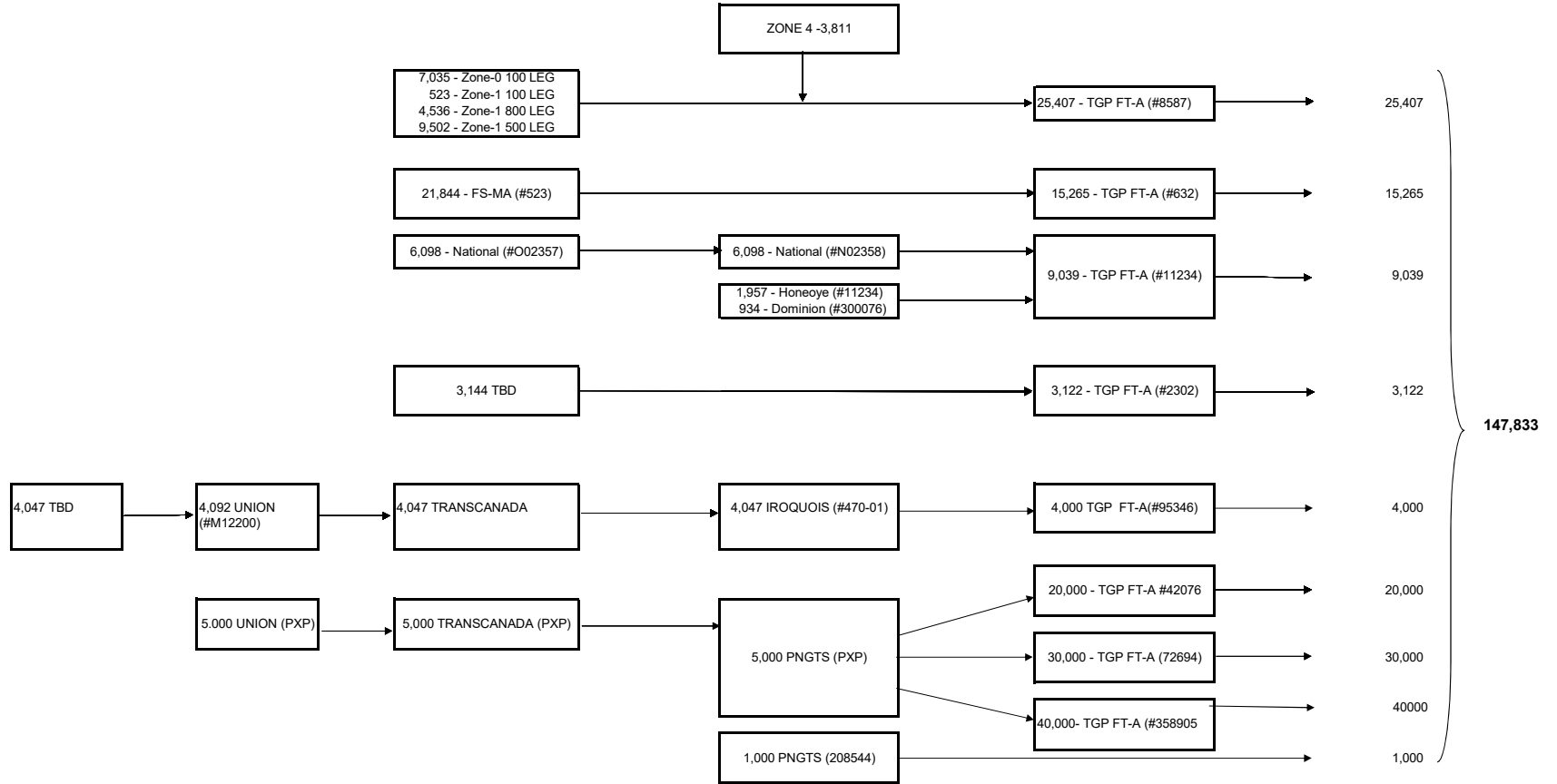
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Note: Forecasted Firm Transportation volumes are for customers  
using utility capacity only.

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.  
 Peak 2021 - 2022 Winter Cost of Gas Filing  
 Transportation Available for Pipeline Supply and Storage

Updated Schedule 12  
 Page 2 of 2

Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
Constellation	FCS		Firm Combination Liquid and Vapor Svc	Up to 10 trucks	730,000	3/31/2021 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2021	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2021	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	3/31/2023	3/31/2021	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2022	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	002358	Storage	6,098	670,800	3/31/2022	3/31/2022	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2022	3/31/2022	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	11/30/2032	11/31/2031	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	5,000	1,825,000	10/31/2040	10/31/2039	Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2028	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2021	11/30/2021	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	358905	Transportation	40,000	14,600,000	10/31/2041	10/31/2040	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2026	10/31/2040	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	5,000	1,825,000	10/31/2040	10/31/2024	Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2023	10/31/2021	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	5,000	1,825,000	10/31/2040	10/31/2021	Precedent Agreement

\* MAQ is calculated on a 365 day calendar year.

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty**  
 2 **Peak 2021 - 2022 Winter Cost of Gas Filing**

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 4 **Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes**  
 5

6 **July 2020 - June 2021 Normalized Sales and Transportation Volumes (Therms)**  
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8				
9		<b>Annual</b>	<b>% of Total</b>	<b>% of Sales</b>
10	<b>C&amp;I Rate Classes</b>	<b>Sales</b>	<b>by Class</b>	<b>to Total Volume</b>
11				<b>by Class</b>
12	G-41	18,356,822	40.75%	78.44%
13	G-42	15,353,253	34.08%	45.73%
14	G-43	3,841,684	8.53%	31.47%
15	G-51	2,891,430	6.42%	76.18%
16	G-52	3,253,957	7.22%	38.33%
17	G-53	1,018,263	2.26%	10.14%
18	G-54	330,714	0.73%	1.92%
19	Total C/I	45,046,124	100.00%	
20				
21				
22		<b>Annual</b>	<b>% of Total</b>	<b>% of Transportation</b>
23		<b>Transportation</b>	<b>by Class</b>	<b>to Total Volume</b>
24				<b>by Class</b>
25	G-41	5,045,712	7.92%	21.56%
26	G-42	18,223,357	28.60%	54.27%
27	G-43	8,366,118	13.13%	68.53%
28	G-51	903,966	1.42%	23.82%
29	G-52	5,236,072	8.22%	61.67%
30	G-53	9,026,718	14.17%	89.86%
31	G-54	16,915,516	26.55%	98.08%
32	Total C/I	63,717,458	100.00%	
33				
34			<b>% of Total</b>	
35	<b>Sales &amp; Transportation</b>	<b>Total</b>	<b>by Class</b>	
36	G-41	23,402,533	21.52%	100.00%
37	G-42	33,576,610	30.87%	100.00%
38	G-43	12,207,803	11.22%	100.00%
39	G-51	3,795,396	3.49%	100.00%
40	G-52	8,490,028	7.81%	100.00%
41	G-53	10,044,981	9.24%	100.00%
42	G-54	17,246,230	15.86%	100.00%
43				
44	Total C/I	108,763,581	100.00%	



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

Updated Schedule 14

2 **Peak 2021 - 2022 Winter Cost of Gas Filing**

Page 1 of 1

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

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	<b>Off-Peak</b>	<b>Peak</b>	<b>Total</b>
	<b>May 20 - Oct 20</b>	<b>Nov 20-Apr 21</b>	<b>May 20 - Apr 21</b>
	(Therms)	(Therms)	(Therms)
Pipeline Deliveries	18,824,010	84,277,810	103,101,820
All Others	132,500	1,914,540	2,047,040
	<u>18,956,510</u>	<u>86,192,350</u>	<u>105,148,860</u>

<b>Ratio</b>
86,192,350
103,101,820
0.836

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4 July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

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**C&I Sales**

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**Normalized (Therms)**

**Jul-20**

**Aug-20**

**Jul - Aug Total**

**Total Annual**

**% of Jul-Aug to Total**

9

(a)

(b)

(c)

(e)=(c)+(d)

(f)

(g)=(e)/(f)

10	G-41	174,747	138,891	313,637	18,356,822	1.71%
11	G-42	195,842	150,099	345,941	15,353,253	2.25%
12	G-43	52,926	47,293	100,219	3,841,684	2.61%
13	G-51	155,287	140,064	295,352	2,891,430	10.21%
14	G-52	183,712	169,419	353,131	3,253,957	10.85%
15	G-53	84,472	58,190	142,662	1,018,263	14.01%
16	G-54	15,457	18,585	34,042	330,714	10.29%
17						
18						
19	Total C/I	862,442	722,541	1,584,983	45,046,124	3.52%
20						
21						

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

5  
 6 Underground Storage Gas

	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Actual)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Nov-21 (Estimate)	Dec-21 (Estimate)	Jan-22 (Estimate)	Feb-22 (Estimate)	Mar-22 (Estimate)	Apr-22 (Estimate)	Total
7 Beginning Balance (MMBtu)	512,647	743,431	993,080	1,249,640	1,509,640	1,769,640	1,897,860	1,750,782	1,665,770	1,115,418	626,366	150,319	512,647
8 Injections (MMBtu) Sch 11A In 39 /10	234,130	253,870	260,938	260,000	260,000	128,220	128,220	-	-	-	-	96,164	1,621,542
9 Subtotal	746,777	997,301	1,254,018	1,509,640	1,769,640	1,897,860	2,026,080	1,750,782	1,665,770	1,115,418	626,366	246,482	
10 Storage Sale/Adjustments	(3,346)	(4,221)	(4,378)	-	-	-	-	-	-	-	-	-	(11,945)
11 Withdrawals (MMBtu) Sch 11A In 29 /10	-	-	-	-	-	-	(275,298)	(85,012)	(550,352)	(489,051)	(476,047)	(124,208)	(1,999,970)
12 Ending Balance (MMBtu)	743,431	993,080	1,249,640	1,509,640	1,769,640	1,897,860	1,750,782	1,665,770	1,115,418	626,366	150,319	122,274	122,274
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Liquid Propane Gas (LPG)		May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Actual)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Nov-21 (Estimate)	Dec-21 (Estimate)	Jan-22 (Estimate)	Feb-22 (Estimate)	Mar-22 (Estimate)	Apr-22 (Estimate)	Total
Beginning Balance		74,752	73,639	73,831	73,396	73,396	73,396	73,396	73,396	73,396	48,995	61,101	61,101	74,752
Injections	Sch 11A In 38 /10	-	-	-	-	-	-	-	-	-	69,507	-	-	69,507
Subtotal		74,752	73,639	73,831	73,396	73,396	73,396	73,396	73,396	73,396	118,502	61,101	61,101	
Withdrawals	Sch 11A In 33 /10	-	-	-	-	-	-	-	-	(24,401)	(57,401)	-	-	(81,802)
Adjustment for change in temperature		(1,113)	192	(435)	-	-	-	-	-	-	-	-	-	(1,356)
Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
Ending Balance		73,639	73,831	73,396	73,396	73,396	73,396	73,396	73,396	48,995	61,101	61,101	61,101	61,101
Beginning Balance		\$ 802,029	\$ 790,087	\$ 792,147	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 525,673	\$ 701,107	\$ 701,107	\$ 802,029
Injections	In 46 * In 69	-	-	-	-	-	-	-	-	-	834,086	-	-	834,086
Subtotal		\$ 802,029	\$ 790,087	\$ 792,147	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 1,359,759	\$ 701,107	\$ 701,107	
Withdrawals/ Adjust	In 52 * In 67	(11,942)	2,060	(4,667)	-	-	-	-	-	(261,807)	(658,652)	-	-	(935,008)
Ending Balance		\$ 790,087	\$ 792,147	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 525,673	\$ 701,107	\$ 701,107	\$ 701,107	\$ 701,107
Average Rate For Withdrawals		\$10.7292	\$10.7292	\$10.7292	\$10.7292	\$10.7292	\$10.7292	\$10.7292	\$10.7292	\$10.7292	\$11.4746	\$11.4746	\$11.4746	
Propane Rate for Injections	Actual or Sch. 6, In 165 * 10	\$10.7292	\$10.7292	\$10.7292	\$0.0000	\$0.0000	\$0.0000	\$12.0000	\$12.0000	\$12.0000	\$12.0000	\$12.0000	\$12.0000	\$12.0000
Month Dollar Average	In (57 + In 65) /2				\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 787,480	\$ 656,576	\$ 613,390	\$ 701,107	\$ 701,107	
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	In 72 * In 74				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Liquid Natural Gas (LNG)</b>		May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Actual)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Nov-21 (Estimate)	Dec-21 (Estimate)	Jan-22 (Estimate)	Feb-22 (Estimate)	Mar-22 (Estimate)	Apr-22 (Estimate)	Total
Beginning Balance		9,988	9,326	8,208	7,858	6,740	5,622	4,504	4,430	(35,570)	(85,164)	(125,392)	(116,488)	9,988
Injections	Sch 11A In 37 /10	809	781	1,468	781	781	781	2,067	2,188	5,137	29,182	36,208	-	80,183
Subtotal		10,797	10,107	9,676	8,639	7,521	6,403	6,571	6,618	(30,433)	(55,982)	(89,183)	(116,488)	
Withdrawals	Sch 11A In 32 /10	(1,471)	(1,899)	(1,818)	(1,899)	(1,899)	(1,899)	(2,140)	(42,188)	(54,731)	(69,410)	(27,304)	(2,102)	(208,760)
Ending Balance		9,326	8,208	7,858	6,740	5,622	4,504	4,430	(35,570)	(85,164)	(125,392)	(116,488)	(118,589)	(118,589)
Beginning Balance		\$ 44,513	\$ 45,885	\$ 44,350	\$ 47,345	\$ 42,683	\$ 37,410	\$ 31,495	\$ 30,889	\$ (249,697)	\$ (594,794)	\$ (867,353)	\$ (813,985)	\$ 44,513
Injections	In 83 * In 104	8,611	8,739	13,841	7,364	7,364	7,364	14,318	15,566	37,152	207,560	244,164	-	572,044
Subtotal		\$ 53,124	\$ 54,624	\$ 58,192	\$ 54,709	\$ 50,047	\$ 44,774	\$ 45,813	\$ 46,456	\$ (212,545)	\$ (387,234)	\$ (623,189)	\$ (813,985)	
Withdrawals	In 87 * In 102	(7,239)	(10,274)	(10,847)	(12,026)	(12,636)	(13,279)	(14,924)	(296,153)	(382,250)	(480,118)	(190,796)	(14,685)	(1,445,226)
Ending Balance		\$ 45,885	\$ 44,350	\$ 47,345	\$ 42,683	\$ 37,410	\$ 31,495	\$ 30,889	\$ (249,697)	\$ (594,794)	\$ (867,353)	\$ (813,985)	\$ (828,670)	\$ (828,670)
Average Rate For Withdrawals		\$4.9203	\$5.4046	\$6.0140	\$6.3328	\$6.6543	\$6.9927	\$6.9725	\$7.0199	\$6.9841	\$6.9172	\$6.9877	\$6.9877	
LNG Rate for Injections	Actual or Sch. 6, In 164 * 10	\$10.6445	\$11.1895	\$9.4287	\$9.4287	\$9.4287	\$9.4287	\$6.9285	\$7.1160	\$7.2321	\$7.1125	\$6.7434	\$0.0000	
Month Dollar Average	In (92 + In 100) /2				\$ 45,014	\$ 40,047	\$ 34,453	\$ 31,192	\$ (109,404)	\$ (422,246)	\$ (731,073)	\$ (840,669)	\$ (821,327)	
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	In 107 * In 109				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Fuel Financing	Ins 53 + 76 + 111				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

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

2 **Peak 2021 - 2022 Winter Cost of Gas Filing**

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4 **Forecast of Firm Transportation Volumes and Cost of Gas Revenues**

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**Firm Transportation**

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	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-21	6,336,940	\$ 0.0002	\$ 1,032
Dec-21	7,828,880	0.0002	1,276
Jan-22	8,811,910	0.0002	1,436
Feb-22	7,357,300	0.0002	1,199
Mar-22	7,024,370	0.0002	1,145
Apr-22	<u>5,224,390</u>	0.0002	<u>851</u>
Total	<u><b>42,583,790</b></u>		<u><b>\$ 6,938</b></u>

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

2/ Refer to Proposed Second Revised Page 98 for calculation of rate.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 Local Delivery Adjustment Charge (LDAC) increase due to Rate Case Expense and Recoupment  
 For LDAC effective November 1, 2021 - October 31, 2022

Updated Schedule 19  
 RCE  
 Page 1 of 2

1	<u>Rate Case Exeexpense</u>	
2	Prior Period Balance	(\$11,949)
3	Expenses thru June 30, 2021	<u>\$785,177</u>
4	Balance at June 30, 2021	\$773,228
5	Less: Accrual Balance	<u>(\$26,000)</u>
6	Adjusted Rate Case Expense	\$747,228
7		
8	<u>Recoupment</u>	
9	Distribution Recoupment from Docket No. DG 20-105	(\$568,780)
10	Indirect Costs Recoupment from Docket No. DG 20-105	<u>\$1,900,000</u>
11	Total Recoupment	\$1,331,220
12		
13	Beginning Balance	\$2,078,448
14		
15	Estimated Remaining Expenses	\$97,375
16		
17	Plus Estimated Interest from July 2021 through October 2021	\$19,820
18		
19	Minus Estimated Recoveries from July 2021 through October 2021	<u>(\$7,864)</u>
20		
21	Total Estimated Remaining Recovery As of November 1, 2021	\$2,187,779
22		
23	Estimated November 2021 - October 2022 Interest	<u>\$26,727</u>
24		
25	Total Remaining Recovery	\$2,214,505
26		
27	Estimated November 2021 - October 2022 Sales (therms)	182,829,872
28		
29	RCE & Recoupment rate per therm November 2021 - October 2022	\$0.0121

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
JULY 2021 THROUGH OCTOBER 2022  
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	Total
1 FOR THE MONTH OF:	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22		
2 DAYS IN MONTH	31	31	30	31	30	31	31	28	31	31	30	31	31	30	31	30		
3 Beginning Balance	\$ 747,228	\$ 2,092,979	\$ 2,180,900	\$ 2,184,876	\$ 2,187,779	\$ 1,972,912	\$ 1,665,779	\$ 1,308,911	\$ 1,008,029	\$ 742,408	\$ 570,514	\$ 455,322	\$ 380,344	\$ 311,946	\$ 241,019	\$ 151,743	\$ 10,996,706	
4																		
5 Add: Additional Rate Case Expense	13,875	83,501	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6																		
7 Add: Recoupment	1,331,220	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
8																		
9 Less: Collected Revenue	(1,423)	(1,471)	(1,847)	(3,123)	(220,417)	(312,148)	(360,968)	(303,766)	(268,034)	(173,704)	(116,560)	(76,129)	(69,352)	(71,664)	(89,818)	(151,945)	(2,214,506)	
10																		
11 Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12																		
13 Ending Balance Pre-Interest	\$ 2,090,900	\$ 2,175,009	\$ 2,179,052	\$ 2,181,752	\$ 1,967,362	\$ 1,660,764	\$ 1,304,811	\$ 1,005,145	\$ 739,995	\$ 568,704	\$ 453,953	\$ 379,192	\$ 310,992	\$ 240,282	\$ 151,201	\$ (202)	\$ 8,782,201	
14																		
15 Month's Average Balance	\$ 753,454	\$ 2,133,994	\$ 2,179,976	\$ 2,183,314	\$ 2,077,571	\$ 1,816,838	\$ 1,485,295	\$ 1,157,028	\$ 874,012	\$ 655,556	\$ 512,234	\$ 417,257	\$ 345,668	\$ 276,114	\$ 196,110	\$ 75,770		
16																		
17 Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
18																		
19 Interest Applied	\$ 2,080	\$ 5,890	\$ 5,823	\$ 6,027	\$ 5,550	\$ 5,015	\$ 4,100	\$ 2,885	\$ 2,413	\$ 1,810	\$ 1,368	\$ 1,152	\$ 954	\$ 738	\$ 541	\$ 202	26,727	
20																		
21 Ending Balance	\$ 2,092,979	\$ 2,180,900	\$ 2,184,876	\$ 2,187,779	\$ 1,972,912	\$ 1,665,779	\$ 1,308,911	\$ 1,008,029	\$ 742,408	\$ 570,514	\$ 455,322	\$ 380,344	\$ 311,946	\$ 241,019	\$ 151,743	\$ (0)		

**Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities**  
**Revenue Decoupling Adjustment Factor (RDAF)**  
**For LDAC effective November 1, 2021 - October 31, 2022**

**Updated Schedule 19**  
**RDAF**  
**Page 1 of 4**

Residential

1	Residential Projected September 1, 2021 Reconciliation Balance of Prior Recoveries / (Refunds)	(\$523,704)
2	Residential Revenue Decoupling Deficiency / (Excess) - Current Period	<u>\$1,522,705</u>
3	Total Residential Revenue Decoupling Deficiency / (Excess) - Prior to Adjustments	\$999,001
4	Adjustments to Residential prior year filings for low income customer treatment	
5	2019 Filing (total adjustment is \$1,932,224 collected over two years)	\$966,112
6	2020 Filing (total adjustment is \$2,092,605 collected over two years)	\$1,046,302
7	Removal of Adjustments to Residential prior year filings for low income customer treatment	<u>(\$2,012,414)</u>
8	Total Residential Revenue Decoupling Deficiency / (Excess) - September 1, 2021	\$999,001
9	Estimated Residential November 2021 - October 2022 Sales (therms)	65,649,919
10	Residential Revenue Decoupling rate per therm November 2020 - October 2021	\$0.0152

Commercial

11	Commercial Projected September 1, 2021 Reconciliation Balance of Prior Recoveries / (Refunds)	(\$446,234)
12	Residential Revenue Decoupling Deficiency / (Excess) - Current Period	<u>\$903,659</u>
13	Total Commercial Revenue Decoupling Deficiency / (Excess) - Current Period	\$457,424
14	Estimated Commercial November 2021 - October 2022 Sales (therms)	117,179,952
15	Commercial Revenue Decoupling rate per therm November 2020 - October 2021	\$0.0039



Liberty Utilities (EnergyNorth Natural Gas) Corp.  
November 2020 through August 2021  
Revenue Decoupling - Credits by Sector

<b>RESIDENTIAL</b>	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
<b>FOR THE MONTH OF:</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>	<b>Jul-21</b>	<b>Aug-21</b>
<b>DAYS IN MONTH</b>	<b>30</b>	<b>31</b>	<b>31</b>	<b>28</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>
Over / Under Beginning Balance	\$ (3,682,012)	\$ (3,465,584)	\$ (3,070,769)	\$ (2,529,984)	\$ (1,925,470)	\$ (1,325,885)	\$ (964,491)	\$ (760,172)	\$ (654,619)	\$ (581,484)
Monthly billing activity	\$ 225,962	\$ 403,824	\$ 548,504	\$ 610,062	\$ 604,066	\$ 364,448	\$ 206,696	\$ 107,440	\$ 74,839	\$ 59,303
Ending Balance Pre-Interest	\$ (3,456,051)	\$ (3,061,761)	\$ (2,522,265)	\$ (1,919,923)	\$ (1,321,404)	\$ (961,436)	\$ (757,795)	\$ (652,732)	\$ (579,780)	\$ (522,181)
Month's Average Balance	\$ (3,569,032)	\$ (3,263,672)	\$ (2,796,517)	\$ (2,224,953)	\$ (1,623,437)	\$ (1,143,661)	\$ (861,143)	\$ (706,452)	\$ (617,200)	\$ (551,832)
Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Interest Applied	\$ (9,534)	\$ (9,009)	\$ (7,719)	\$ (5,547)	\$ (4,481)	\$ (3,055)	\$ (2,377)	\$ (1,887)	\$ (1,704)	\$ (1,523)
Ending Balance	\$ (3,465,584)	\$ (3,070,769)	\$ (2,529,984)	\$ (1,925,470)	\$ (1,325,885)	\$ (964,491)	\$ (760,172)	\$ (654,619)	\$ (581,484)	\$ (523,704)

<b>COMMERCIAL &amp; INDUSTRIAL</b>	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
<b>FOR THE MONTH OF:</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>	<b>Jul-21</b>	<b>Aug-21</b>
<b>DAYS IN MONTH</b>	<b>30</b>	<b>31</b>	<b>31</b>	<b>28</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>
Over / Under Beginning Balance	\$ (2,441,102)	\$ (2,273,218)	\$ (2,038,784)	\$ (1,750,239)	\$ (1,422,472)	\$ (1,089,831)	\$ (870,841)	\$ (725,225)	\$ (617,318)	\$ (528,882)
Monthly billing activity	\$ 174,172	\$ 240,378	\$ 293,767	\$ 331,718	\$ 336,103	\$ 221,606	\$ 147,815	\$ 109,698	\$ 90,016	\$ 83,991
Ending Balance Pre-Interest	\$ (2,266,930)	\$ (2,032,841)	\$ (1,745,017)	\$ (1,418,522)	\$ (1,086,369)	\$ (868,225)	\$ (723,025)	\$ (615,527)	\$ (527,302)	\$ (444,890)
Month's Average Balance	\$ (2,354,016)	\$ (2,153,030)	\$ (1,891,900)	\$ (1,584,380)	\$ (1,254,420)	\$ (979,028)	\$ (796,933)	\$ (670,376)	\$ (572,310)	\$ (486,886)
Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Interest Applied	\$ (6,288)	\$ (5,943)	\$ (5,222)	\$ (3,950)	\$ (3,463)	\$ (2,615)	\$ (2,200)	\$ (1,791)	\$ (1,580)	\$ (1,344)
Ending Balance	\$ (2,273,218)	\$ (2,038,784)	\$ (1,750,239)	\$ (1,422,472)	\$ (1,089,831)	\$ (870,841)	\$ (725,225)	\$ (617,318)	\$ (528,882)	\$ (446,234)

Total Ending Balance	\$ (5,738,803)	\$ (5,109,553)	\$ (4,280,223)	\$ (3,347,941)	\$ (2,415,716)	\$ (1,835,332)	\$ (1,485,397)	\$ (1,271,937)	\$ (1,110,366)	\$ (969,938)
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Liberty Utilities (Energy/North Natural Gas) Corp.  
September 2020 through August 2021  
Revenue Decoupling Activity by Sector

<b>RESIDENTIAL</b>		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
<b>1 FOR THE MONTH OF:</b>		<b>Sep-20</b>	<b>Oct-20</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>	<b>Jul-21</b>	<b>Aug-21</b>
<b>2 DAYS IN MONTH</b>		<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>	<b>28</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>
3	Over Under Beginning Balance		\$ 257,090	\$ 810,822	\$ 1,511,842	\$ 1,582,770	\$ 2,215,950	\$ 2,187,009	\$ 2,273,003	\$ 1,546,131	\$ 1,519,036	\$ 1,546,764	\$ 1,364,717
4													
5	Monthly revenue difference Inc/(Dec) revenue	\$ 240,943	\$ 517,074	\$ 585,965	\$ (5,280)	\$ 630,944	\$ (31,172)	\$ 4,026	\$ (790,048)	\$ (59,223)	\$ 21,114	\$ (186,059)	\$ 154,008
6													
7	True up	15,804	35,187	111,956	71,943	(2,999)	(3,251)	75,821	58,082	27,903	2,525		
8													
9	Ending Balance Pre-Interest	\$ 256,747	\$ 809,350	\$ 1,508,744	\$ 1,578,505	\$ 2,210,715	\$ 2,181,527	\$ 2,266,856	\$ 1,541,037	\$ 1,514,811	\$ 1,542,674	\$ 1,360,705	\$ 1,518,726
10													
11	Month's Average Balance	\$ 128,373	\$ 533,220	\$ 1,159,783	\$ 1,545,174	\$ 1,896,742	\$ 2,198,738	\$ 2,226,932	\$ 1,907,020	\$ 1,530,471	\$ 1,530,855	\$ 1,453,734	\$ 1,441,721
12													
13	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
14													
15	Interest Applied	\$ 343	\$ 1,472	\$ 3,098	\$ 4,265	\$ 5,236	\$ 5,482	\$ 6,147	\$ 5,094	\$ 4,225	\$ 4,089	\$ 4,013	\$ 3,980
16													
17	Ending Balance	\$ 257,090	\$ 810,822	\$ 1,511,842	\$ 1,582,770	\$ 2,215,950	\$ 2,187,009	\$ 2,273,003	\$ 1,546,131	\$ 1,519,036	\$ 1,546,764	\$ 1,364,717	\$ 1,522,705

<b>COMMERCIAL &amp; INDUSTRIAL</b>		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
<b>18 FOR THE MONTH OF:</b>		<b>Sep-20</b>	<b>Oct-20</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>	<b>Jul-21</b>	<b>Aug-21</b>
<b>19 DAYS IN MONTH</b>		<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>	<b>28</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>
20	Over Under Beginning Balance		\$ 29,045	\$ (347,758)	\$ (718,458)	\$ (1,539,810)	\$ (908,753)	\$ (595,095)	\$ 382,115	\$ 405,459	\$ 771,334	\$ 960,953	\$ 838,916
21													
22	Monthly revenue difference Inc/(Dec) revenue	\$ 30,086	\$ (399,411)	\$ (532,021)	\$ (762,675)	\$ 638,015	\$ 406,808	\$ 946,452	\$ (57,824)	\$ 362,977	\$ 219,735	\$ (124,518)	\$ 62,341
23													
24	True up	(1,079)	23,047	162,743	(55,564)	(3,584)	(91,277)	31,051	80,118	1,276	(32,427)		
25													
26	Ending Balance Pre-Interest	\$ 29,007	\$ (347,319)	\$ (717,036)	\$ (1,536,698)	\$ (905,379)	\$ (593,222)	\$ 382,409	\$ 404,409	\$ 769,712	\$ 958,642	\$ 836,435	\$ 901,257
27													
28	Month's Average Balance	\$ 14,503	\$ (159,137)	\$ (532,397)	\$ (1,127,578)	\$ (1,222,594)	\$ (750,988)	\$ (106,343)	\$ 393,262	\$ 587,586	\$ 864,988	\$ 898,694	\$ 870,086
29													
30	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
31													
32	Interest Applied	\$ 39	\$ (439)	\$ (1,422)	\$ (3,112)	\$ (3,375)	\$ (1,872)	\$ (294)	\$ 1,050	\$ 1,622	\$ 2,311	\$ 2,481	\$ 2,402
33													
34	Ending Balance	\$ 29,045	\$ (347,758)	\$ (718,458)	\$ (1,539,810)	\$ (908,753)	\$ (595,095)	\$ 382,115	\$ 405,459	\$ 771,334	\$ 960,953	\$ 838,916	\$ 903,659

35	Total Ending Balance	\$ 286,135	\$ 463,064	\$ 793,384	\$ 42,960	\$ 1,307,197	\$ 1,591,914	\$ 2,655,118	\$ 1,951,590	\$ 2,290,370	\$ 2,507,716	\$ 2,203,633	\$ 2,426,364
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**Liberty Utilities (EnergyNorth Natural Gas) Corp.**  
**Revenue Decoupling**  
**Adjustments to Residential prior year filings for low income customer treatment**

**2019-2020 Filing**

<b>Residential</b>	<b>Filing</b>	<b>Adjusted (1)</b>	<b>Difference</b>
1. Allowed Base Revenue	\$ 40,585,321	\$ 42,517,544	\$ 1,932,224
2. less: Actual and Estimated Base Revenue	44,670,474	44,670,474	-
3. Revenue Deficiency / (Excess)	<u>(4,085,152.93)</u>	<u>(2,152,929.54)</u>	<u>\$ 1,932,224</u>
<b>Commercial</b>			
4. Allowed Base Revenue	\$ 31,436,763	\$ 31,436,763	\$ -
5. less: Actual and Estimated Base Revenue	34,368,401	34,368,401	-
6. Revenue Deficiency / (Excess)	<u>(2,931,638.28)</u>	<u>(2,931,638.28)</u>	<u>\$ -</u>
<b>7. TOTAL Revenue Deficiency / (Excess)</b>	<b><u>(7,016,791.21)</u></b>	<b><u>(5,084,567.82)</u></b>	<b><u>\$ 1,932,224</u></b>

**2020-2021 Filing**

<b>Residential</b>	<b>Filing</b>	<b>Adjusted (1)</b>	<b>Difference</b>
8. Allowed Base Revenue	\$ 47,055,148	\$ 49,147,752	\$ 2,092,605
9. less: Actual and Estimated Base Revenue	50,205,891	50,205,891	-
10. Revenue Deficiency / (Excess)	<u>(3,150,743.35)</u>	<u>(1,058,138.97)</u>	<u>\$ 2,092,605</u>
<b>Commercial</b>			
11. Allowed Base Revenue	\$ 36,558,043	\$ 36,558,043	\$ -
12. less: Actual and Estimated Base Revenue	38,373,247	38,373,247	-
13. Revenue Deficiency / (Excess)	<u>(1,815,203.44)</u>	<u>(1,815,203.44)</u>	<u>\$ -</u>
<b>14. TOTAL Revenue Deficiency / (Excess)</b>	<b><u>(4,965,946.79)</u></b>	<b><u>(2,873,342.41)</u></b>	<b><u>\$ 2,092,605</u></b>

(1) The calculations of the adjusted allowed revenue are included in attachment Attachment 2019-2020 RDAF Adjustment and Attachment 2020-2021 RDAF Adjustment

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 Energy Efficiency Programs  
 For Residential Non-Heating and Heating Classes  
 November 1, 2021 - October 31, 2022  
 Energy Efficiency Charge

Updated Schedule 19  
 Energy Efficiency  
 Page 1 of 3

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures		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
						Residential	Low-Income									
May 21	Actual	(765,079)	(\$0.0831)	(305,597)	404,158	211,716	10,302	15,989	(832,670)	(798,875)	3.25%	(3,178)	(835,848)	2,887,019	3,677,744	31
June 21	Actual	(835,848)	(\$0.0831)	(158,833)	404,158	537,081	111,395	15,989	(330,215)	(583,031)	3.25%	(2,775)	(332,990)	1,308,632	1,911,618	30
July 21	Forecast	(332,990)	(\$0.0831)	(93,229)	404,158	0	0	0	(22,061)	(177,525)	3.25%	(490)	(22,551)	1,121,890	0	31
August 21	Forecast	(22,551)	(\$0.0831)	(90,152)	404,158	0	0	0	291,456	134,453	3.25%	371	291,827	1,084,856	0	31
September 21	Forecast	291,827	(\$0.0831)	(133,428)	404,158	0	0	0	562,557	427,192	3.25%	1,141	563,698	1,605,635	0	30
October 21	Forecast	563,698	(\$0.0831)	(235,825)	404,158	0	0	0	732,031	647,865	3.25%	1,788	733,819	2,837,843	0	31
November 21	Forecast	733,819	(\$0.0861)	(594,247)	404,158	0	0	0	543,731	638,775	3.25%	1,706	545,437	6,901,820	0	30
December 21	Forecast	545,437	(\$0.0861)	(865,560)	404,158	0	0	0	84,035	314,736	3.25%	869	84,904	10,052,958	0	31
January 22	Forecast	84,904	(\$0.0861)	(995,446)	412,449	0	0	0	(498,093)	(206,595)	3.25%	(570)	(498,664)	11,561,514	0	31
February 22	Forecast	(498,664)	(\$0.0861)	(777,324)	412,449	0	0	0	(863,539)	(681,101)	3.25%	(1,698)	(865,237)	9,028,156	0	28
March 22	Forecast	(865,237)	(\$0.0861)	(753,706)	412,449	0	0	0	(1,206,494)	(1,035,866)	3.25%	(2,859)	(1,209,354)	8,753,844	0	31
April 22	Forecast	(1,209,354)	(\$0.0861)	(448,422)	412,449	0	0	0	(1,245,327)	(1,227,340)	3.25%	(3,279)	(1,248,606)	5,208,158	0	30
May 22	Forecast	(1,248,606)	(\$0.0861)	(249,823)	412,449	0	0	0	(1,085,980)	(1,167,293)	3.25%	(3,222)	(1,089,202)	2,901,545	0	31
June 22	Forecast	(1,089,202)	(\$0.0861)	(113,450)	412,449	0	0	0	(790,203)	(939,703)	3.25%	(2,510)	(792,713)	1,317,656	0	30
July 22	Forecast	(792,713)	(\$0.0861)	(83,483)	412,449	0	0	0	(463,747)	(628,230)	3.25%	(1,734)	(465,481)	969,602	0	31
August 22	Forecast	(465,481)	(\$0.0861)	(85,759)	412,449	0	0	0	(138,792)	(302,137)	3.25%	(834)	(139,626)	996,041	0	31
September 22	Forecast	(139,626)	(\$0.0861)	(154,591)	412,449	0	0	0	118,232	(10,697)	3.25%	(29)	118,203	1,795,484	0	30
October 22	Forecast	118,203	(\$0.0861)	(383,367)	412,449	0	0	0	147,285	132,744	3.25%	366	147,652	4,452,576	0	31
November 22	Forecast	147,652	(\$0.0861)	(594,247)	412,449	0	0	0	(34,146)	56,753	3.25%	152	(33,995)	6,901,820	0	30
December 22	Forecast	(33,995)	(\$0.0861)	(865,560)	412,449	0	0	0	(487,105)	(260,550)	3.25%	(719)	(487,825)	10,052,958	0	31

Estimated Residential Conservation Charge Effective November 1, 2021 - October 31, 2022	
Beginning Balance	\$ 733,819
Program Budget Nov 2021-Oct 2022	4,932,804
Projected Interest	(13,794)
Projected Budget with Interest	\$ 5,652,830
<b>Total Charges</b>	<b>\$ 5,652,830</b>
Projected Therm Sales	65,649,919
Residential Rate	\$0.0861
<b>Total Charges with Interest</b>	<b>\$ 5,652,830</b>
Projected Therm Sales	65,649,919
<b>Residential Rate</b>	<b>\$0.0861</b>

Residential Non Heating Therm Sales	0%	741,340	741,340	0%
Residential Heating Therm Sales	35%	64,908,579	64,908,579	35%
C&I Therm Sales	64%	117,249,138	117,249,138	64%
<b>Total Therms</b>	100%	182,899,057	182,899,057	100%
		<u>Budget</u>	<u>Budget</u>	
		2021	2022	
Low-Income Program Budget		\$ 1,523,570	\$ 1,627,400	
Other Refund		-	-	
<b>Total Shared Budget</b>		<b>\$ 1,523,570</b>	<b>\$ 1,627,400</b>	
Residential Program Budget		\$ 3,926,326	\$ 4,059,085	
Residential Performance Incentive		\$ 299,744	\$ 312,757	
<b>Total Residential Program Budget</b>		<b>\$ 4,226,070</b>	<b>\$ 4,371,842</b>	
Commercial/Industrial Program Budget		\$ 3,512,260	\$ 3,886,433	
Commercial/Industrial Program Incentive		\$ 193,174	\$ 213,754	
<b>Total Commercial/Industrial Program Budget</b>		<b>\$ 3,705,434</b>	<b>\$ 4,100,187</b>	
<b>Total Program Budget</b>		<b>\$ 9,455,074</b>	<b>\$ 10,099,429</b>	
Shared Expenses Allocation to Residential		\$ 546,871	\$ 577,544	
Shared Expenses Allocation to C&I		976,699	1,043,260	
<b>Total Allocated Shared Expenses</b>		<b>\$ 1,523,570</b>	<b>\$ 1,620,804</b>	
Total Residential (including allocation of Shared Budget)		\$ 4,772,941	\$ 4,949,386	
Total C&I (including allocation of Shared Budget)		4,682,133	5,143,447	
<b>Total Budget</b>		<b>\$ 9,455,074</b>	<b>\$ 10,092,833</b>	
Total Residential (including allocation of Shared Budget)		\$ 4,772,941	\$ 4,949,386	
Total C&I (including allocation of Shared Budget)		4,682,133	5,143,447	
<b>Total Budget</b>		<b>\$ 9,455,074</b>	<b>\$ 10,092,833</b>	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 Energy Efficiency Programs  
 For Commercial/Industrial Classes  
 November 1, 2021 - October 31, 2022  
 Energy Efficiency Charge

Updated Schedule 19  
 Energy Efficiency  
 Page 2 of 3

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures		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
						C&I	Low-Income									
May 21	Actual	(1,366,413)	(\$0.0441)	(316,425)	455,607	170,075	13,657	14,818	(1,484,288)	(1,425,351)	3.25%	(2,945)	(1,487,233)	6,635,508	7,175,611	31
June 21	Actual	(1,487,233)	(\$0.0441)	(234,819)	455,607	224,152	147,663	14,818	(1,335,419)	(1,411,326)	3.25%	(2,572)	(1,337,991)	4,794,620	5,325,135	30
July 21	Forecast	(1,337,991)	(\$0.0441)	(194,811)	455,607	0	0		(1,077,195)	(1,207,593)	3.25%	(3,333)	(1,080,528)	4,417,480	0	31
August 21	Forecast	(1,080,528)	(\$0.0441)	(190,167)	455,607	0	0		(815,088)	(947,808)	3.25%	(2,616)	(817,705)	4,312,181	0	31
September 21	Forecast	(817,705)	(\$0.0441)	(210,967)	455,607	0	0		(573,065)	(695,385)	3.25%	(1,858)	(574,922)	4,783,833	0	30
October 21	Forecast	(574,922)	(\$0.0441)	(279,638)	455,607	0	0		(398,954)	(486,938)	3.25%	(1,344)	(400,298)	6,340,998	0	31
November 21	Forecast	(400,298)	(\$0.0408)	(467,051)	455,607	0	0		(411,742)	(406,020)	3.25%	(1,085)	(412,826)	11,447,324	0	30
December 21	Forecast	(412,826)	(\$0.0408)	(627,711)	455,607	0	0		(584,931)	(498,879)	3.25%	(1,377)	(586,308)	15,385,075	0	31
January 22	Forecast	(586,308)	(\$0.0408)	(711,095)	428,621	0	0		(868,782)	(727,545)	3.25%	(2,008)	(870,791)	17,428,801	0	31
February 22	Forecast	(870,791)	(\$0.0408)	(609,932)	428,621	0	0		(1,052,102)	(961,446)	3.25%	(2,397)	(1,054,499)	14,949,322	0	28
March 22	Forecast	(1,054,499)	(\$0.0408)	(536,719)	428,621	0	0		(1,162,598)	(1,108,549)	3.25%	(3,060)	(1,165,658)	13,154,881	0	31
April 22	Forecast	(1,165,658)	(\$0.0408)	(369,458)	428,621	0	0		(1,106,496)	(1,136,077)	3.25%	(3,035)	(1,109,530)	9,055,353	0	30
May 22	Forecast	(1,109,530)	(\$0.0408)	(272,836)	428,621	0	0		(953,746)	(1,031,638)	3.25%	(2,848)	(956,594)	6,687,163	0	31
June 22	Forecast	(956,594)	(\$0.0408)	(197,195)	428,621	0	0		(725,168)	(840,881)	3.25%	(2,246)	(727,414)	4,833,207	0	30
July 22	Forecast	(727,414)	(\$0.0408)	(185,428)	428,621	0	0		(484,221)	(605,818)	3.25%	(1,672)	(485,894)	4,544,800	0	31
August 22	Forecast	(485,894)	(\$0.0408)	(192,519)	428,621	0	0		(249,792)	(367,843)	3.25%	(1,015)	(250,807)	4,718,593	0	31
September 22	Forecast	(250,807)	(\$0.0408)	(223,802)	428,621	0	0		(45,988)	(148,398)	3.25%	(396)	(46,385)	5,485,342	0	30
October 22	Forecast	(46,385)	(\$0.0408)	(324,175)	428,621	0	0		58,061	5,838	3.25%	16	58,077	7,945,466	0	31
November 22	Forecast	58,077	(\$0.0408)	(467,051)	428,621	0	0		19,646	38,862	3.25%	104	19,750	11,447,324	0	30
December 22	Forecast	19,750	(\$0.0408)	(627,711)	428,621	0	0		(179,340)	(79,795)	3.25%	(220)	(179,560)	15,385,075	0	31

Estimated C&I Conservation Charge November 1, 2021 - October 31, 2022	
Beginning Balance	(400,298)
Program Budget Nov 2021-Oct 2022	5,197,419
Projected Interest	(21,123)
Program Budget with Interest	4,775,998
<b>Total Charges</b>	<b>\$4,775,998</b>
Projected Therm Sales	117,179,952
C&I Rate	\$0.0408
Total Charges with Interest	<b>\$4,780,942</b>
Projected Therm Sales	117,179,952
<b>C&amp;I Rate</b>	<b>\$0.0408</b>

Liberty Utilities (Energy/North Natural Gas) Corp. d/b/a Liberty  
 Energy Efficiency Programs  
 For Residential and Commercial/Industrial Classes  
 November 1, 2021 - October 31, 2022  
 Energy Efficiency Charge

Updated Schedule 19  
 Energy Efficiency  
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Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures				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
						Residential	C&I	Low-Income	Total									
May 21	Actual	(2,131,493)	n/a	(622,023)	859,765	211,716	170,075	23,959	405,750	30,807	(2,316,958)	(2,224,225)	3.25%	(6,123)	(2,323,081)	12,333,808	12,290,578	31
June 21	Actual	(2,323,081)	n/a	(393,652)	859,765	537,081	224,152	259,058	1,020,292	30,807	(1,665,634)	(1,994,358)	3.25%	(5,346)	(1,670,980)	7,703,669	7,740,734	30
July 21	Forecast	(1,670,980)	n/a	(288,040)	859,765	0	0	0	0	0	(1,099,255)	(1,385,118)	3.25%	(3,823)	(1,103,079)	5,471,615	2,303,736	31
August 21	Forecast	(1,103,079)	n/a	(280,319)	859,765	0	0	0	0	0	(523,633)	(813,356)	3.25%	(2,245)	(525,878)	5,317,216	0	31
September 21	Forecast	(525,878)	n/a	(344,395)	859,765	0	0	0	0	0	(10,508)	(268,193)	3.25%	(716)	(11,225)	6,269,177	0	30
October 21	Forecast	(11,225)	n/a	(515,463)	859,765	0	0	0	0	0	333,077	160,926	3.25%	444	333,522	9,068,225	0	31
November 21	Forecast	333,522	n/a	(1,061,298)	859,765	0	0	0	0	0	131,989	232,755	3.25%	622	132,611	13,857,797	0	30
December 21	Forecast	132,611	n/a	(1,493,271)	859,765	0	0	0	0	0	(500,895)	(184,142)	3.25%	(508)	(501,404)	21,185,695	0	31
January 22	Forecast	(501,404)	n/a	(1,706,541)	841,069	0	0	0	0	0	(1,366,876)	(934,140)	3.25%	(2,578)	(1,369,454)	28,674,991	0	31
February 22	Forecast	(1,369,454)	n/a	(1,387,257)	841,069	0	0	0	0	0	(1,915,641)	(1,642,548)	3.25%	(4,095)	(1,919,737)	30,438,317	0	28
March 22	Forecast	(1,919,737)	n/a	(1,290,425)	841,069	0	0	0	0	0	(2,369,092)	(2,144,414)	3.25%	(5,919)	(2,375,011)	26,349,344	0	31
April 22	Forecast	(2,375,011)	n/a	(817,881)	841,069	0	0	0	0	0	(2,351,823)	(2,363,417)	3.25%	(6,313)	(2,358,136)	19,706,228	0	30
May 22	Forecast	(2,358,136)	n/a	(522,659)	841,069	0	0	0	0	0	(2,039,726)	(2,198,931)	3.25%	(6,070)	(2,045,796)	12,611,378	0	31
June 22	Forecast	(2,045,796)	n/a	(310,645)	841,069	0	0	0	0	0	(1,515,371)	(1,780,583)	3.25%	(4,756)	(1,520,128)	7,850,220	0	30
July 22	Forecast	(1,520,128)	n/a	(268,911)	841,069	0	0	0	0	0	(947,969)	(1,234,048)	3.25%	(3,406)	(951,375)	5,539,370	0	31
August 22	Forecast	(951,375)	n/a	(278,278)	841,069	0	0	0	0	0	(388,583)	(669,979)	3.25%	(1,849)	(390,433)	5,397,037	0	31
September 22	Forecast	(390,433)	n/a	(378,393)	841,069	0	0	0	0	0	72,244	(159,095)	3.25%	(425)	71,819	6,389,467	0	30
October 22	Forecast	71,819	n/a	(707,542)	841,069	0	0	0	0	0	205,346	138,582	3.25%	383	205,729	9,178,841	0	31
November 22	Forecast	205,729	n/a	(1,061,298)	841,069	0	0	0	0	0	(14,500)	95,615	3.25%	255	(14,244)	13,857,797	0	30
December 22	Forecast	(14,244)	n/a	(1,493,271)	841,069	0	0	0	0	0	(666,446)	(340,345)	3.25%	(939)	(667,385)	21,185,695	0	31

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2021 - October 31, 2022	
Beginning Balance	\$ 333,522
Program Budget Nov 2021-Oct 2022	\$ 10,130,223
Projected Interest	\$ (34,917)
Program Budget with Interest	\$ 10,428,828
<b>Total Charges</b>	<b>\$10,428,828</b>

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

Gas Assistance Program

1 <b>Distribution</b>	<b>Customer Charge</b>	<b>Block</b>	<b>Total</b>
2 R-3 Base Rates	\$ 15.39	\$ 0.5632	
3 R-4 Base Rates at 55% of R-3	\$ 8.47	\$ 0.3098	
4 Program Distribution Subsidy	\$ 6.9260	\$ 0.2534	
5 Normal Winter Therms			595
6			
7 Estimated Winter 2021/2022 Distribution Subsidy	\$ 41.56	\$ 150.82	\$ 192.38
8			
9 Number of Estimated 2021/2022 Participants	5,273	47	5,320 (a)
10			
11 <b>COG</b>	<b>ENNG</b>	<b>Keene</b>	<b>Total</b>
12 R-3 COG Rates	\$ 1.1339	\$ 1.2816	
13 R-4 COG Rates at 55% of R-3	\$ 0.6236	\$ 0.7049	
14 Program COG Subsidy	\$ 0.5103	\$ 0.5767	
15			
16 Estimated Winter 2021/2022 COG Subsidy (Ln 5 * Ln 14)	\$ 303.68	\$ 343.21	\$ 646.89
17			
18 Winter Distribution Subsidy times Number of Participants (Ln 7 * Ln 9)			\$ 1,023,450
19 Winter COG Subsidy times Number of Participants (Ln 9 * Ln 16)			\$ 1,617,433
20 Prior Year Ending Balance - Gas Assistance Page 2			\$ 208,239
21 Estimated Annual Administrative Costs			-
22 Total Program Costs			\$ 2,849,123
23			
24 Estimated weather normalized firm therms billed for the			
25 Twelve months ended 10/31/22 sales and transportation			182,829,872
26			
27 <b>Total Gas Assistance Program Charge</b>			<b>\$ 0.0156</b>

(a) Estimated number of participants for 2021/22 is based on the actual number participants as of April 2021.

**Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty**  
**NOVEMBER 2020 THROUGH OCTOBER 2021**  
**RESIDENTIAL GAS ASSISTANCE PROGRAM RECONCILIATION**  
**ACCOUNT 175.6**

	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	Total
<b>1 FOR THE MONTH OF:</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>	<b>Jul-21</b>	<b>Aug-21</b>	<b>Sep-21</b>	<b>Oct-21</b>		
<b>2 DAYS IN MONTH</b>	<b>30</b>	<b>31</b>	<b>31</b>	<b>28</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>30</b>	<b>31</b>	<b>31</b>	<b>30</b>	<b>31</b>		
3 Beginning Balance	\$ 476,374	\$ 426,171	\$ 451,615	\$ 480,838	\$ 502,871	\$ 554,416	\$ 624,872	\$ 664,070	\$ 586,516	\$ 518,743	\$ 448,452	\$ 359,568	\$ 476,374	
4														
5 Add: Actual Costs	85,033.7	251,496.7	331,032.5	350,580.8	361,433.3	277,505.0	168,741.3	8,335.5	-	-	-	-	1,834,159	
6														
7 Less: Collected Revenue	(136,437.3)	(227,260.1)	(303,090.8)	(329,769.2)	(311,340.9)	(208,617.9)	(131,314.9)	(87,553.7)	(69,295.6)	(71,623.9)	(89,962.5)	(152,110.8)	(2,118,378)	
8														
9 Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	
10														
11 Ending Balance Pre-Interest	\$ 424,971	\$ 450,408	\$ 479,556	\$ 501,649	\$ 552,963	\$ 623,304	\$ 662,299	\$ 584,852	\$ 517,220	\$ 447,119	\$ 358,490	\$ 207,457	\$ 192,156	
12														
13 Month's Average Balance	\$ 450,673	\$ 438,290	\$ 465,585	\$ 491,244	\$ 527,917	\$ 588,860	\$ 643,585	\$ 624,461	\$ 551,868	\$ 482,931	\$ 403,471	\$ 283,512		
14														
15 Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
16														
17 Interest Applied	\$ 1,201	\$ 1,207	\$ 1,282	\$ 1,221	\$ 1,453	\$ 1,569	\$ 1,772	\$ 1,664	\$ 1,523	\$ 1,333	\$ 1,078	\$ 783	16,084	
18														
19 Ending Balance	\$ 426,171	\$ 451,615	\$ 480,838	\$ 502,871	\$ 554,416	\$ 624,872	\$ 664,070	\$ 586,516	\$ 518,743	\$ 448,452	\$ 359,568	\$ 208,239	\$ 208,239	



Liberty Utilities (EnergyNorth Natural Gas) Corp d/b/a Liberty  
 Quarterly Report  
 Gas Assistance Program (GAP)  
 2020-21 Discounted 45%

2333

Customer Count	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summary		
	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Actual/ Projected Total To Date (1)	Original Projection (2)	Variance
Actual / Projected No. of Customers													Average		
LIHEAP	3,882	3,905	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,155	4,137	(18)
Non-LIHEAP	680	666	673	673	673	673	673	673	673	673	673	673	673	743	70
Total (a)	4,562	4,571	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,828	4,880	52
<b>GAP Recoveries</b>															
Actual / Projected															
Therm Sales	11,132,422	18,766,131	28,990,315	23,977,478	21,908,725	14,263,510	9,588,709	6,150,863	5,514,402	5,714,634	7,280,826	12,398,042	165,686,055	179,574,679	13,888,624
GAP Rate Per Therm	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121	\$0.0121
Total	\$134,702	\$227,070	\$350,783	\$290,127	\$265,096	\$172,588	\$116,023	\$74,425	\$66,724	\$69,147	\$88,098	\$150,016	\$2,004,801	\$2,172,854	\$168,052
Adjustment	\$1,735	\$190	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,925	\$0	
Total Adjusted Recoveries (3)	\$136,438	\$227,260	\$350,783	\$290,127	\$265,096	\$172,588	\$116,023	\$74,425	\$66,724	\$69,147	\$88,098	\$150,016	\$2,006,727	\$2,172,854	\$166,127
<b>Program Costs</b>															
Actual & Projected Costs															
IT	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Admin. (b)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Education	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Prior Period Ending Balance (c)	476,374	0	0	0	0	0	0	0	0	0	0	0	476,374	476,754	379
Other (incl. Reporting Costs)	789	0	0	0	0	0	0	0	0	0	0	0	789	0	(789)
Fixed Discount	25,724	35,733	34,038	34,038	34,038	34,038	0	0	0	0	0	0	197,609	204,228	6,619
Variable Discount	44,619	116,135	143,737	145,405	136,727	101,372	0	0	0	0	0	0	687,995	749,186	61,191
COG Discount	13,902	99,629	109,389	110,659	104,054	77,148	0	0	0	0	0	0	514,781	737,749	222,968
<b>Avg Monthly Residential Customer</b>	<b>\$ 66.50</b>	<b>\$ 108.64</b>	<b>\$ 146.69</b>	<b>\$ 160.62</b>	<b>\$ 151.71</b>	<b>\$ 124.41</b>	<b>\$ 63.52</b>	<b>\$ 41.86</b>	<b>\$ 30.56</b>	<b>\$ 28.68</b>	<b>\$ 28.68</b>	<b>\$ 35.27</b>	<b>\$987.15</b>	<b>\$1,907.80</b>	<b>\$920.65</b>
<b>v</b>	<b>\$ 48.53</b>	<b>\$ 81.61</b>	<b>\$ 115.53</b>	<b>\$ 130.93</b>	<b>\$ 121.07</b>	<b>\$ 93.93</b>	<b>\$ 63.52</b>	<b>\$ 41.86</b>	<b>\$ 30.56</b>	<b>\$ 28.68</b>	<b>\$ 28.68</b>	<b>\$ 35.27</b>	<b>\$820.18</b>	<b>\$228.58</b>	<b>(\$591.61)</b>
<b>Avg Monthly GAP Customer Disco</b>	<b>\$17.97</b>	<b>\$27.03</b>	<b>\$31.17</b>	<b>\$29.69</b>	<b>\$30.64</b>	<b>\$30.48</b>	<b>\$0.00</b>	<b>\$0.00</b>	<b>\$0.00</b>	<b>\$0.00</b>	<b>\$0.00</b>	<b>\$0.00</b>	<b>\$166.97</b>	<b>\$1,679.22</b>	<b>\$1,512.25</b>
<b>v</b>	<b>27.02%</b>	<b>24.88%</b>	<b>21.25%</b>	<b>18.49%</b>	<b>20.19%</b>	<b>24.50%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>16.91%</b>	<b>88.02%</b>	
<b>Gross Monthly Revenues</b>	<b>\$10,019,053</b>	<b>\$18,375,801</b>	<b>\$28,990,263</b>	<b>\$20,353,998</b>	<b>\$18,671,873</b>	<b>\$11,875,246</b>	<b>\$7,698,494</b>	<b>\$5,238,262</b>	<b>\$4,997,762</b>	<b>\$6,467,910</b>	<b>\$5,113,368</b>	<b>\$8,930,712</b>	<b>\$146,732,741</b>	<b>\$161,677,049</b>	<b>\$14,944,308</b>
<b>ot</b>	<b>5.60%</b>	<b>1.37%</b>	<b>0.99%</b>	<b>1.43%</b>	<b>1.47%</b>	<b>1.79%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>1.28%</b>	<b>1.34%</b>	

(1) This column represents actual data for the months in which such data is available plus projected data for the remaining months in the 12-month program year.  
 (2) GAP Projection on Bates 127 of the 2020-21 Cost of Gas Filing, DG 20-141  
 (3) Ties to the Company's GAP deferral accounts 8840-2-0000-10-1169-1756 & 8843-2-0000-10-1169-1756  
 (a) The actual number of customers provided for this report are the number of registered customers that were billed during the month.  
 (b) Actual administrative costs consists of bill inserts and advertising.  
 (c) The Prior Year 2019-20 under/(over) ending balance.

**Environmental Surcharge - Manufactured Gas Plants**

**Manufactured Gas Plants**

Required Annual Environmental Increase	\$2,351,805
Second one-third of prior period under recoveries (through June 2019)	\$341,389
July 2020 - June 2021 recovery difference between actual and estimate	<u>\$139,028</u>
Environmental Subtotal	\$2,832,222
Overall Annual Net Increase to Rates	\$2,832,222
Estimated weather normalized firm therms billed for the twelve months ended 10/31/2022 - sales and transportation	182,829,872 therms
Surcharge per therm	<u>\$0.0155</u> per therm
<b><u>Total Environmental Surcharge</u></b>	<u><u>\$0.0155</u></u>

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

**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)<sup>1</sup>, 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.

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<sup>1</sup> In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

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- 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.
- 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.

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

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- the gas lines was proposed and verbal approval was obtained from NHDES on November 19, 2001.
- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.
  - ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.
  - Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.
  - The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.
  - ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.
  - By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.
  - ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application administratively complete. The hearing was closed on July 26, 2004 and the permit was issued in September 2004.

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- The capping and re-armoring was 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. NHDES allows ENGI to utilize manual removal of DNAPL as these methods are more effective than the automated recovery system.
- 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 five 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.
- In May 2017, the NHDES requested by letter that all active hazardous waste sites managed by the Hazardous Waste Remediation Bureau include sampling for Per- and Polyfluoroalkyl Substances (PFAS) in one of their groundwater sampling rounds, as part of a statewide study of these compounds. ENGI fulfilled this request during regularly scheduled sampling in 2018.
- 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.
- In a letter dated May 2, 2019, NHDES approved ENGI's 5-year Groundwater Management Permit (GMP) renewal application decreasing the frequency of sampling for all but two wells in the perimeter groundwater management zone. Additionally, NHDES required that a second confirmatory round of PFAS samples be taken in the 2019 GMP monitoring round.
- In the same May 2, 2019 letter, NHDES approved GZA Geoenvironmental's (GZA) proposed cap design transmitted to them on January 30, 2019. The cap design was altered to require an impermeable barrier only under "non-paved" surfaces.
- The cap installation and subsequent paving of the entire property has been pushed out to 2021, due to delays in permitting and the COVID-19 pandemic. **ENGI is still on schedule to complete this project, and has been working toward final design to be used for construction. During the 2020-21 period, ENGI has been working with the City of Nashua to assess the condition of subsurface stormwater and sewer lines, and is preparing applications for NHDES Alteration of Terrain permitting for the property paving.**

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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 complete and approved by NHDES. ENGI is in the process of obtain State and City permitting for this construction, now planned for the 2021 construction season.**
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 NHLPC 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.

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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.

***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)<sup>1</sup> 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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<sup>1</sup> In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

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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 attended these coordination meetings to ensure that the environmental and construction aspects of

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- 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 the sediment remediation were complete in May 2008. A Remedial Action Implementation Report

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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 exceedances 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.
- 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



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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 drafted, 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 in July 2014, with the Annual Summary Report for the 2013/2014 groundwater Monitoring year. 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.
- Per the 2010 Remedial Action Plan and the 2014 Remedial Design Report ENGI removed material from a tar separator, tar well and other subsurface structures, dug four test pits, and installed three new monitoring wells and an extraction well on-site, prior to property paving in Fall 2017. Further removals from subsurface structures were planned for 2018.

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

**MANCHESTER FORMER MGP**

LINE  
NO.

- 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.
- In 2019, ENGI continued to address potential site impacts per the 2014 Remedial Design Report by removing approximately 9,000 gallons of contaminated liquids and sludge from a subsurface tar liquor decanter structure in the gas plant area. After removal, ENGI cleaned the structure and filled it with inert fill. **The details of these activities were reported to NHDES in the 2018/2019 Annual Summary Report dated July 24, 2019.**
- In June 2019, three extraction wells were also installed at the western boundary of the site where an existing well in that area was detecting recoverable product. These wells will be used to remove free product on an ongoing basis. Three additional groundwater monitoring wells were installed in the Holder #3 area to monitor potential impacts detected during previous test pit excavation.
- A pump-down of an existing well on the east side of the property, installed in 2017 to recover oil from a known historical oil tank impact in that area, took place in June 2019. The test succeeded to return recoverable product to the well and it will be used to remove free product on an ongoing basis.
- In addition to routine Groundwater Management Permit (GMP) sampling and reporting, an application for GMP renewal was submitted to NHDES in May 2020 with requests to reduce the frequency of sampling of two wells and adding sampling of the 6 new wells installed in 2017-18. Annual Summary Reports detailing the results of groundwater monitoring at the site continue to be submitted.
- ENGI reconstructed a water supply line near the entrance to the plant generating a substantial amount of soil that required disposal at ESMI, Loudon, NH.
- **ENGI received the renewed GMP on February 26, 2021, effective until 2026, covering the monitoring of 42 groundwater monitoring wells each April and October.**
- **A sinkhole in the LNG Area over Holder #3 was discovered in October 2020. Fill materials were excavated and the sinkhole was repaired. A new sinkhole reappeared in the same area in May 2021, and the process was repeated to**

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

**MANCHESTER FORMER MGP**

LINE  
NO.

**stabilize the area. This area was historically filled with soil and debris when the old holder was decommissioned.**

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.

In 2019, ENGI continued to address potential site impacts per the Remedial Design Report by removing approximately 9,000 gallons of contaminated liquids and sludge from a subsurface structure in the gas plant area, installing three extraction wells at the western boundary of the site, and installing three groundwater monitoring wells in one of the gas holder footprints. Also in 2019, needed reconstruction of a major water supply line near the entrance to the property resulted in the removal of a substantial amount of MGP-impacted soil.

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.

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**MANCHESTER FORMER MGP**

LINE  
NO.

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 legal fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys' fees. *EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds*, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that 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 legal 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 legal fees even if the *pro rata* allocation analysis resulted in the carrier owing 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**

**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)<sup>1</sup>, 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 Winnepesaukee 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

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<sup>1</sup> In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

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**d/b/a LIBERTY**

**LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA**

LINE  
NO.

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.

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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**d/b/a LIBERTY**

**LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA**

**LINE**  
**NO.**

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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**LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA**

**LINE**  
**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 a 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, requiring 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 September 2013 with a Request for



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**d/b/a LIBERTY**

**LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA**

**LINE**  
**NO.**

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 Groundwater Management Permit received on May 10, 2017. In May 2017, the NHDES requested by letter that all active hazardous waste sites managed by the Hazardous Waste Remediation Bureau include sampling for Per- and Polyfluoroalkyl Substances (PFAS) in one of their groundwater sampling rounds, as part of a statewide study of these compounds. ENGI fulfilled this request during regularly scheduled sampling in 2018. **ENGI continues to mow the site twice a year and sample the groundwater per the Groundwater Management Permit each September.**

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

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**d/b/a LIBERTY**

**LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA**

LINE  
NO.

as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

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

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003, the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May 2004, the Supreme Court responded that a “continuous injury-in-fact” trigger should be applied. The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.

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.***

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

**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)<sup>1</sup> 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.

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<sup>1</sup> In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

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**d/b/a LIBERTY**

**CONCORD FORMER MGP**

**LINE**  
**NO.**

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report was submitted to NHDES in September 2009. ENGI met with NHDES to discuss the report findings and strategy for moving forward in October 2009. NHDES issued an approval letter for the Supplemental Site Investigation Report on February 9, 2010. The correspondence approved the report and requested that certain additional activities be completed by ENGI. These requested activities include the following: a) preparation and submission of an Initial Response Action Work Plan to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots and tar wells at the MGP property on Gas Street; b) evaluation of the groundwater conditions in the vicinity of the "Tar Pond" which is depicted on a referenced NHDOT site plan; and c) evaluation of potential indoor air impacts at select locations identified during the additional SSI work.

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. 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

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**CONCORD FORMER MGP**

**LINE**  
**NO.**

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.

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."

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 took place with the developer, and ENGI was negotiating the terms of the property's sale. If the property is transferred, the purchaser's future use design will be taken into account when the final design of the engineered cap is being developed. This site developer has not contacted ENGI since May 2017, and appears to have lost interest in the redevelopment project.

Although a developer had approached the Company during 2016 and into 2017 regarding potential purchase of the property, there has been no movement or activity on a transfer of the holder site. In 2020, further deterioration of the holder structure was observed. In addition, fencing was repaired and added to the areas around the deteriorated areas near the vestibule and the outside scaffolding where the tree fell in 2013.

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**CONCORD FORMER MGP**

**LINE**  
**NO.**

In 2019, the City and the Company jointly prepared a report that details various use options for the Gas Holder site on the east side of the highway, including costs for various scenarios ranging from cleaning and fortifying the holder structure for public entry to demolition of the structure. In response to Liberty's communication that the gas holder needed to be demolished, as the condition of the structure raises significant safety concerns, the Concord City Council established a working group in 2020, comprised of representatives of the City Council, City Staff, Liberty, and the New Hampshire Preservation Alliance ("NHPA"), and charged with developing a plan and assigning responsibilities for stabilization and preservation of the holder house structure. The working group discussions resulted in a plan for the NHPA to raise funds to stabilize the holder house and to manage the relevant construction, and for Liberty to seek Commission approval to contribute up to the estimated costs of demolition and remediation beneath the holder house, as the least cost option for customers.

The City, the NHPA, and Liberty met with Commission Staff in February 2021 and obtained Staff's support for the plan, provided Liberty can demonstrate that the Company's contribution toward the stabilization of the holder house is less than the estimated costs of demolition and remediation that would otherwise have been incurred. In April 2021, the City, the NHPA, and Liberty signed an MOU documenting the above understanding as the parties worked toward a formal agreement. As of the date of this report, the parties are near completion of a formal Emergency Stabilization License Agreement to govern the repairs to the holder house. The NHPA has substantially completed the engineering for the stabilization work and has obtained a contractor to complete the work before the end of 2021. Liberty has substantially completed the estimate to demolish the holder house and remedy any contamination, which estimate will serve as the cap of Liberty's contribution toward stabilization.

On January 21, 2020, NHDES issued a renewed GMP for the site and ENGI continues to monitor wells in the groundwater monitoring system on site every June and October under this permit. ENGI requested that soil vapor monitoring be ceased and NHDES removed this requirement from the new permit. The last GMP Annual Summary Report, submitted to NHDES in February 2021, summarized the results of the 2020 GMP sampling rounds and also described various small source remediation activities undertaken on site in late 2020.

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, 2012

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

**CONCORD FORMER MGP**

**LINE**  
**NO.**

and 2017, 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 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.

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

**CONCORD FORMER MGP**

**LINE**  
**NO.**

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. In May 2017, the NHDES requested by letter that all active hazardous waste sites managed by the Hazardous Waste Remediation Bureau include sampling for Per- and Polyfluoroalkyl Substances (PFAS) in one of their groundwater sampling rounds, as part of a statewide study of these compounds. ENGI fulfilled this request during regularly scheduled sampling in 2018.

During May 19 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. The second round of sediment sampling was conducted in October 2018, the third round of sediment sampling took place in October 2019, **and the fourth in October 2020**. NHDES has accepted the MNR reports submitted by ENGI summarizing the sediment sampling results.

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

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

**CONCORD FORMER MGP**

**LINE**  
**NO.**

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, was provided to NHDES in March 2016.

**Outstanding remedial activities including the investigation for decommissioning of the deep well (historic water supply well), closure of the “old tar separator” and a small drip pot, closure of the on-site storm drain, and removal of an area of soil containing hardened tar were completed in late 2020, and results of these activities were reported to NHDES in the 2020 Annual Summary Report submitted in February 2021 as a requirement of the GMP.**

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 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. ENGI has altered the design of the construction to provide temporary access through the wetland area and a permanent access road that does not encroach on the NHDOT right-of-way.

**In 2020, ENGI obtained the access agreement from the City to the property to allow access for the wetland cap remedy construction. ENGI has commenced the pre-design investigation in 2021. ENGI is designing the wetland cap remedy and is preparing associated NHDES permit applications, with plans to construct the remedy in late summer 2021.**

A renewal application for the Groundwater Management Permit was submitted on August 24, 2017, and the renewed permit was granted by NHDES on November 22, 2017. Groundwater and surface water monitoring continues under this permit every

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

**CONCORD FORMER MGP**

**LINE**  
**NO.**

May and November. The 5-year sediment sampling plan to monitor natural attenuation of MGP residuals in the river began in autumn 2017 and are ongoing each October.

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

REDACTED  
 Schedule 20.2  
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2021 SUMMARY BY SITE

LINE NO.	SITE	REF NO.	1101	1102	1105	1106	1107	100 %	1108	1109	TOTAL
			LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	
1	Concord Pond	DEF056	0.00	316,868.13	0.00	0.00	45,831.64	362,699.77			313,043.04
2	Concord MGP	DEF077	2,734.00	84,993.95	0.00	0.00	340,224.44	427,952.39			383,711.57
3	Laconia/Liberty Hill	DEF086	0.00	12,243.50	0.00	0.00	2,657.60	14,901.10			14,901.10
4	Manchester MGP	DEF057	0.00	32,277.20	0.00	0.00	12,198.45	44,475.65			5,080.33
5	Nashua MGP	DEF054	0.00	95,857.14	0.00	0.00	1,006.70	96,863.84			61,016.23
6	General Expenses	DEF064	0.00	0.00	0.00	0.00	5,645.56	5,645.56			5,645.56
<b>Total Pool Activity</b>			<b>2,734.00</b>	<b>542,239.92</b>	<b>0.00</b>	<b>0.00</b>	<b>407,564.39</b>	<b>952,538.31</b>	<b>0.00</b>	<b>(169,140.48)</b>	<b>783,397.83</b>

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

REDACTED  
 Schedule 20.2  
 Page 2 of 7

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIAION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1											(3,520.34)
2	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13487		2,825.73				2,825.73			2,825.73
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13550		17,644.77				17,644.77			17,644.77
4	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 072920					156.85	156.85			156.85
5	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13578		3,686.41				3,686.41			3,686.41
6											(4,468.48)
7	GZA GEOENVIRONMENTAL INC	0789550		2,385.30				2,385.30			2,385.30
8	GZA GEOENVIRONMENTAL INC	0789549		1,339.50				1,339.50			1,339.50
9	INNOVATIVE ENERGY SYSTEMS, LLC	13658		2,470.09				2,470.09			2,470.09
10	INNOVATIVE ENERGY SYSTEMS, LLC	13686		2,426.35				2,426.35			2,426.35
11	INNOVATIVE ENERGY SYSTEMS, LLC	13631		6,877.47				6,877.47			6,877.47
12											(10,454.92)
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13686		2,426.35				2,426.35			2,426.35
14	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13603		3,371.33				3,371.33			3,371.33
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13631		6,877.47				6,877.47			6,877.47
16	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13658		2,470.09				2,470.09			2,470.09
17	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13728		2,842.81				2,842.81			2,842.81
18											(6,664.45)
19	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13743		6,987.34				6,987.34			6,987.34
20	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13807		2,105.28				2,105.28			2,105.28
21	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13776		2,321.75				2,321.75			2,321.75
22	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13828		21,636.08				21,636.08			21,636.08
23											(10,739.42)
24	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13856		5,163.02				5,163.02			5,163.02
25								0.00			0.00
26	Environmental Staff Time						849.85	849.85			849.85

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

REDACTED  
 Schedule 20.2  
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LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102.00 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	GEI CONSULTANTS, INC.	3074183		9,409.09				9,409.09			9,409.09
2	ANCHOR QEA LLC	69017		8,525.67				8,525.67			8,525.67
3	ANCHOR QEA LLC	69459		9,358.75				9,358.75			9,358.75
4	[REDACTED]										(12,852.50)
5	GEI CONSULTANTS, INC.	3077029		1,348.99				1,348.99			1,348.99
6	ANCHOR QEA LLC	69892		5,424.75				5,424.75			5,424.75
7	GEI CONSULTANTS, INC.	3075631		3,043.98				3,043.98			3,043.98
8	[REDACTED]										(7,174.35)
9	ANCHOR QEA LLC	70380		2,924.64				2,924.64			2,924.64
10	NH DEPT OF ENVIRONMENTAL SERVICES	199212014					1,667.65	1,667.65			1,667.65
11	GEI CONSULTANTS, INC.	3079961		3,474.73				3,474.73			3,474.73
12	ANCHOR QEA LLC	70672		27,832.90				27,832.90			27,832.90
13	NH DEPT OF ENVIRONMENTAL SERVICES	CON PD SQG SELF SERT					270.00	270.00			270.00
14	ANCHOR QEA LLC	71255		21,545.22				21,545.22			21,545.22
15	CLEAN HARBORS	1003544340					726.00	726.00			726.00
16	GEI CONSULTANTS, INC.	3082478		1,717.02				1,717.02			1,717.02
17	GEI CONSULTANTS, INC.	3082662		935.48				935.48			935.48
18	[REDACTED]										(5,110.09)
19	ANCHOR QEA LLC	71773		5,555.03				5,555.03			5,555.03
20	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 012821					215.18	215.18			215.18
21	GEI CONSULTANTS, INC.	3084717		1,765.64				1,765.64			1,765.64
22	AON RISK SERVICES NORTHEAST	6100000228541					39,467.00	39,467.00			39,467.00
23	[REDACTED]										(9,620.64)
24	CASEY MARY	EXP0317-031721					73.50	73.50			73.50
25	ANCHOR QEA LLC	01198		51,170.32				51,170.32			51,170.32
26	AON RISK SERVICES NORTHEAST	6100000228572					1,081.01	1,081.01			1,081.01
27	GEI CONSULTANTS, INC.	3087661		1,299.12				1,299.12			1,299.12
28	GEI CONSULTANTS, INC.	3089541		1,638.59				1,638.59			1,638.59
29	ANCHOR QEA LLC	01955		83,567.66				83,567.66			83,567.66
30	GEI CONSULTANTS, INC.	3086465		1,719.64				1,719.64			1,719.64
31	[REDACTED]										(14,899.15)
32	ANCHOR QEA LLC	02474		70,414.75				70,414.75			70,414.75
33	CLEAN HARBORS	1003747648					933.00	933.00			933.00
34	GEI CONSULTANTS, INC.	3091181		4,196.16				4,196.16			4,196.16
35								-			0.00
36								-			0.00
37	Environmental Staff Time						1,398.30	1,398.30			1,398.30

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

REDACTED  
 Schedule 20.2  
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LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1											(17,964.57)
2	GZA GEOENVIRONMENTAL INC	0802008		28,652.90				28,652.90			28,652.90
3	CLEAN HARBORS	1003471907					65.70	65.70			65.70
4											(4,560.14)
5	ENVIRONMENTAL SOIL MANAGEMENT	1019104					2,193.60	2,193.60			2,193.60
6	CLEAN HARBORS	1003492682					1,895.45	1,895.45			1,895.45
7	ENVIRONMENTAL SOIL MANAGEMENT	1019158					2,010.08	2,010.08			2,010.08
8	CLEAN HARBORS	1003524063					131.40	131.40			131.40
9	CLEAN HARBORS	1003524661					3,496.88	3,496.88			3,496.88
10	CLEAN HARBORS	1003554332					2,011.90	2,011.90			2,011.90
11	GZA GEOENVIRONMENTAL INC	0808710		2,601.30				2,601.30			2,601.30
12	GZA GEOENVIRONMENTAL INC	0810861		1,023.00				1,023.00			1,023.00
13											(15,171.72)
14											(1,359.11)
15											(339.78)
16								0.00			0.00
17	Environmental Staff Time						393.44	393.44			393.44

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

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIAATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1								0.00			0.00
2								0.00			0.00
3	Environmental Staff Time						5,645.56	5,645.56			5,645.56
<b>Total Pool Activity</b>			<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>5,645.56</b>	<b>5,645.56</b>	<b>0.00</b>	<b>0.00</b>	<b>5,645.56</b>

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

REDACTED  
 Schedule 20.2  
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LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CLEAN HARBORS	1003346959					65.70	65.70			65.70
3	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 072920					1,990.42	1,990.42			1,990.42
4	JOE GAUCI LANDSCAPING LLC	2020-7-3576					736.00	736.00			736.00
5	COLLINS TREE SERVICE INC.	41104					10,800.00	10,800.00			10,800.00
6	PARKER FENCE	20-592					6,208.60	6,208.60			6,208.60
7	PARKER FENCE	20-533					29,515.05	29,515.05			29,515.05
8	GZA GEOENVIRONMENTAL INC	0800144		10,500.00				10,500.00			10,500.00
9	CITY OF CONCORD GSD	410184-001 0620					10.21	10.21			10.21
10	CITY OF CONCORD GSD	410184-001 0720					11.01	11.01			11.01
11											(8,027.73)
12	JOE GAUCI LANDSCAPING LLC	2020-6-3576					667.00	667.00			667.00
13	JOE GAUCI LANDSCAPING LLC	2020-8-3576					618.00	618.00			618.00
14	GZA GEOENVIRONMENTAL INC	0801794		816.50				816.50			816.50
15	GZA GEOENVIRONMENTAL INC	0802009		21,005.73				21,005.73			21,005.73
16											(628.61)
17	JOE GAUCI LANDSCAPING LLC	2020-9-3576					184.00	184.00			184.00
18	CITY OF CONCORD GSD	410184-001 083020					10.21	10.21			10.21
19	CITY OF CONCORD GSD	410184-001 093020					10.37	10.37			10.37
20	JOE GAUCI LANDSCAPING LLC	2020-10-3576					1,040.00	1,040.00			1,040.00
21	NH DEPT OF ENVIRONMENTAL SERVICES	198904063					3,550.48	3,550.48			3,550.48
22	CLEAN HARBORS	1003524639					40,795.32	40,795.32			40,795.32
23	NH DEPT OF ENVIRONMENTAL SERVICES	CON-MGP SQG SELF CER					270.00	270.00			270.00
24	CITY OF CONCORD GSD	410184-001 1120					10.36	10.36			10.36
25	CLEAN HARBORS	1003544340					2,072.40	2,072.40			2,072.40
26	CLEAN HARBORS	1003561844					19,411.37	19,411.37			19,411.37
27											(9,168.30)
28	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 012821					161.39	161.39			161.39
29	CLEAN HARBORS	1003604344					34,067.04	34,067.04			34,067.04
30	CITY OF CONCORD GSD	410184-001 0121					10.36	10.36			10.36
31	CITY OF CONCORD GSD	410184-001 1220					10.36	10.36			10.36
32	GZA GEOENVIRONMENTAL INC	0808711		9,493.66				9,493.66			9,493.66
33	GZA GEOENVIRONMENTAL INC	0810412		16,869.24				16,869.24			16,869.24
34	GZA GEOENVIRONMENTAL INC	0810862		26,308.82				26,308.82			26,308.82
35	CITY OF CONCORD GSD	410184-001 022821					10.21	10.21			10.21
36											(10,464.81)
37	CLEAN HARBORS	1003679747					95,186.93	95,186.93			95,186.93
38	CLEAN HARBORS	1003626238					69,422.24	69,422.24			69,422.24
39	CITY OF CONCORD GSD	410184-001 033021					10.21	10.21			10.21
40	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 1479A					215.18	215.18			215.18
41	NH DEPT OF ENVIRONMENTAL SERVICES	051577452FLE					8,412.00	8,412.00			8,412.00
42	CLEAN HARBORS	1003717760					13,177.16	13,177.16			13,177.16
43	CITY OF CONCORD GSD	410184-001 043021					10.68	10.68			10.68
44	ORR & RENO, P.A.	128324	2,734.00					2,734.00			2,734.00
45											(15,951.37)
46	CLEAN HARBORS	1003747648					621.95	621.95			621.95
46	CITY OF CONCORD GSD	410184-001 0521					10.21	10.21			10.21
48								0.00			0.00
49	Environmental Staff Time						922.02	922.02			922.02
50											

THIS PAGE HAS BEEN REDACTED



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 REMEDATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUB-TOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	GEI CONSULTANTS, INC.	3077028		1,385.10				1,385.10			1,385.10
2	GEI CONSULTANTS, INC.	3078905		10,858.40				10,858.40			10,858.40
3	MULLER'S LAWN & LANDSCAPING, LLC	5554					800.00	800.00			800.00
4	GEI CONSULTANTS, INC.	3079960					1,516.84	1,516.84			1,516.84
5	NH DEPT OF ENVIRONMENTAL SERVICES	LHR SQG SELF CERT					270.00	270.00			270.00
6								0.00			0.00
7								0.00			0.00
8								0.00			0.00
9								0.00			0.00
10								0.00			0.00
11	Environmental Staff Time						70.76	70.76			70.76
<b>Total Pool Activity</b>			<b>0.00</b>	<b>12,243.50</b>	<b>0.00</b>	<b>0.00</b>	<b>2,657.60</b>	<b>14,901.10</b>			<b>14,901.10</b>

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

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Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 Environmental Remediation MGPs  
 Tariff page 99

		Concord Pond														DEF056	
		(thru - 9/07) ool #1 - #8	(9/07 - 9/08) ool #9	(9/08 - 9/09) ool #10	(9/09 - 9/10) ool #11	(9/10 - 9/11) ool #12	(9/11 - 9/12) ool #13	(9/12 - 6/13) ool #1	(7/13 - 6/1 ) ool #15	(7/1 - 6/15) ool #16	(7/15 - 6/16) ool #17	(7/16 - 6/17) ool #18	(7/17 - 6/18) ool #19	(7/18 - 6/19) ool #20	(7/19 - 6/20) ool #21	(7/20 - 6/21) ool #22	\$ total
1	1 Remediation costs (i.o. 500051)	5,883,850	95.37	128,187	1 3,000	2 9,160	86, 12	78,387	0,31	89,626	3,20	102,196	138,701	87,282	187,358	362,700	7,715,7 8
2	2 Remediation costs (i.o. 500005)																0
3	A Subtotal - remediation costs	5,883,850	95.37	128,187	1 3,000	2 9,160	86, 12	78,387	0,31	89,626	3,20	102,196	138,701	87,282	187,358	362,700	7,715,7 8
5	5 Cash recover es (i.o. 500061)	-2,075,70	0	-12,608	-6,06	-32, 17	-5,173	-19,318	-7,990	-11,392	-8,61	-1 ,0 7	-11,3 5	-1 ,998	-1 ,59	- 9,657	-2,283,920
6	6 Cash recoveries (i.o. 50000 )	- 5,985															- 5,985
7	7 Recovery costs (i.o. 50000 )	623,78	0	0	0	0	0	0	0	0	0	0	0	0	0	0	623,78
8	8 Transfer Credit from Gas Restructuring																
9	9 B Subtotal - net recoveries	-1,897,905	0	-12,608	-6,06	-32, 17	-5,173	-19,318	-7,990	-11,392	-8,61	-1 ,0 7	-11,3 5	-1 ,998	-1 ,59	- 9,657	-2,106,121
10	10																
11	A+B Total net expenses to recover	3,985,9	95.37	115,579	136,936	216,7 3	81,238	59,069	32,32	78,235	3 ,590	88,1 8	127,356	72,283	172,76	313,0 3	5,609,627
12	12																
13	13																
14	14 Surcharge revenue:																
15	15 Act June 1998 - October 1998	-5 ,889															-5 ,889
16	16 Act November 1998 - October 1999	-538,1 3															-538,1 3
17	17 Act November 1999 - October 2000	-760,871															-760,871
18	18 Act November 2000 - October 2001	-6 ,0 539															-6 ,0 539
19	19 Act November 2001 - October 2002	-625,1 1															-625,1 1
20	20 Act November 2002 - October 2003	-607,87															-607,87
21	21 Act November 2003 - October 200	-305,907															-305,907
22	22 Act November 200 - October 2005	-85,078															-85,078
23	23 Act November 2005- October 2006	-13,750															-13,750
24	24 Act November 2006- October 2007	-1 ,091	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1 ,091
25	25 Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	26 Act November 2012- October 2013	0					-5,002	-5,002									-10,003
27	27 Act November 2013- October 201	0					-12,7 9	-12,7 9									-25, 97
28	28 Act Nov 2009-Oct 2010 Base Rate Rev	0					- , 23	- , 23									- , 23
29	29 Act Nov 2010-Oct 2011 Base Rate Rev	0					-32,310	-32,310									-32,310
30	30 Act Nov 2011-Oct 2012 Base Rate Rev	0					-28, 8	-28, 8									-28, 8
31	31 Act Nov 2012-Oct 2013 Base Rate Rev	0					-2,1 3	-2,1 3									- , 286
32	32 Act Nov 2013-Oct 201 Base Rate Rev	0					0	0									0
33	33 Act Nov 201 -Oct 2015 Base Rate Rev	0					0	0									0
34	34 AES co llections	-69,391	-12,620	-12,90	-13,1 5	-13,221	-13,738	-13,725	-13,9 8	-1 ,173	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	-266,571
35	35 Gas Street overcollection	-23,511															-23,511
36	36 Pr or Period Pool under/overcollect on	332,837	38,5 8	5,088	50,73	155, 09	60,721	116,708	0	0	0	0	0	0	0	0	
37	37																
38	38																
39	C Surcharge Subtotal	-3,739,158	-12,620	-12,90	-13,1 5	-98,295	-33,631	-13,725	-13,9 8	-1 ,173	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	- , 0 1,305
40	40																
41	41																
42	D Net balance to be recovered (A-B C)	2 6,787	82,753	102,675	123,791	118, 8	7,608	5,3 5	18,376	6 ,062	20,185	73, 8	112, 98	57,28	157, 51	297,575	1,568,323
43	43																
44	E Allocat on of Lit gated Recovery		-329,5 0	-102,675	-123,791	- 8,569	0	0	0	0	0	0	0	0	0	0	-60 ,575
45	45																
46	46 Surcharge calculation																
47	47 Unrecovered costs (D E)	0	-2 6,787	0	0	0	0	0	0	9,152	5,767	31, 93	6 ,285	0,917	13 ,958	297,575	337,361
48	48 remaining life	168	72	8	8	8	12	12	12	12	2	36	8	60	72	8	
49	49 one year	8	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	50 F amortization	0	0	0	0	0	0	0	0	9,152	2,88	10, 98	16,071	8,183	22, 93	2,511	111,791
51	51																
52	52 Required annual increase in rates:																
53	53 smaller of D or F	0	0	0	0	0	0	0	0	9,152	2,88	10, 98	16,071	8,183	22, 93	2,511	111,791
54	54																
55	55 forecasted therm sales	1, 56,39 ,990	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	182,890,057	182,899,057
56	56																
57	### surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0001	\$0.0000	\$0.0001	\$0.0001	\$0.0000	\$0.0001	\$0.0002	\$0.0006

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

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

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 Schedule 20.3  
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Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 Environmental Remediation MGPs  
 Tariff page 99

		Laconia & Liberty Hill											DEF086				
		I.o. no. 500005															
		(thru - 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)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	\$ total
		pool #1 - #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	pool #18	pool #19	
		Incl. Audit Corr	Incl. Audit Corr														
1	1 Remediation costs (i.o. 500061)	0															0
2	2 Remediation costs (i.o. 500005)	9,670.88	28,225	607,876	262,678	210,532	269,281	6,2986									2,751,360
3	A Subtotal - remediation costs	9,670.88	28,225	607,876	262,678	210,532	269,281	6,2986									2,751,360
5	5 Cash recover es (i.o. 500061)	0	0	0													0
6	6 Cash recover es (i.o. 50000 )	0	0	0													0
7	7 Recovery costs (i.o. 50000 )	116.3	21,729	0	0	0	0	0									33,372
8	8 Transfer Credit from Gas Restructuring	0	0	0													0
9	9 B Subtotal - net recoveries	116.3	21,729	0	0	0	0	0									33,372
10																	
11	A-B Total net expenses to recover	9,682.131	9,95	607,876	262,678	210,532	269,281	6,2986									2,78,732
12																	
13																	
14	1 Surcharge revenue:																
15	15 Act June 1998 - October 1998	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
16	16 Act November 1998 - October 1999	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
17	17 Act November 1999 - October 2000	-151,933	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-151,933
18	18 Act November 2000 - October 2001	-696,237	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-696,237
19	19 Act November 2001 - October 2002	-796,71	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-796,71
20	20 Act November 2002 - October 2003	-805,3	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-805,3
21	21 Act November 2003 - October 200	-699,215	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-699,215
22	22 Act November 200 - October 2005	-652,26	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-652,26
23	23 Act November 2005- October 2006	-691,159	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-691,159
24	2 Act November 2006- October 2007	-958,171	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-958,171
25	25 Act November 2007- October 2008	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
26	26 Act November 2012- October 2013	0	0	0	0	0	0	0	-20,006								-20,006
27	27 Act November 2013- October 201	0	0	0	0	0	0	0	-25,97	-76,91							-101,988
28	28 Act Nov 2009-Oct 2010 Base Rate Rev	0	0	0	0	0	0	0	-296								-296
29	29 Act Nov 2010-Oct 2011 Base Rate Rev	0	0	0	0	0	0	0	-31,38								-31,38
30	30 Act Nov 2011-Oct 2012 Base Rate Rev	0	0	0	0	0	0	0	-27,632								-27,632
31	31 Act Nov 2012-Oct 2013 Base Rate Rev	0	0	0	0	0	0	0	-1,208								-1,208
32	32 Act Nov 2013-Oct 201 Base Rate Rev	0	0	0	0	0	0	0	-28,33	(28,433)							-85,296
33	33 Act Nov 201 -Oct 2015 Base Rate Rev	0	0	0	0	0	0	0	-21,639	(21,639)							-86,35
34	3 AES collections	0	0	0	0	0	0	0	0								0
35	35 Gas Street overcollection	0	0	0	0	0	0	0	0								0
36	36 Pr or Period Pool under/overcollect on	2,395,362	2,2,38	0	0	0	0	0	-87,311	0							0
37																	
38																	
39	C Surcharge Subtotal	-3,055,765	2,2,38	0	0	-63,313	-197,093	-126,563	(50,071)	(21,639)							-5,822,9
40																	
41																	
42	D Net balance to be recovered (A-B C)	6,626,365	692,393	607,876	262,678	1,7,219	72,188	516,2									18,962,237
43																	
44	E Allocat on of Lit gated Recovery	0	-692,393	-607,876	-262,678	-23,530	0	0									-5,797,76
45																	
46	6 Surcharge calculation																
47	7 Unrecovered costs (D E)	0	0	0	0	0	0	0									2,127,600
48	8 remaining life	1	72	8	8	8	12	12									
49	9 one year	36	12	12	12	12	12	12									
50	F amortization		0	0	0	0	0	0									1,588,357
51																	
52	Required annual increase in rates:																
53	53 smaller of D or F	0	0	0	0	0	0	0									1,588,357
54																	
55	55 forecast them sales	1,10,8,9,639	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	182,899,057	182,899,057
56																	
57	### surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	5,68,8086	1,333,37571	862,886571	2199,96	3989,371,29	2128,726571	\$0.0087

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

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Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 Environmental Remediation MGPs  
 Tariff page 99

		Manchester															DEF057
		(9/00 - 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 - 6/1 )	(7/1 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	(7/17 - 6/18)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	\$ total
		ool #1 - 87	ool #8	ool #9	ool #10	ool #11	ool #12	ool #13	ool #1	ool #15	ool #16	ool #17	ool #18	ool #19	ool #20	ool #21	
1	1 Remediation costs (i.o. 500051)	3,762,097															
2	2 Remediation costs (i.o. 500005)	825,092															
3	A Subtotal - remediation costs	587,189															
5	5 Cash recover es (i.o. 500061)	-765,892															
6	6 Cash recover es (i.o. 50000 )	0															
7	7 Recovery costs (i.o. 50000 )	1,2 ,872															
8	8 Transfer Credit from Gas Restructuring	0															
9	9 B Subtotal - net recoveries	78,979															
10	10 A-B Total net expenses to recover	5,066,169															
11	11 Surcharge revenue:																
12	12 Act June 1998 - October 1998	0															
13	13 Act November 1998 - October 1999	0															
14	14 Act November 1999 - October 2000	0															
15	15 Act November 2000 - October 2001	0															
16	16 Act November 2001 - October 2002	-73,5 3															
17	17 Act November 2002 - October 2003	-75,58															
18	18 Act November 2003 - October 200	-138,576															
19	19 Act November 200 - October 2005	-326,132															
20	20 Act November 2005- October 2006	-563,732															
21	21 Act November 2006- October 2007	-662,265															
22	22 Act November 2007- October 2008	0															
23	23 Act November 2012- October 2013	0															
24	24 Act November 2013- October 201	0															
25	25 Act Nov 2009-Oct 2010 Base Rate Rev	0															
26	26 Act Nov 2010-Oct 2011 Base Rate Rev	0															
27	27 Act Nov 2011-Oct 2012 Base Rate Rev	0															
28	28 Act Nov 2012-Oct 2013 Base Rate Rev	0															
29	29 Act Nov 2013-Oct 201 Base Rate Rev	0															
30	30 Act Nov 201 -Oct 2015 Base Rate Rev	0															
31	31 AES co lections	0															
32	32 Gas Street overcollection	0															
33	33 Pr or Period Pool under/overcollect on	7,525,691															
34	34 C Surcharge Subtotal	5,685, 59															
35	35 D Net balance to be recovered (A-B C)	10,751,628															
36	36 E Allocat on of Lit gated Recovery	0															
37	37 Surcharge calculation	0															
38	38 Unrecovered costs (D E)	0															
39	39 remaining life	168															
40	40 one year	8															
41	41 F amortization	0															
42	42 Required annual increase in rates:																
43	43 smal er of D or F	0															
44	44 forecas ed them sales	1,28 , 2 ,318															
45	45 surcharge per therm	\$0.0000															

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

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

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Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 Environmental Remediation MGPs  
 Tariff page 99

		Nashua													DEF054		
		Corrected per 2/08 Audit															
		(9/00 - 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 - 6/1 )	(7/1 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	(7/17 - 6/18)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	\$ total
		ool #1 - #7	ool #8	ool #9	ool #10	ool #11	ool #12	ool #13	ool #1	ool #15	ool #16	ool #17	ool #18	ool #19	ool #20	ool #21	
1	1 Remediation costs (i.o. 500061)	250,299	107,605	78,535	162,729	65,118	399,00	119,095	63,397	105,917	106,129	100,32	61,78	128,071	39,533	96,86	1,88,513
2	2 Remediation costs (i.o. 500005)	1,771,567															1,771,567
3	A Subtotal - remediation costs	2,021,866	107,605	78,535	162,729	65,118	399,00	119,095	63,397	105,917	106,129	100,32	61,78	128,071	39,533	96,86	3,656,080
5	5 Cash recover es (i.o. 500061)	-22,732	-10,1	-62,26	-63,753	-31,767	-2,990	-199,336	-27,7	-0,699	-3,69	-15,029	-5,955	-6,103	-28,062	-35,88	-676,075
6	6 Cash recover es (i.o. 50000 )	0															0
7	7 Recovery costs (i.o. 50000 )	18,388	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18,388
8	8 Transfer Credit from Gas Restructuring	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	9 B Subtotal - net recoveries	-3	-10,1	-62,26	-63,753	-31,767	-2,990	-199,336	-27,7	-0,699	-3,69	-15,029	-5,955	-6,103	-28,062	-35,88	-657,687
10	10 A-B Total net expenses to recover	2,017,521	97,191	16,289	98,975	33,351	396,11	-80,21	35,950	65,217	62,35	85,31	15,523	81,969	11,72	61,016	2,998,392
12	12																
13	13																
15	15 Act June 1998 - October 1998	0															0
16	16 Act November 1998 - October 1999	0															0
17	17 Act November 1999 - October 2000	0															0
18	18 Act November 2000 - October 2001	0															0
19	19 Act November 2001 - October 2002	-183,857															-183,857
20	20 Act November 2002 - October 2003	-2,3150															-2,3150
21	21 Act November 2003 - October 200	-2,7,639															-2,7,639
22	22 Act November 200 - October 2005	-2,1,05															-2,1,05
23	23 Act November 2005- October 2006	-27,991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-27,991
2	2 Act November 2006- October 2007	-281,815	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-281,815
25	25 Act November 2007- October 2008	0															0
26	26 Act November 2012- October 2013	0					-0,012										-0,012
27	27 Act November 2013- October 201	0					-38,26										-38,26
28	28 Act Nov 2009-Oct 2010 Base Rate Rev	0				0											0
29	29 Act Nov 2010-Oct 2011 Base Rate Rev	0				0											0
30	30 Act Nov 2011-Oct 2012 Base Rate Rev	0				0											0
31	31 Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-20,916										-20,916
32	32 Act Nov 2013-Oct 201 Base Rate Rev	0				0											0
33	33 Act Nov 201 -Oct 2015 Base Rate Rev	0				0											0
3	3 AES co lections	0				0											0
35	35 Gas Street overcollection	0				0											0
36	36 Pr or Period Pool under/overcollect on	3,186,601	733,79	0	0	0	0	5,616	0	0	0	0	0	0	0	0	0
37	37																
38	38																
39	39 C Surcharge Subtotal	1,71,096	733,79	0	0	0		-93,558	0	0	0	0	0	0	0	0	-1,571,680
0	0																
1	1																
2	2 D Net balance to be recovered (A-B C)	3,731,617	830,669	16,289	98,975	33,351	302,853	-80,21	35,950	65,217	62,35	85,31	15,523	81,969	11,72	61,016	1,26,713
3	3																
5	5 E Allocat on of Lit gated Recovery	0	-830,669	-16,289	-98,975	-27,735	0	0	0	0	0	0	0	0	0	0	-973,668
6	6																
7	7 Surcharge calculation																
7	7 Unrecovered costs (D E)	0	0	0	0	0	0	0	9,317	17,838	36,563	8,870	58,59	9,833	61,016	201,987	
8	8 remaining life	36	72	8	8	72	12	12	12	2	36	8	60	72	8		
9	9 one year	36	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	50 F amortization	0	0	0	0	0	0	0	9,317	8,919	12,188	2,218	11,710	1,639	8,717		
51	51																
52	52 Required annual increase in rates:																
53	53 smaler of D or F	0	0	0	0	0	0	0	9,317	8,919	12,188	2,218	11,710	1,639	8,717	5,707	
5	5																
55	55 forecasted therm sales	738,096,27	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	182,899,057	182,899,057
56	56																
###	### surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0001	\$0.0000	\$0.0001	\$0.0000	\$0.0001	\$0.0000	\$0.0000	\$0.0003

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

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

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 Environmental Remediation MGPs  
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		Dover												DEF059
		(9/02 - 9/03)	(9/0 - 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 - 6/1 )	(7/1 - 6/15)	\$ total
		ool #1	ool #2	ool #3	ool #	ool #5	ool #6	ool #7	ool #8	ool #9	ool #10	ool #11	ool #12	
1	1 Remediation costs (i.o. 500061)	0	18.85	2,288	0	0	0	0	0	0	0	0	0	21.1 2
2	2 Remediation costs (i.o. 500005)	181,066												181,066
3	A Subtotal - remediation costs	181,066	18.85	2,288	0	0	0	0	0	0	0	0	0	202,208
5	5 Cash recover es (i.o. 500061)	0												0
6	6 Cash recover es (i.o. 50000 )	0												0
7	7 Recovery costs (i.o. 50000 )	0												0
8	8 Transfer Credit from Gas Restructuring													0
9	B Subtotal - net recoveries	0	0	0	0	0	0	0	0	0	0	0	0	0
10														
11	A-B Total net expenses to recover	181,066	18.85	2,288	0	0	0	0	0	0	0	0	0	202,208
12														
13														
14	1 Surcharge revenue:													
15	15 Act June 1998 - October 1998	0												0
16	16 Act November 1998 - October 1999	0												0
17	17 Act November 1999 - October 2000	0												0
18	18 Act November 2000 - October 2001	0												0
19	19 Act November 2001 - October 2002	0												0
20	20 Act November 2002 - October 2003	0												0
21	21 Act November 2003 - October 200	-29.13												-29.13
22	22 Act November 200 - October 2005	-28.359												-28.359
23	23 Act November 2005- October 2006	-27. 99	0		0	0	0	0	0	0	0	0	0	-27. 99
24	24 Act November 2006- October 2007	-28.181	0	0	0	0	0	0	0	0	0	0	0	-28.181
25	25 Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0
26	26 Act November 2012- October 2013													0
27	27 Act November 2013- October 201													0
28	28 Act Nov 2009-Oct 2010 Base Rate Rev													0
29	29 Act Nov 2010-Oct 2011 Base Rate Rev													0
30	30 Act Nov 2011-Oct 2012 Base Rate Rev													0
31	31 Act Nov 2012-Oct 2013 Base Rate Rev													0
32	32 Act Nov 2013-Oct 201 Base Rate Rev													0
33	33 Act Nov 201 -Oct 2015 Base Rate Rev													0
34	3 AES co lections													0
35	35 Gas Street overcollection													0
36	36 Pr or Period Pool under/overcollect on		67.892	86.7 6	89.03	89.03	0	0	0	0	0	0	0	0
37														
38														
39	C Surcharge Subtotal	-113.17	67.892	86.7 6	89.03	89.03	0	0	0	0	0	0	0	-113.17
40														
41														
42	D Net balance to be recovered (A-B C)	67.892	86,7 6	89,03	89,03	89,03	0	0	0	0	0	0	0	89,03
43														
44	E Allocat on of Lit gated Recovery		0		0	-89,03	0	0	0	0	0	0	0	-89,03
45														
46	6 Surcharge calculation													
47	7 Unrecovered costs (D E)	0	0	0	0	0	0	0	0	0	0	0	0	0
48	8 remaining life	2	36	8	60	72	8	8	8	8	8	8	8	
49	9 one year	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	0	0	0	0	
51														
52	Required annual increase in rates:													
53	53 smal er of D or F	0	0	0	0	0	0	0	0	0	0	0	0	0
54														
55	55 forecas ed them sales	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	179.57 ,679	182,899,057
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

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

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

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Liberty Utilities (EnergyNorth Natural Gas) Corp.  
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Keene												
												DEF055
(9/03 - 9/0 )	(9/0 - 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)	subtotal
_ool #1	_ool #2	_ool #3	_ool #	_ool #5	_ool #6	_ool #7	_ool #8	_ool #9	_ool #10	pool #11	pool #12	
1	1	Remediation costs (i.o. 500061)	0									
		Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	0	0	88	1.00
3	A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	0	0	88	1.00
5		Cash recover es (i.o. 500061)	0									
6		Cash recover es (i.o. 50000 )	0									
7		Recovery costs (i.o. 50000 )	0		18,831	823	0	0	0	0		
8		Transfer Credit from Gas Restructuring	0		0	0	0	0	0	0		
9	B	Subtotal - net recoveries	0	0	18,831	823	0	0	0	0	0	0
11	A-B	Total net expenses to recover	10,165	6,606	53,922	9,589	32	269	0	0	88	1.00
15		Act June 1998 - October 1998	0									-
16		Act November 1998 - October 1999	0									-
17		Act November 1999 - October 2000	0									-
18		Act November 2000 - October 2001	0									-
19		Act November 2001 - October 2002	0									-
20		Act November 2002 - October 2003	0									-
21		Act November 2003 - October 2004	0									-
22		Act November 2004 - October 2005	0	0			0	0	0	0	-	-
23		Act November 2005 - October 2006	0	0			0	0	0	0	-	-
24		Act November 2006 - October 2007	0	0	-1,091	0	0	0	0	0	-	(14,091)
25		Act November 2007 - October 2008	0	0	0	0	0	0	0	0	-	-
26		Act November 2012 - October 2013										-
27		Act November 2013 - October 2014										-
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										-
32		Act Nov 2013-Oct 2014 Base Rate Rev										-
33		Act Nov 2014-Oct 2015 Base Rate Rev										-
34		AES co lections										-
35		Gas Street overcollection										-
36		Pr or Period Pool under/overcollect on	10,165	16,771	56,622	66,211	0	0	0	0	0	-
37												-
38												-
39	C	Surcharge Subtotal	0	10,165	2,680	56,622	66,211	0	0	0	0	(14,091)
40												-
41												-
42	D	Net balance to be recovered (A-B C)	10,165	16,771	56,622	66,211	66,2	269	0	0	88	1.00
43												-
44	E	Allocat on of Lit gated Recovery	0	0	0	0	-66.2	-269	0	0	0	0
45												-
46		Surcharge calculation										-
47		Unrecovered costs (D E)	0	0	0		0	0	0	0	0	0
48		remaining life	2	36	8	60	72	8	8	12	12	12
49		one year	12	12	12	12	12	12	12	12	12	12
50	F	amortization	0	0	0	0	0	0	0	0	0	0
51												-
52		Required annual increase in rates:										-
53		small er of D or F	0	0	0	0	0	0	0	0	0	0
54												-
55		forecas ed them sales	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,574,679
56												179,574,679
57	###	surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	182,899,057

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 Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130  
 Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

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		Concord													DEF077		
		Corrected per 2/08 Audit															
		(9/03 - 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 - 6/1 )	(7/1 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	(7/17 - 6/18)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	\$ total
		pool #1 - #	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	
1	1 Remediation costs (i.o. 500061)	0															
2	2 Remediation costs (i.o. 500005)	397,110	8,006	77,063	9, 03	179,732	289,103	8 ,256	135,673	192,525	11 ,7 9						
3	3 A Subtotal - remediation costs	397,110	8,006	77,063	9, 03	179,732	289,103	8 ,256	135,673	192,525	11 ,7 9						
5	5 Cash recover es (i.o. 500061)	-70,215	-12,601	16,623	-3,213	-11,39	-31,575	-38,871	-12,319	-28,7 2	-19,197						
6	6 Cash recover es (i.o. 50000 )	0															
7	7 Recovery costs (i.o. 50000 )	0	1, 32	-1,007													
8	8 Transfer Credit from Gas Restructuring	0															
9	9 B Subtotal - net recoveries	-70,215	-11,169	15,616	-3,213	-11,39	-31,575	-38,871	-12,319	-28,7 2	-19,197						
10																	
11	11 A-B Total net expenses to recover	326,89	-3,163	92,679	6,190	168,338	257,528	5,38	123,355	163,783	95,553						
12																	
13																	
14	14 Surcharge revenue:																
15	15 Act June 1998 - October 1998	0															
16	16 Act November 1998 - October 1999	0															
17	17 Act November 1999 - October 2000	0															
18	18 Act November 2000 - October 2001	0															
19	19 Act November 2001 - October 2002	0															
20	20 Act November 2002 - October 2003	0															
21	21 Act November 2003 - October 200	0															
22	22 Act November 200 - October 2005	0															
23	23 Act November 2005- October 2006	-27, 99	0	0	0	0	0	0	0	0	0	-	-	-	-	-	(27,499)
24	24 Act November 2006- October 2007	-28,181	0	0	0	0	0	0	0	0	0	-	-	-	-	-	(28,181)
25	25 Act November 2007- October 2008	0															
26	26 Act November 2012- October 2013	0					-20,006	-20,006									
27	27 Act November 2013- October 201	0					-12,7 9	-25, 97									
28	28 Act Nov 2009-Oct 2010 Base Rate Rev	0					-1,891										
29	29 Act Nov 2010-Oct 2011 Base Rate Rev	0					-13,816										
30	30 Act Nov 2011-Oct 2012 Base Rate Rev	0					-12,16										
31	31 Act Nov 2012-Oct 2013 Base Rate Rev	0					-6,79	-6,79									
32	32 Act Nov 2013-Oct 201 Base Rate Rev	0															
33	33 Act Nov 201 -Oct 2015 Base Rate Rev	0															
34	34 AES co lections	0															
35	35 Gas Street overcollection	0															
36	36 Pr or Period Pool under/overcollect on	19,182	271,21	0	0	0	0	0	0	0	0	-	-	-	-	-	-
37																	
38																	
39	39 C Surcharge Subtotal	363,501	271,21	0	0	-67, 20	-52,297	0	0	0	0	-	-	-	-	-	(175,398)
40																	
41																	
42	42 D Net balance to be recovered (A-B C)	690,395	268,051	92,679	6,190	100,919	205,231	5,38	123,355	163,783	95,553						
43																	
44	44 E Allocat on of Lit gated Recovery	0	-268,051	-92,679	- 6,190	-1 ,702	0	0	0	0	0						
45																	
46	46 Surcharge calculation																
47	47 Unrecovered costs (D E)	0	0	0	0	0	0	0	0	23,398	27,301						
48	48 remaining life	1	72	8	8	12	12	12	12	12	2						
49	49 one year	36	12	12	12	12	12	12	12	12	12						
50	50 F amortization	0	0	0	0	0	0	0	0	23,398	13,650						
51																	
52	52 Required annual increase in rates:																
53	53 smal er of D or F	0	0	0	0	0	0	0	0	23,398	13,650						
54																	
55	55 forecas ed them sales	553,96 ,622	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,574,679	179,574,679	179,574,679	179,574,679	182,899,057	182,899,057
56																	
57	### surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0001	\$0.0001						

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



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Liberty Utilities (Energy/Natural Gas) Corp.  
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General																DEF064	2021 MGP		
	(9/02 - 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 - 6/1 )	(7/1 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	(7/17 - 6/18)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	\$ total	Remediat on \$ total		
	ool #1 - #5	ool #6	ool #7	ool #8	ool #9	ool #10	ool #11	ool #12	ool #13	ool #14	ool #15	ool #16	ool #17	ool #18	ool #19				
1	1	Remediation costs (i.o. 500061)																	
2	2	Remediation costs (i.o. 500005)	806,611	-181,000	-26,88	,199	69,286	93,03	75,20	13,139	16,612	11,879	6,5,7	10,799	6,868	7,111	5,6,6	919,051	
3	A	Subtotal - remediation costs	806,611	-181,000	-26,88	,199	69,286	93,03	75,20	13,139	16,612	11,879	6,5,7	10,799	6,868	7,111	5,6,6	919,051	
5	5	Cash recover es (i.o. 500061)	0	0	0													0	
6	6	Cash recover es (i.o. 50000 )																0	
7	7	Recovery costs (i.o. 50000 )		16,012	23,953	0	0	-1,068	-1,358	0	-2,250	0	0	0	0	0	0	288	
8	8	Transfer Credit from Gas Restructuring		-3,331														-3,331	
9	B	Subtotal - net recoveries	0	12,681	23,953	0	0	-1,068	-1,358	0	-2,250	0	0	0	0	0	0	-3,0,3	
10	A-B	Total net expenses to recover	806,611	-188,319	-2,931	,199	69,286	78,967	73,8,6	13,139	-7,638	11,879	6,5,7	10,799	6,868	7,111	5,6,6	916,009	
15	1	Surcharge revenue:																	
16	15	Act June 1998 - October 1998																0 (54,889)	
17	16	Act November 1998 - October 1999																0 (538,143)	
18	17	Act November 1999 - October 2000																0 (912,804)	
19	18	Act November 2000 - October 2001																0 (1,336,776)	
20	19	Act November 2001 - October 2002																0 (1,679,228)	
21	20	Act November 2002 - October 2003																0 (1,732,442)	
22	21	Act November 2003 - October 200	-8,265															-8,265 (1,428,735)	
23	22	Act November 200 - October 2005	-70,898															-70,898 (1,403,877)	
24	23	Act November 2005- October 2006	-96,2,7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-96,2,7 (1,694,877)	
25	24	Act November 2006- October 2007	-9,318	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-9,318 (2,036,113)	
26	25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
27	26	Act November 2012- October 2013	0	0	0	0	-5,002	-5,002	0	0	0	0	0	0	0	0	0	-10,003 (160,048)	
28	27	Act November 2013- October 201					-12,7,9	-12,7,9	-12,7,9									-38,2,6 (293,217)	
29	28	Act Nov 2009-Oct 2010 Base Rate Rev																0 (10,611)	
30	29	Act Nov 2010-Oct 2011 Base Rate Rev																0 (77,509)	
31	30	Act Nov 2011-Oct 2012 Base Rate Rev																0 (68,244)	
32	31	Act Nov 2012-Oct 2013 Base Rate Rev																0 (76,335)	
33	32	Act Nov 2013-Oct 201 Base Rate Rev																0 (85,296)	
34	33	Act Nov 201 -Oct 2015 Base Rate Rev																0 (86,554)	
35	3	AES co lections																0 (266,571)	
36	35	Gas Street overcollection																0 (23,511)	
37	36	Pr or Period Pool under/overcollect on	1,86,6	2,088,527	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
38	C	Surcharge Subtotal	1,261,916	2,088,527	0	0	-17,750	-17,750	-12,7,9	0	0	0	0	0	0	0	0	-272,977 (13,965,693)	
39	D	Net balance to be recovered (A-B C)	2,068,527	1,900,208	-2,931	,199	51,536	61,217	61,098	13,139	-7,638	11,879	6,5,7	10,799	6,868	7,111	5,6,6	6,3,032	
40	E	Allocat on of Lit gated Recovery	0	-1,900,208	2,931	,199	-8,562	0	0	0	0	0	0	0	0	0	0	-1,910,037	
41	F	Surcharge calculation																	
42	7	Unrecovered costs (D E)		0	0	0	0	0	0	-1,091	3,39	2,806	6,171	,906	6,095	5,6,6		27,926	
43	8	remaining life	72	8	8	8	12	12	12	12	2	36	8	60	72	8			
44	9	one year	12	12	12	12	12	12	12	12	12	12	12	12	12	12			
45	50	F amortization	0	0	0	0	0	0	0	-1,091	1,697	935	1,5,3	981	1,016	807			
46	51	Required annual increase in rates:																	
47	52	small er of D or F	0	0	0	0	0	0	0	-1,091	1,697	935	1,5,3	981	1,016	807		5,887	
48	55	forecas ed them sales	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	179,57,679	182,899,057	182,899,057	182,899,057
49	56	### 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	\$0.0129	

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

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

REDACTED  
 Schedule 20.3  
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Liberty Utilities (EnergyNorth Natural Gas) Corp.  
 Environmental Remediation MGPs  
 Tariff page 99

Expense and Collection Summary per Year															Total
	(thru - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9 10 - 9/11)	(9 11 - 9/12)	(7/13 - 6/1 )	(7/1 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	(7/17 - 6/18)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	
1	1 Remediation costs (i.o. 500051)	9,917,388	590,62	518,907	67,766	686,515	993,3	76,206	312,039	220,3	256,871	670,90	397,6	539,32	50,039
2	2 Remediation costs (i.o. 500005)	13,712,581	255,263	658,32	316,280	59,550	651,906	2,605,250	7,975,39	3,307,910	260,380	115,81	69,261	11,228	8,99
3	A Subtotal - remediation costs	23,629,969	8,5,887	1,177,231	991,05	1,16,065	1,653,0	3,081,56	8,287,33	3,528,25	517,250	786,75	66,707	653,552	952,538
5	5 Cash recover es (i.o. 500061)	-2,93,5	-1,150,52	-58,231	-113,390	-310,226	-105,062	-607,70	-121,889	-119,826	-53,116	-195,23	-208,5	-212,660	-169,10
6	6 Cash recover es (i.o. 50000 )	-5,985	0	0	0	0	0	0	0	0	0	0	0	0	0
7	7 Recovery costs (i.o. 50000 )	1,918,30	39,173	22,96	0	0	-1,068	2,500,000	2,75,750	0	0	0	0	0	0
8	8 Transfer Credit from Gas Restructuring	0	-3,331	0	0	0	0	0	0	0	0	0	0	0	0
9	B Subtotal - net recoveries	-1,62,188	-1,11,609	-35,285	-113,390	-310,226	-119,129	1,892,296	2,353,861	-119,826	-53,116	-195,23	-208,5	-212,660	-169,10
11	A-B Total net expenses to recover	22,167,780	3,731,277	1,119,6	877,655	835,839	1,526,211	,973,753	10,61,29	3,08,28	6,13	591,322	258,163	0,892	783,398
15	15 Act June 1998 - October 1998	-5,889	0	0	0	0	0	0	0	0	0	0	0	0	(5,889)
16	16 Act November 1998 - October 1999	-538,13	0	0	0	0	0	0	0	0	0	0	0	0	(538,13)
17	17 Act November 1999 - October 2000	-912,80	0	0	0	0	0	0	0	0	0	0	0	0	(912,80)
18	18 Act November 2000 - October 2001	-1,336,776	0	0	0	0	0	0	0	0	0	0	0	0	(1,336,776)
19	19 Act November 2001 - October 2002	-1,679,228	0	0	0	0	0	0	0	0	0	0	0	0	(1,679,228)
20	20 Act November 2002 - October 2003	-1,732,2	0	0	0	0	0	0	0	0	0	0	0	0	(1,732,2)
21	21 Act November 2003 - October 200	-1,28,735	0	0	0	0	0	0	0	0	0	0	0	0	(1,28,735)
22	22 Act November 200 - October 2005	-1,03,787	0	0	0	0	0	0	0	0	0	0	0	0	(1,03,787)
23	23 Act November 2005 - October 2006	-1,69,877	0	0	0	0	0	0	0	0	0	0	0	0	(1,69,877)
24	24 Act November 2006 - October 2007	-2,036,113	0	0	0	0	0	0	0	0	0	0	0	0	(2,036,113)
25	25 Act November 2007 - October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	26 Act November 2012 - October 2013	0	0	0	0	-30,009	-130,039	0	0	0	0	0	0	0	(160,048)
27	27 Act November 2013 - October 201	0	0	0	0	-38,26	-165,731	-89,20	0	0	0	0	0	0	(293,217)
28	28 Act Nov 2009-Oct 2010 Base Rate Rev	0	0	0	0	-10,611	0	0	0	0	0	0	0	0	(10,611)
29	29 Act Nov 2010-Oct 2011 Base Rate Rev	0	0	0	0	-77,509	0	0	0	0	0	0	0	0	(77,509)
30	30 Act Nov 2011-Oct 2012 Base Rate Rev	0	0	0	0	-68,2	0	0	0	0	0	0	0	0	(68,2)
31	31 Act Nov 2012-Oct 2013 Base Rate Rev	0	0	0	0	-8,937	-67,398	0	0	0	0	0	0	0	(76,335)
32	32 Act Nov 2013-Oct 201 Base Rate Rev	0	0	0	0	0	-28,33	-56,865	0	0	0	0	0	0	(85,298)
33	33 Act Nov 201 -Oct 2015 Base Rate Rev	0	0	0	0	0	-21,639	-3,277	-21,639	0	0	0	0	0	(86,55)
34	34 AES oo lections	-69,391	-12,620	-12,90	-13,15	-13,221	-13,738	-27,673	-1,173	-1,05	-1,66	-1,858	-1,999	-15,312	-15,68
35	35 Gas Street overcollection	-23,511	0	0	0	0	0	0	0	0	0	0	0	0	(23,511)
36	36 Pr or Period Pool under/overcollect on	15,673,57	0	0	0	0	0	0	0	0	0	0	0	0	0
37	37														
38	38														
39	39 C Surcharge Subtotal	2,762,851	-12,620	-12,90	-13,15	-2,6,777	-26,978	-217,055	-35,811	-1,05	-1,66	-1,858	-1,999	-15,312	-15,68
40	40														
41	41 D Net balance to be recovered (A-B C)	2,930,631	3,718,657	1,129,02	86,510	589,062	1,099,233	,756,698	10,605,83	3,39,023	9,70	576,6	2,3,165	25,579	767,930
42	42														
43	43 E Allocat on of Lit gated Recovery														
44	44														
45	45 Surcharge calculation														
46	46 Unrecovered costs (D E)														
47	47 remaining life														
48	48 one year														
49	49 F amortization														
50	50														
51	51 Required annual increase in rates:														
52	52 smaller of D or F														
53	53														
54	54 forecasted them sales														
55	55														
56	56														
57	57 surcharge per therm														

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

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

**Calculation of Supplier Balancing Charge  
2020-2021**

**Rate: \$ 0.1807 /MMBtu**

	<b>Rate</b>	<b>Volume</b>	<b>Total</b>
Injection Cost	\$ 0.0087	<b>386,014</b>	\$ 3,358
Fuel 1.75%	\$ 0.0481	<b>386,014</b>	\$ 18,577
Withdrawal Cost	\$ 0.0087	<b>195,768</b>	\$ 1,703
Delivery Rate	\$ 0.0431	195,768	\$ 8,432
FTA Demand Charge	\$ 0.2357	195,768	\$ 46,138
FTA Commodity Charge	\$ 0.1003	195,768	\$ 19,636
Fuel 1.35%	\$ 0.0371	195,768	\$ 7,268
		<b>Total Cost</b>	<b>\$ 105,112</b>
	<b>Absolute Value of the</b>	<b>Sendout Error</b>	<b>581,782</b> MMBtu
		<b>Rate</b>	<b>\$ 0.1807 /MMBTU</b>

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	\$	1.3094	/ MMBtu per month
	\$	0.0431	/ MMBtu per day
TGP Z4-6 Demand Charge	\$	7.1645	/ MMBtu per month
	\$	0.2357	/ MMBtu per day
TGP Z4-6 Commodity Charge	\$	0.1003	/ MMBtu

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

Calculation of Supplier Balancing Charge  
2020-2021  
Estimated Monthly Imbalances

<u>Date</u>	<u>Forecasted</u> <u>DD</u>	<u>Actual</u> <u>DD</u>	<u>Forecaster</u> <u>Error</u> <u>DD</u>	<u>Forecasted</u> <u>Sendout</u> <u>(MMBtu)</u>	<u>Actual</u> <u>Sendout</u> <u>(MMBtu)</u>	<u>Sendout</u> <u>Error</u> <u>(MMBtu)</u>	<u>Abs.Value</u> <u>Sendout</u> <u>Error</u> <u>(MMBtu)</u>	<u>Injections</u> <u>(MMBtu)</u>	<u>Withdrawals</u> <u>(MMBtu)</u>
Nov	599	589	10	1,423,420	1,408,975	14,445	66,447	40,446	26,001
Dec	986	997	(11)	2,217,499	2,237,310	(19,812)	84,649	32,419	52,230
Jan	1,122	1,118	4	2,564,525	2,556,052	8,473	84,733	46,603	38,130
Feb	1,086	1,059	27	2,484,194	2,438,118	46,075	86,870	66,473	20,397
Mar	731	724	7	1,759,139	1,745,972	13,168	69,602	41,385	28,217
Apr	595	568	27	1,279,771	1,242,675	37,097	53,584	45,340	8,244
May	262	237	25	685,310	660,496	24,814	34,740	29,777	4,963
Jun	32	21	11	221,781	216,450	5,330	7,269	6,300	969
Jul	-	-	-	432,376	432,376	-	-	-	-
Aug	15	5	10	324,442	316,893	7,549	7,549	7,549	-
Sep	105	78	27	415,806	401,671	14,135	16,155	15,145	1,010
Oct	446	407	39	906,155	867,184	38,971	70,184	54,578	15,607
<b>Total</b>	<b>5,979</b>	<b>5,803</b>	<b>176</b>	<b>14,714,420</b>	<b>14,524,173</b>	<b>190,246</b>	<b>581,782</b>	<b>386,014</b>	<b>195,768</b>

**Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
Calculation of Supplier Balancing Charge  
2021-2022  
Estimated Daily Imbalances**

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value	Injections (MMBtu)	Withdrawals (MMBtu)
							Sendout Error (MMBtu)		
Apr 1, 2020	24	21	3	48383.82627	44261.97983	4121.846436	4121.846436	4121.846436	0
Apr 2, 2020	21	22	-1	44261.97983	45635.92864	-1373.94881	1373.948812	0	1373.948812
Apr 3, 2020	20	20	0	42888.03102	42888.03102	0	0	0	0
Apr 4, 2020	21	18	3	44261.97983	40140.1334	4121.846436	4121.846436	4121.846436	0
Apr 5, 2020	13	14	-1	33270.38934	34644.33815	-1373.94881	1373.948812	0	1373.948812
Apr 6, 2020	17	16	1	38766.18458	37392.23577	1373.948812	1373.948812	1373.948812	0
Apr 7, 2020	15	12	3	36018.28696	31896.44052	4121.846436	4121.846436	4121.846436	0
Apr 8, 2020	17	18	-1	38766.18458	40140.1334	-1373.94881	1373.948812	0	1373.948812
Apr 9, 2020	22	23	-1	45635.92864	47009.87745	-1373.94881	1373.948812	0	1373.948812
Apr 10, 2020	24	24	0	48383.82627	48383.82627	0	0	0	0
Apr 11, 2020	23	23	0	47009.87745	47009.87745	0	0	0	0
Apr 12, 2020	10	10	0	29148.5429	29148.5429	0	0	0	0
Apr 13, 2020	13	10	3	33270.38934	29148.5429	4121.846436	4121.846436	4121.846436	0
Apr 14, 2020	18	15	3	40140.1334	36018.28696	4121.846436	4121.846436	4121.846436	0
Apr 15, 2020	24	23	1	48383.82627	47009.87745	1373.948812	1373.948812	1373.948812	0
Apr 16, 2020	27	27	0	52505.6727	52505.6727	0	0	0	0
Apr 17, 2020	22	23	-1	45635.92864	47009.87745	-1373.94881	1373.948812	0	1373.948812
Apr 18, 2020	26	27	-1	51131.72389	52505.6727	-1373.94881	1373.948812	0	1373.948812
Apr 19, 2020	13	11	2	33270.38934	30522.49171	2747.897624	2747.897624	2747.897624	0
Apr 20, 2020	21	21	0	44261.97983	44261.97983	0	0	0	0
Apr 21, 2020	24	24	0	48383.82627	48383.82627	0	0	0	0
Apr 22, 2020	26	26	0	51131.72389	51131.72389	0	0	0	0
Apr 23, 2020	20	17	3	42888.03102	38766.18458	4121.846436	4121.846436	4121.846436	0
Apr 24, 2020	23	18	5	47009.87745	40140.1334	6869.744059	6869.744059	6869.744059	0
Apr 25, 2020	13	11	2	33270.38934	30522.49171	2747.897624	2747.897624	2747.897624	0
Apr 26, 2020	21	21	0	44261.97983	44261.97983	0	0	0	0
Apr 27, 2020	26	24	2	51131.72389	48383.82627	2747.897624	2747.897624	2747.897624	0
Apr 28, 2020	19	18	1	41514.08221	40140.1334	1373.948812	1373.948812	1373.948812	0
Apr 29, 2020	15	15	0	36018.28696	36018.28696	0	0	0	0
Apr 30, 2020	17	16	1	38766.18458	37392.23577	1373.948812	1373.948812	1373.948812	0
May 1, 2020	10	9	1	23643.67895	22651.10414	992.5748165	992.5748165	992.5748165	0
May 2, 2020	7	3	4	20665.9545	16695.65524	3970.299266	3970.299266	3970.299266	0
May 3, 2020	1	0	1	14710.50561	13717.93079	992.5748165	992.5748165	992.5748165	0
May 4, 2020	14	12	2	27613.97822	25628.82859	1985.149633	1985.149633	1985.149633	0
May 5, 2020	17	17	0	30591.70267	30591.70267	0	0	0	0
May 6, 2020	15	13	2	28606.55304	26621.4034	1985.149633	1985.149633	1985.149633	0
May 7, 2020	12	10	2	25628.82859	23643.67895	1985.149633	1985.149633	1985.149633	0
May 8, 2020	18	18	0	31584.27749	31584.27749	0	0	0	0
May 9, 2020	24	25	-1	37539.72639	38532.3012	-992.574817	992.5748165	0	992.5748165
May 10, 2020	16	15	1	29599.12785	28606.55304	992.5748165	992.5748165	992.5748165	0
May 11, 2020	15	14	1	28606.55304	27613.97822	992.5748165	992.5748165	992.5748165	0
May 12, 2020	18	18	0	31584.27749	31584.27749	0	0	0	0
May 13, 2020	15	14	1	28606.55304	27613.97822	992.5748165	992.5748165	992.5748165	0
May 14, 2020	6	2	4	19673.37969	15703.08042	3970.299266	3970.299266	3970.299266	0
May 15, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 16, 2020	4	7	-3	17688.23006	20665.9545	-2977.72445	2977.72445	0	2977.72445
May 17, 2020	4	2	2	17688.23006	15703.08042	1985.149633	1985.149633	1985.149633	0
May 18, 2020	9	7	2	22651.10414	20665.9545	1985.149633	1985.149633	1985.149633	0
May 19, 2020	10	10	0	23643.67895	23643.67895	0	0	0	0
May 20, 2020	8	7	1	21658.52932	20665.9545	992.5748165	992.5748165	992.5748165	0
May 21, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 22, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 23, 2020	12	10	2	25628.82859	23643.67895	1985.149633	1985.149633	1985.149633	0
May 24, 2020	11	9	2	24636.25377	22651.10414	1985.149633	1985.149633	1985.149633	0
May 25, 2020	3	4	-1	16695.65524	17688.23006	-992.574817	992.5748165	0	992.5748165
May 26, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 27, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 28, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 29, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 30, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 31, 2020	13	11	2	26621.4034	24636.25377	1985.149633	1985.149633	1985.149633	0
Jun 1, 2020	10	10	0	16305.53853	16305.53853	0	0	0	0
Jun 2, 2020	3	2	1	12913.42533	12428.83773	484.5875993	484.5875993	484.5875993	0
Jun 3, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 4, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 5, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.  
Calculation of Supplier Balancing Charge  
2019-2020

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value	Injections (MMBtu)	Withdrawals (MMBtu)
							Sendout Error (MMBtu)		
Jun 6, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 7, 2020	5	2	3	13882.60053	12428.83773	1453.762798	1453.762798	1453.762798	0
Jun 8, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 9, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 10, 2020	0	1	-1	11459.66253	11944.25013	-484.587599	484.5875993	0	484.5875993
Jun 11, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 12, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 13, 2020	3	4	-1	12913.42533	13398.01293	-484.587599	484.5875993	0	484.5875993
Jun 14, 2020	6	2	4	14367.18813	12428.83773	1938.350397	1938.350397	1938.350397	0
Jun 15, 2020	3	0	3	12913.42533	11459.66253	1453.762798	1453.762798	1453.762798	0
Jun 16, 2020	2	0	2	12428.83773	11459.66253	969.1751986	969.1751986	969.1751986	0
Jun 17, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 18, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 19, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 20, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 21, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 22, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 23, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 24, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 25, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 26, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 27, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 28, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 29, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 30, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jul 1, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 2, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 3, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 4, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 5, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 6, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 7, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 8, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 9, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 10, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 11, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 12, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 13, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 14, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 15, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 16, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 17, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 18, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 19, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 20, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 21, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 22, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 23, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 24, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 25, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 26, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 27, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 28, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 29, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 30, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 31, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Aug 1, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 2, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 3, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 4, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 5, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 6, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 7, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 8, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 9, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 10, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 11, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.  
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2019-2020  
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value	Injections (MMBtu)	Withdrawals (MMBtu)
							Sendout Error (MMBtu)		
Aug 12, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 13, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 14, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 15, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 16, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 17, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 18, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 19, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 20, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 21, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 22, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 23, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 24, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 25, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 26, 2020	5	1	4	13884.05439	10864.54385	3019.510544	3019.510544	3019.510544	0
Aug 27, 2020	6	2	4	14638.93203	11619.42148	3019.510544	3019.510544	3019.510544	0
Aug 28, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 29, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 30, 2020	4	2	2	13129.17676	11619.42148	1509.755272	1509.755272	1509.755272	0
Aug 31, 2020	2	0	2	11619.42148	10109.66621	1509.755272	1509.755272	1509.755272	0
Sep 1, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 2, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 3, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 4, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 5, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 6, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 7, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 8, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 9, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 10, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 11, 2020	7	4	3	15678.88572	14163.85588	1515.029842	1515.029842	1515.029842	0
Sep 12, 2020	8	5	3	16183.89567	14668.86583	1515.029842	1515.029842	1515.029842	0
Sep 13, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 14, 2020	8	5	3	16183.89567	14668.86583	1515.029842	1515.029842	1515.029842	0
Sep 15, 2020	6	8	-2	15173.87577	16183.89567	-1010.019895	1010.019895	0	1010.019895
Sep 16, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 17, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 18, 2020	12	10	2	18203.93546	17193.91556	1010.019895	1010.019895	1010.019895	0
Sep 19, 2020	16	13	3	20223.97525	18708.94541	1515.029842	1515.029842	1515.029842	0
Sep 20, 2020	17	14	3	20728.9852	19213.95535	1515.029842	1515.029842	1515.029842	0
Sep 21, 2020	14	14	0	19213.95535	19213.95535	0	0	0	0
Sep 22, 2020	8	4	4	16183.89567	14163.85588	2020.03979	2020.03979	2020.03979	0
Sep 23, 2020	2	0	2	13153.83598	12143.81609	1010.019895	1010.019895	1010.019895	0
Sep 24, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 25, 2020	1	1	0	12648.82604	12648.82604	0	0	0	0
Sep 26, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 27, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 28, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 29, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 30, 2020	6	3	3	15173.87577	13658.84593	1515.029842	1515.029842	1515.029842	0
Oct 1, 2020	5	3	2	19175.97949	17095.09572	2080.883772	2080.883772	2080.883772	0
Oct 2, 2020	15	14	1	29580.39835	28539.95646	1040.441886	1040.441886	1040.441886	0
Oct 3, 2020	12	12	0	26459.07269	26459.07269	0	0	0	0
Oct 4, 2020	12	10	2	26459.07269	24378.18892	2080.883772	2080.883772	2080.883772	0
Oct 5, 2020	11	8	3	25418.6308	22297.30515	3121.325658	3121.325658	3121.325658	0
Oct 6, 2020	6	4	2	20216.42137	18135.5376	2080.883772	2080.883772	2080.883772	0
Oct 7, 2020	9	5	4	23337.74703	19175.97949	4161.767544	4161.767544	4161.767544	0
Oct 8, 2020	18	16	2	32701.72401	30620.84024	2080.883772	2080.883772	2080.883772	0
Oct 9, 2020	12	9	3	26459.07269	23337.74703	3121.325658	3121.325658	3121.325658	0
Oct 10, 2020	4	0	4	18135.5376	13973.77006	4161.767544	4161.767544	4161.767544	0
Oct 11, 2020	16	14	2	30620.84024	28539.95646	2080.883772	2080.883772	2080.883772	0
Oct 12, 2020	15	14	1	29580.39835	28539.95646	1040.441886	1040.441886	1040.441886	0
Oct 13, 2020	13	13	0	27499.51458	27499.51458	0	0	0	0
Oct 14, 2020	10	10	0	24378.18892	24378.18892	0	0	0	0
Oct 15, 2020	5	0	5	19175.97949	13973.77006	5202.20943	5202.20943	5202.20943	0
Oct 16, 2020	14	15	-1	28539.95646	29580.39835	-1040.44189	1040.441886	0	1040.441886
Oct 17, 2020	21	21	0	35823.04967	35823.04967	0	0	0	0

**Liberty Utilities (EnergyNorth Natural Gas) Corp.  
Calculation of Supplier Balancing Charge  
2019-2020  
Estimated Daily Imbalances**

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value	Injections (MMBtu)	Withdrawals (MMBtu)
							Sendout Error (MMBtu)		
Oct 18, 2020	17	17	0	31661.28212	31661.28212	0	0	0	0
Oct 19, 2020	13	9	4	27499.51458	23337.74703	4161.767544	4161.767544	4161.767544	0
Oct 20, 2020	7	3	4	21256.86326	17095.09572	4161.767544	4161.767544	4161.767544	0
Oct 21, 2020	4	3	1	18135.5376	17095.09572	1040.441886	1040.441886	1040.441886	0
Oct 22, 2020	7	4	3	21256.86326	18135.5376	3121.325658	3121.325658	3121.325658	0
Oct 23, 2020	8	5	3	22297.30515	19175.97949	3121.325658	3121.325658	3121.325658	0
Oct 24, 2020	16	14	2	30620.84024	28539.95646	2080.883772	2080.883772	2080.883772	0
Oct 25, 2020	21	21	0	35823.04967	35823.04967	0	0	0	0
Oct 26, 2020	16	18	-2	30620.84024	32701.72401	-2080.88377	2080.883772	0	2080.883772
Oct 27, 2020	21	19	2	35823.04967	33742.16589	2080.883772	2080.883772	2080.883772	0
Oct 28, 2020	22	22	0	36863.49155	36863.49155	0	0	0	0
Oct 29, 2020	25	36	-11	39984.81721	51429.67796	-11444.8607	11444.86075	0	11444.86075
Oct 30, 2020	35	36	-1	50389.23607	51429.67796	-1040.44189	1040.441886	0	1040.441886
Oct 31, 2020	30	29	1	45187.02664	44146.58475	1040.441886	1040.441886	1040.441886	0
Nov 1, 2020	21	20	1	48939.99847	47495.49736	1444.501114	1444.501114	1444.501114	0
Nov 2, 2020	29	29	0	60496.00739	60496.00739	0	0	0	0
Nov 3, 2020	31	30	1	63385.00961	61940.5085	1444.501114	1444.501114	1444.501114	0
Nov 4, 2020	20	20	0	47495.49736	47495.49736	0	0	0	0
Nov 5, 2020	9	4	5	31605.9851	24383.47953	7222.505571	7222.505571	7222.505571	0
Nov 6, 2020	7	5	2	28716.98287	25827.98065	2889.002228	2889.002228	2889.002228	0
Nov 7, 2020	6	7	-1	27272.48176	28716.98287	-1444.50111	1444.501114	0	1444.501114
Nov 8, 2020	10	10	0	33050.48622	33050.48622	0	0	0	0
Nov 9, 2020	9	10	-1	31605.9851	33050.48622	-1444.50111	1444.501114	0	1444.501114
Nov 10, 2020	2	0	2	21494.4773	18605.47508	2889.002228	2889.002228	2889.002228	0
Nov 11, 2020	2	0	2	21494.4773	18605.47508	2889.002228	2889.002228	2889.002228	0
Nov 12, 2020	18	19	-1	44606.49513	46050.99624	-1444.50111	1444.501114	0	1444.501114
Nov 13, 2020	25	27	-2	54718.00293	57607.00516	-2889.00223	2889.002228	0	2889.002228
Nov 14, 2020	27	28	-1	57607.00516	59051.50627	-1444.50111	1444.501114	0	1444.501114
Nov 15, 2020	19	18	1	46050.99624	44606.49513	1444.501114	1444.501114	1444.501114	0
Nov 16, 2020	23	23	0	51829.0007	51829.0007	0	0	0	0
Nov 17, 2020	29	29	0	60496.00739	60496.00739	0	0	0	0
Nov 18, 2020	40	40	0	76385.51964	76385.51964	0	0	0	0
Nov 19, 2020	25	23	2	54718.00293	51829.0007	2889.002228	2889.002228	2889.002228	0
Nov 20, 2020	16	14	2	41717.4929	38828.49067	2889.002228	2889.002228	2889.002228	0
Nov 21, 2020	25	22	3	54718.00293	50384.49959	4333.503342	4333.503342	4333.503342	0
Nov 22, 2020	21	22	-1	48939.99847	50384.49959	-1444.50111	1444.501114	0	1444.501114
Nov 23, 2020	27	25	2	57607.00516	54718.00293	2889.002228	2889.002228	2889.002228	0
Nov 24, 2020	34	33	1	67718.51296	66274.01184	1444.501114	1444.501114	1444.501114	0
Nov 25, 2020	24	29	-5	53273.50181	60496.00739	-7222.50557	7222.505571	0	7222.505571
Nov 26, 2020	21	25	-4	48939.99847	54718.00293	-5778.00446	5778.004457	0	5778.004457
Nov 27, 2020	20	20	0	47495.49736	47495.49736	0	0	0	0
Nov 28, 2020	24	25	-1	53273.50181	54718.00293	-1444.50111	1444.501114	0	1444.501114
Nov 29, 2020	25	26	-1	54718.00293	56162.50404	-1444.50111	1444.501114	0	1444.501114
Nov 30, 2020	10	6	4	33050.48622	27272.48176	5778.004457	5778.004457	5778.004457	0
Dec 1, 2020	20	18	2	50268.23604	46666.1398	3602.096234	3602.096234	3602.096234	0
Dec 2, 2020	29	28	1	66477.66909	64676.62097	1801.048117	1801.048117	1801.048117	0
Dec 3, 2020	25	23	2	59273.47662	55671.38039	3602.096234	3602.096234	3602.096234	0
Dec 4, 2020	21	21	0	52069.28415	52069.28415	0	0	0	0
Dec 5, 2020	30	31	-1	68278.71721	70079.76533	-1801.04812	1801.048117	0	1801.048117
Dec 6, 2020	34	35	-1	75482.90968	77283.95779	-1801.04812	1801.048117	0	1801.048117
Dec 7, 2020	35	37	-2	77283.95779	80886.05403	-3602.09623	3602.096234	0	3602.096234
Dec 8, 2020	38	38	0	82687.10214	82687.10214	0	0	0	0
Dec 9, 2020	33	32	1	73681.86156	71880.81344	1801.048117	1801.048117	1801.048117	0
Dec 10, 2020	31	32	-1	70079.76533	71880.81344	-1801.04812	1801.048117	0	1801.048117
Dec 11, 2020	27	29	-2	62875.57286	66477.66909	-3602.09623	3602.096234	0	3602.096234
Dec 12, 2020	24	27	-3	57472.42851	62875.57286	-5403.14435	5403.144351	0	5403.144351
Dec 13, 2020	25	36	-11	59273.47662	79085.00591	-19811.5293	19811.52929	0	19811.52929
Dec 14, 2020	33	31	2	73681.86156	70079.76533	3602.096234	3602.096234	3602.096234	0
Dec 15, 2020	42	43	-1	89891.29461	91692.34273	-1801.04812	1801.048117	0	1801.048117
Dec 16, 2020	43	44	-1	91692.34273	93493.39085	-1801.04812	1801.048117	0	1801.048117
Dec 17, 2020	45	42	3	95294.43896	89891.29461	5403.144351	5403.144351	5403.144351	0
Dec 18, 2020	45	47	-2	95294.43896	98896.5352	-3602.09623	3602.096234	0	3602.096234
Dec 19, 2020	41	42	-1	88090.2465	89891.29461	-1801.04812	1801.048117	0	1801.048117
Dec 20, 2020	34	36	-2	75482.90968	79085.00591	-3602.09623	3602.096234	0	3602.096234
Dec 21, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0
Dec 22, 2020	34	29	5	75482.90968	66477.66909	9005.240585	9005.240585	9005.240585	0
Dec 23, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0



Liberty Utilities (EnergyNorth Natural Gas) Corp.  
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Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value		Injections (MMBtu)	Withdrawals (MMBtu)
							Sendout	Error		
Dec 24, 2020	13	13	0	37660.89922	37660.89922	0	0	0	0	0
Dec 25, 2020	20	19	1	50268.23604	48467.18792	1801.048117	1801.048117	1801.048117	1801.048117	0
Dec 26, 2020	36	35	1	79085.00591	77283.95779	1801.048117	1801.048117	1801.048117	1801.048117	0
Dec 27, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0	0
Dec 28, 2020	28	28	0	64676.62097	64676.62097	0	0	0	0	0
Dec 29, 2020	39	39	0	84488.15026	84488.15026	0	0	0	0	0
Dec 30, 2020	27	28	-1	62875.57286	64676.62097	-1801.04812	1801.048117	0	1801.048117	0
Dec 31, 2020	32	32	0	71880.81344	71880.81344	0	0	0	0	0
Jan 1, 2021	30	31	-1	69606.61887	71724.95338	-2118.3345	2118.334502	0	2118.334502	0
Jan 2, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0	0
Jan 3, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502	0
Jan 4, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	2118.334502	0
Jan 5, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0	0
Jan 6, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502	0
Jan 7, 2021	35	35	0	80198.29138	80198.29138	0	0	0	0	0
Jan 8, 2021	36	36	0	82316.62588	82316.62588	0	0	0	0	0
Jan 9, 2021	37	35	2	84434.96038	80198.29138	4236.669003	4236.669003	4236.669003	4236.669003	0
Jan 10, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003	0
Jan 11, 2021	35	36	-1	80198.29138	82316.62588	-2118.3345	2118.334502	0	2118.334502	0
Jan 12, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	4236.669003	0
Jan 13, 2021	33	31	2	75961.62238	71724.95338	4236.669003	4236.669003	4236.669003	4236.669003	0
Jan 14, 2021	32	31	1	73843.28788	71724.95338	2118.334502	2118.334502	2118.334502	2118.334502	0
Jan 15, 2021	28	26	2	65369.94987	61133.28087	4236.669003	4236.669003	4236.669003	4236.669003	0
Jan 16, 2021	27	24	3	63251.61537	56896.61186	6355.003505	6355.003505	6355.003505	6355.003505	0
Jan 17, 2021	29	25	4	67488.28437	59014.94637	8473.338006	8473.338006	8473.338006	8473.338006	0
Jan 18, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	2118.334502	0
Jan 19, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	2118.334502	0
Jan 20, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502	0
Jan 21, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003	0
Jan 22, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	2118.334502	0
Jan 23, 2021	46	46	0	103499.9709	103499.9709	0	0	0	0	0
Jan 24, 2021	43	43	0	97144.96739	97144.96739	0	0	0	0	0
Jan 25, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502	0
Jan 26, 2021	34	36	-2	78079.95688	82316.62588	-4236.669	4236.669003	0	4236.669003	0
Jan 27, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	4236.669003	0
Jan 28, 2021	47	47	0	105618.3054	105618.3054	0	0	0	0	0
Jan 29, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003	0
Jan 30, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003	0
Jan 31, 2021	46	48	-2	103499.9709	107736.6399	-4236.669	4236.669003	0	4236.669003	0
Feb 1, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0	0
Feb 2, 2021	36	33	3	83276.32165	78176.98524	5099.336415	5099.336415	5099.336415	5099.336415	0
Feb 3, 2021	35	32	3	81576.54285	76477.20643	5099.336415	5099.336415	5099.336415	5099.336415	0
Feb 4, 2021	37	39	-2	84976.10046	88375.65807	-3399.55761	3399.55761	0	3399.55761	0
Feb 5, 2021	32	36	-4	76477.20643	83276.32165	-6799.11522	6799.11522	0	6799.11522	0
Feb 6, 2021	39	37	2	88375.65807	84976.10046	3399.55761	3399.55761	3399.55761	3399.55761	0
Feb 7, 2021	37	40	-3	84976.10046	90075.43687	-5099.33642	5099.336415	0	5099.336415	0
Feb 8, 2021	46	45	1	100274.1097	98574.3309	1699.778805	1699.778805	1699.778805	1699.778805	0
Feb 9, 2021	45	45	0	98574.3309	98574.3309	0	0	0	0	0
Feb 10, 2021	43	43	0	95174.77329	95174.77329	0	0	0	0	0
Feb 11, 2021	49	47	2	105373.4461	101973.8885	3399.55761	3399.55761	3399.55761	3399.55761	0
Feb 12, 2021	49	46	3	105373.4461	100274.1097	5099.336415	5099.336415	5099.336415	5099.336415	0
Feb 13, 2021	42	38	4	93474.99448	86675.87926	6799.11522	6799.11522	6799.11522	6799.11522	0
Feb 14, 2021	38	36	2	86675.87926	83276.32165	3399.55761	3399.55761	3399.55761	3399.55761	0
Feb 15, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0	0
Feb 16, 2021	36	35	1	83276.32165	81576.54285	1699.778805	1699.778805	1699.778805	1699.778805	0
Feb 17, 2021	43	41	2	95174.77329	91775.21568	3399.55761	3399.55761	3399.55761	3399.55761	0
Feb 18, 2021	38	39	-1	86675.87926	88375.65807	-1699.77881	1699.778805	0	1699.778805	0
Feb 19, 2021	38	38	0	86675.87926	86675.87926	0	0	0	0	0
Feb 20, 2021	40	41	-1	90075.43687	91775.21568	-1699.77881	1699.778805	0	1699.778805	0
Feb 21, 2021	42	42	0	93474.99448	93474.99448	0	0	0	0	0
Feb 22, 2021	33	31	2	78176.98524	74777.42763	3399.55761	3399.55761	3399.55761	3399.55761	0
Feb 23, 2021	27	26	1	67978.31241	66278.5336	1699.778805	1699.778805	1699.778805	1699.778805	0
Feb 24, 2021	25	20	5	64578.7548	56079.86077	8498.894025	8498.894025	8498.894025	8498.894025	0
Feb 25, 2021	37	32	5	84976.10046	76477.20643	8498.894025	8498.894025	8498.894025	8498.894025	0
Feb 26, 2021	35	33	2	81576.54285	78176.98524	3399.55761	3399.55761	3399.55761	3399.55761	0
Feb 27, 2021	29	30	-1	71377.87002	73077.64882	-1699.77881	1699.778805	0	1699.778805	0
Feb 28, 2021	26	26	0	66278.5336	66278.5336	0	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.  
Calculation of Supplier Balancing Charge  
2019-2020  
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value	Injections (MMBtu)	Withdrawals (MMBtu)
							Sendout Error (MMBtu)		
Mar 1, 2021	39	38	1	86165.16337	84284.03473	1881.128637	1881.128637	1881.128637	0
Mar 2, 2021	41	41	0	89927.42064	89927.42064	0	0	0	0
Mar 3, 2021	29	28	1	67353.87699	65472.74835	1881.128637	1881.128637	1881.128637	0
Mar 4, 2021	38	38	0	84284.03473	84284.03473	0	0	0	0
Mar 5, 2021	42	41	1	91808.54928	89927.42064	1881.128637	1881.128637	1881.128637	0
Mar 6, 2021	42	40	2	91808.54928	88046.292	3762.257275	3762.257275	3762.257275	0
Mar 7, 2021	40	37	3	88046.292	82402.90609	5643.385912	5643.385912	5643.385912	0
Mar 8, 2021	32	30	2	72997.2629	69235.00563	3762.257275	3762.257275	3762.257275	0
Mar 9, 2021	26	24	2	61710.49108	57948.23381	3762.257275	3762.257275	3762.257275	0
Mar 10, 2021	21	20	1	52304.84789	50423.71926	1881.128637	1881.128637	1881.128637	0
Mar 11, 2021	8	5	3	27850.17561	22206.78969	5643.385912	5643.385912	5643.385912	0
Mar 12, 2021	22	20	2	54185.97653	50423.71926	3762.257275	3762.257275	3762.257275	0
Mar 13, 2021	28	28	0	65472.74835	65472.74835	0	0	0	0
Mar 14, 2021	38	40	-2	84284.03473	88046.292	-3762.25727	3762.257275	0	3762.257275
Mar 15, 2021	43	45	-2	93689.67792	97451.93519	-3762.25727	3762.257275	0	3762.257275
Mar 16, 2021	31	31	0	71116.13427	71116.13427	0	0	0	0
Mar 17, 2021	21	21	0	52304.84789	52304.84789	0	0	0	0
Mar 18, 2021	24	27	-3	57948.23381	63591.61972	-5643.38591	5643.385912	0	5643.385912
Mar 19, 2021	32	32	0	72997.2629	72997.2629	0	0	0	0
Mar 20, 2021	22	23	-1	54185.97653	56067.10517	-1881.12864	1881.128637	0	1881.128637
Mar 21, 2021	17	18	-1	44780.33334	46661.46198	-1881.12864	1881.128637	0	1881.128637
Mar 22, 2021	16	16	0	42899.20471	42899.20471	0	0	0	0
Mar 23, 2021	13	12	1	37255.81879	35374.69016	1881.128637	1881.128637	1881.128637	0
Mar 24, 2021	11	11	0	33493.56152	33493.56152	0	0	0	0
Mar 25, 2021	7	6	1	25969.04697	24087.91833	1881.128637	1881.128637	1881.128637	0
Mar 26, 2021	7	7	0	25969.04697	25969.04697	0	0	0	0
Mar 27, 2021	16	17	-1	42899.20471	44780.33334	-1881.12864	1881.128637	0	1881.128637
Mar 28, 2021	17	20	-3	44780.33334	50423.71926	-5643.38591	5643.385912	0	5643.385912
Mar 29, 2021	25	24	1	59829.36244	57948.23381	1881.128637	1881.128637	1881.128637	0
Mar 30, 2021	15	13	2	41018.07607	37255.81879	3762.257275	3762.257275	3762.257275	0
Mar 31, 2021	7	9	-2	25969.04697	29731.30424	-3762.25727	3762.257275	0	3762.257275
Apr	595	568	27	1279771	1242675	37097	53584	45340	8244
May	262	237	25	685310	660496	24814	34740	29777	4963
Jun	32	21	11	359297	353966	5330	7269	6300	969
Jul	0	0	0	304689	304689	0	0	0	0
Aug	17	5	12	326233	317174	9059	9059	9059	0
Sep	109	81	28	419361	405220	14140	16160	15150	1010
Oct	440	404	36	890981	853525	37456	68669	53063	15607
Nov	599	589	10	1423420	1408975	14445	66447	40446	26001
Dec	986	997	-11	2217499	2237310	-19812	84649	32419	52230
Jan	1122	1118	4	2564525	2556052	8473	84733	46603	38130
Feb	1047	1021	26	2398028	2353834	44194	84989	64592	20397
Mar	770	762	8	1845305	1830256	15049	71483	43266	28217
Total	5,979	5,803	176	14,714,419	14,524,172	190,245	581,782	386,015	195,768

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

**Docket DE 98-124 Gas Restructuring  
Peaking Demand Rate**

Source:

1	Peak Day		171,602	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) 358905	40,000		
		TGP FT-A (Z6-Z6) 72694	30,000		
10			119,718	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		23,769	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23	Gas Supply		\$ 4,119,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		\$ 3,685,458		Summary Page Line 68
26	Granite Ridge		\$ -		Attachment B Page 3 Line 1
27	Total		\$ 7,804,458		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		\$ 328.35		Line 27 divided by Line 20
30					
31	<b>Monthly Peaking MDQ</b>		<b>\$ 54.72</b>	<b>/Dekatherm</b>	Line 29 divided by 6 month

**Tennessee Allocations:**

Resource Type	High Load Factor	Low Load Factor
Pipeline	76.2%	69.1%
Storage	12.9%	16.8%
Peaking	10.9%	14.1%
TOTAL:	100.00%	100.00%

**Capacity Resources effective November 1, 2020\*:**

\*proposed

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate \$/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed	
<b>Pipeline</b>	TCPL + Union	FT to Parkway & IGTS	M12200 & 41232	4,000		\$13.6260		10/31/2026		
	Iroquois	RTS to Wright	470-01	4,047		\$5.2357		11/1/2022		
	TGP	NET-NE (Z5-Z6)	95346	4,000		\$6.2957		11/30/2022		
	TGP	FT-A (Z5-Z6)	2302	3,122		\$6.2957		10/31/2025		
	TGP	FT-A (Z0-Z6)	8587	7,035		\$20.3736		10/31/2025		
	TGP	FT-A (Z1-Z6)	8587	14,561		\$18.0875		10/31/2025		
	TCPL + Union	FT to Parkway & PNGTS	M12284 & TC	5,000		\$20.6972		10/31/2040		
	PNGTS	FT	225800	5,000		\$22.8125		10/31/2040		
	TGP	FT-A (Z6-Z6)	42076	20,000		\$4.1818		10/31/2025		
	TGP	FT-A (Z6-Z6)	358905	40,000		\$4.1818		10/31/2041		
	TGP	FT-A (Z6-Z6)	72694	30,000		\$12.2113		10/31/2029		
	<b>Storage</b>	TGP	FS-MA (Storage)	523*	21,844	1,560,391	\$1.3094	\$0.0179	10/31/2025	
		TGP	FT-A (Z4-Z6)	632	15,265		\$7.1645		10/31/2025	
		TGP	FT-A (Z4-Z6)	8587	3,811		\$7.1645		10/31/2025	
National Fuel		FSS-1 (Storage)	O02357*	6,098	670,800	\$2.6325	\$0.0476	3/31/2023		
National Fuel		FST (Transport)	N02358	6,098		\$4.5274		3/31/2023		
TGP		FT-A (Z4-Z6)	11234	6,150		\$7.1645		10/31/2025		
Honeoye		SS-NY (Storage)	SS-NY**	1,957	245,380	\$4.2672	\$0.0000	3/31/2023	X	
TGP		FT-A (Z5-Z6)	11234	1,957		\$6.2957		10/31/2025		
Dominion		GSS (Storage)	300076*	934	102,700	\$1.8716	\$0.0145	3/31/2024		
TGP		FT-A (Z4-Z6)	11234	932		\$7.1645		10/31/2025		
<b>Peaking</b>	Energy North	LNG/Propane****		23,769	-	\$54.7200	\$0.0000		X	

\* All gas transferred for storage contracts will be based on LDC's monthly WACOG

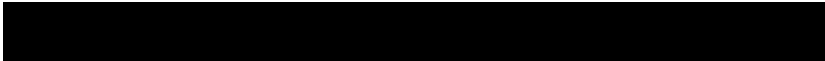
\*\*All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months

**Note:** All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/21. 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					
2					
3					
4 Subtotal					\$ 4,119,000.00 *
5					
6 Total					\$ 4,119,000.00

\* Contract currently being negotiated for an effective date of November 1, 2021

**SUBJECT TO CONFIDENTIAL TREATMENT**

**Calculation of Capacity Allocators  
Docket No DE 98-124**

**Capacity Assignment Table**

			% of Peak Day Requirement			
			Pipeline	Storage	Peaking	Total
<b>G-41</b>	<b>LAHW</b>	Low Annual C&I - High Winter Use	46.1%	17.1%	36.8%	100.0%
<b>G-51</b>	<b>LALW</b>	Low Annual C&I - Low Winter Use	59.3%	12.9%	27.9%	100.0%
<b>G-42</b>	<b>MAHW</b>	Medium C&I - High Winter Use	46.1%	17.1%	36.8%	100.0%
<b>G-52</b>	<b>MALW</b>	Medium C&I - Low Winter Use	59.3%	12.9%	27.9%	100.0%
<b>G-43</b>	<b>HAHW</b>	High Annual C&I - High Winter Use	46.1%	17.1%	36.8%	100.0%
<b>G-53</b>	<b>HALW90</b>	High Annual C&I - LF < 90%	59.3%	12.9%	27.9%	100.0%
<b>G-54</b>	<b>HALWG90</b>	High Annual C&I - LF > 90%	59.3%	12.9%	27.9%	100.0%

<b>HLF</b>	High Load Factor	59.25%	12.89%	27.85%	100%
<b>LLF</b>	Low Load Factor	46.09%	17.06%	36.85%	100%
	Total	47.29%	16.68%	36.03%	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

Allocate Class Design Day Throughput to Supply Sources

% of Peak Day Requirement

Design DD		71,544			Allocate Class Design Day Throughput to Supply Sources							% of Peak Day Requirement				
		Base load	Heat load	Total	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking	Total		
HLF	R-1 RNSH	102	457	558	R-1 RNSH	102	200	301	81	175.73	558	R-1 RNSH	54.0%	14.6%	31.5%	100.0%
LLF	R-3 RSH	3,545	69,811	73,356	R-3 RSH	3,545	30,525	34,070	12,431	26,856	73,356	R-3 RSH	46.4%	16.9%	36.6%	100.0%
LLF	G-41 SL	770	30,823	31,593	G-41 SL	770	13,477	14,247	5,488	11,857	31,593	G-41 SL	45.1%	17.4%	37.5%	100.0%
HLF	G-51 SH	739	1,812	2,551	G-51 SH	739	792	1,531	323	697	2,551	G-51 SH	60.0%	12.6%	27.3%	100.0%
LLF	G-42 ML	1,473	37,931	39,404	G-42 ML	1,473	16,585	18,058	6,754	14,592	39,404	G-42 ML	45.8%	17.1%	37.0%	100.0%
HLF	G-52 MH	1,781	3,820	5,601	G-52 MH	1,781	1,670	3,451	680	1,470	5,601	G-52 MH	61.6%	12.1%	26.2%	100.0%
LLF	G-43 LL	663	8,239	8,901	G-43 LL	663	3,602	4,265	1,467	3,169	8,901	G-43 LL	47.9%	16.5%	35.6%	100.0%
HLF	G-53 LLL90	1,146	2,222	3,368	G-53 LLL90	1,146	972	2,117	396	855	3,368	G-53 LLL90	62.9%	11.7%	25.4%	100.0%
HLF	G-54 LLL90	461	2,780	3,241	G-54 LLL90	461	1,216	1,676	495	1,070	3,241	G-54 LLL90	51.7%	15.3%	33.0%	100.0%
	<b>TOTAL</b>	<b>10,678</b>	<b>157,896</b>	<b>168,574</b>	<b>TOTAL</b>	<b>10,678</b>	<b>69,040</b>	<b>79,718</b>	<b>28,115</b>	<b>60,741</b>	<b>168,574</b>	<b>TOTAL</b>	<b>47.3%</b>	<b>16.7%</b>	<b>36.0%</b>	<b>100.0%</b>
<b>HLF</b>		<b>4,227</b>	<b>11,092</b>	<b>15,319</b>	<b>HLF</b>	<b>4,227</b>	<b>4,850</b>	<b>9,077</b>	<b>1,975</b>	<b>4,267</b>	<b>15,319</b>	<b>High Load Factor</b>	<b>59.25%</b>	<b>12.89%</b>	<b>27.85%</b>	<b>100%</b>
<b>LLF</b>		<b>6,450</b>	<b>146,804</b>	<b>153,255</b>	<b>LLF</b>	<b>6,450</b>	<b>64,190</b>	<b>70,641</b>	<b>26,140</b>	<b>56,474</b>	<b>153,255</b>	<b>Low Load Factor</b>	<b>46.09%</b>	<b>17.06%</b>	<b>36.85%</b>	<b>100%</b>
<b>Total</b>		<b>10,678</b>	<b>157,896</b>	<b>168,574</b>	<b>Total</b>	<b>10,678</b>	<b>69,040</b>	<b>79,718</b>	<b>28,115</b>	<b>60,741</b>	<b>168,574</b>	<b>Total</b>	<b>47.29%</b>	<b>16.68%</b>	<b>36.03%</b>	<b>100%</b>

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	71.544			
	Daily Baseload * 1000	Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	102	6.01	430	532
R-3 RSH	3,545	918.47	65,711	69,256
G-41 SL	770	405.52	29,013	29,783
G-51 SH	739	23.84	1,706	2,445
G-42 ML	1,473	499.04	35,703	37,176
G-52 MH	1,781	50.26	3,596	5,376
G-43 LL	663	108.39	7,755	8,418
G-53 LLL90	1,146	29.24	2,092	3,238
G-54 LLG90	461	36.58	2,617	3,078
<b>TOTAL</b>	<b>10,678</b>	<b>1,939.15</b>	<b>148,622</b>	<b>159,300</b>
HLF	4,227	146	10,440	14,668
LLF	6,450	1,793	138,182	144,632
<b>Total</b>	<b>10,678</b>	<b>1,939</b>	<b>148,622</b>	<b>159,300</b>
<b>Design Day from 2020-2021 COG</b>				<b>168,574</b>
<b>Design Day from Gas Load Calculation</b>				159,300
<b>Variance</b>				9,274

Allocate Design Day Sendout to  
Rate Classes

Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
19%	0.289%	102	457	558
5%	44.214%	3,545	69,811	73,356
3%	19.521%	770	30,823	31,593
30%	1.148%	739	1,812	2,551
4%	24.023%	1,473	37,931	39,404
33%	2.419%	1,781	3,820	5,601
8%	5.218%	663	8,239	8,901
35%	1.408%	1,146	2,222	3,368
15%	1.761%	461	2,780	3,241
	100.000%	10,678	157,896	168,574



Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators  
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CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total	Monthly Baseload	Daily Baseload
															(Jul+Aug)/2	
HLF	R-1 RNSH	7	9	9	8	8	6	5	4	3	3	4	5	70	3.149	0.102
LLF	R-3 RSH	731	957	994	889	717	509	274	143	111	110	142	327	5,904	109.892	3.545
LLF	G-41 SL	285	394	409	364	274	188	88	36	24	24	36	106	2,228	23.872	0.770
HLF	G-51 SH	36	43	43	40	34	30	30	25	23	25	25	29	383	22.908	0.739
LLF	G-42 ML	394	516	531	474	375	262	142	64	46	48	71	175	3,100	45.648	1.473
HLF	G-52 MH	91	103	106	98	79	71	67	56	55	58	60	73	917	55.198	1.781
LLF	G-43 LL	98	127	130	121	102	70	45	25	21	22	27	49	836	20.550	0.663
HLF	G-53 LLL90	50	56	61	59	53	44	46	39	38	40	36	48	571	35.515	1.146
HLF	G-54 LLL110	20	26	27	25	20	18	18	14	16	16	15	18	233	14.280	0.461
HLF	G-99 LLG110															
	<b>TOTAL</b>	1,713	2,229	2,311	2,080	1,662	1,198	714	406	337	346	416	829	14,242	341.449	11.014
<b>HLF</b>		204	235	246	231	194	168	166	138	136	142	140	173	2,174	131.050	4.480
<b>LLF</b>		1,509	1,994	2,064	1,849	1,468	1,030	549	268	201	204	276	656	12,067	199.962	6.534

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

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
		30	31	31	29	31	30	31	30	31	31	30	31	366
HLF	R-1 RNSH	3	3	3	3	3	3	3	3	3	3	3	3	37
LLF	R-3 RSH	106	110	110	103	110	106	110	106	111	110	106	110	1,297
LLF	G-41 SL	23	24	24	22	24	23	24	23	24	24	23	24	282
HLF	G-51 SH	22	23	23	21	23	22	23	22	23	25	22	23	270
LLF	G-42 ML	44	46	46	43	46	44	46	44	46	48	44	46	539
HLF	G-52 MH	53	55	55	52	55	53	55	53	55	58	53	55	652
LLF	G-43 LL	20	21	21	19	21	20	21	20	21	22	20	21	243
HLF	G-53 LLL90	34	36	36	33	36	34	36	34	38	40	34	36	419
HLF	G-54 LLL110	14	14	14	13	14	14	14	14	16	16	14	14	169
HLF	G-63 LLL110	0	0	0	0	0	0	0	0	0	0	0	0	0
	<b>TOTAL</b>	320	331	331	310	331	320	331	320	337	346	320	331	3,908
<b>HLF</b>		127	131	131	123	131	127	131	127	136	142	127	131	1,547
<b>LLF</b>		194	200	200	187	200	194	200	194	201	204	194	200	2,361

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

**Calculation of Capacity Allocators  
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**Heating Volumes (= Actual Volumes - Baseload)**

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
HLF	R-1 RNSH	4	5	6	5	5	3	2	1	0	0	0	2	32
LLF	R-3 RSH	625	848	884	786	607	403	164	37	0	0	35	217	4,607
LLF	G-41 SL	262	370	386	342	250	165	64	13	0	0	13	82	1,946
HLF	G-51 SH	14	20	20	19	11	8	7	2	0	0	3	6	112
LLF	G-42 ML	350	470	485	432	329	218	97	20	0	0	27	129	2,561
HLF	G-52 MH	38	48	50	46	24	17	12	3	0	0	7	18	265
LLF	G-43 LL	78	106	110	102	81	50	24	5	0	0	7	29	593
HLF	G-53 LLL90	15	20	26	26	18	10	11	5	0	0	1	13	152
HLF	G-54 LLL110	6	11	13	12	6	4	4	0	0	0	2	3	65
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	<b>TOTAL</b>	1,393	1,898	1,980	1,771	1,331	878	383	86	0	0	95	498	10,333

<b>HLF</b>	78	104	115	109	63	42	35	11	0	0	13	42	627
<b>LLF</b>	1,315	1,794	1,864	1,662	1,268	836	349	74	0	0	82	456	9,707

<b>Actual BDD</b>	<b>846.0</b>	<b>1054.0</b>	<b>1025.0</b>	<b>963.0</b>	<b>724.0</b>	<b>491.0</b>	<b>257.0</b>	<b>31.0</b>	<b>0.0</b>	<b>4.0</b>	<b>87.0</b>	<b>341.0</b>	<b>5823.0</b>
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**Heat Factors**

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total	AVG	AVG Peak
HLF	R-1 RNSH	0.0046	0.0051	0.0056	0.0054	0.0063	0.0061	0.0072	0.0237	0.0000	0.0000	0.0052	0.0047	0.0063	0.0062	0.0055
LLF	R-3 RSH	0.7389	0.8042	0.8621	0.8165	0.8388	0.8206	0.6374	1.1853	0.0000	0.0000	0.4063	0.6357	0.8621	0.6455	0.8135
LLF	G-41 SL	0.3101	0.3511	0.3762	0.3553	0.3448	0.3361	0.2481	0.4058	0.0000	0.0000	0.1467	0.2396	0.3762	0.2595	0.3456
HLF	G-51 SH	0.0168	0.0186	0.0200	0.0197	0.0154	0.0154	0.0258	0.0799	0.0000	0.0000	0.0350	0.0178	0.0200	0.0220	0.0177
LLF	G-42 ML	0.4137	0.4462	0.4733	0.4481	0.4550	0.4445	0.3764	0.6498	0.0000	0.0000	0.3128	0.3797	0.4733	0.3666	0.4468
HLF	G-52 MH	0.0448	0.0453	0.0492	0.0481	0.0335	0.0353	0.0449	0.0868	0.0000	0.0000	0.0776	0.0526	0.0492	0.0432	0.0427
LLF	G-43 LL	0.0921	0.1006	0.1073	0.1059	0.1123	0.1019	0.0951	0.1524	0.0000	0.0000	0.0805	0.0837	0.1123	0.0860	0.1034
HLF	G-53 LLL90	0.0180	0.0191	0.0253	0.0271	0.0242	0.0201	0.0427	0.1650	0.0000	0.0000	0.0132	0.0372	0.0271	0.0326	0.0223
HLF	G-54 LLL110	0.0074	0.0107	0.0122	0.0126	0.0082	0.0079	0.0139	0.0149	0.0000	0.0000	0.0183	0.0098	0.0126	0.0097	0.0098
HLF	G-63 LLG110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	<b>TOTAL</b>	1.6465	1.8008	1.9312	1.8387	1.8386	1.7879	1.4914	2.7635	0.0000	0.0000	1.0957	1.4609	1.9391	1.4713	1.8073

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators  
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Actual HDD	846.0	1,054.0	1,025.0	963.0	724.0	491.0	257.0	31.0	0.0	4.0	87.0	341.0	5823.0
Norm HDD	715.2	1,044.9	1,216.8	1,071.2	893.6	508.8	226.5	49.9	5.0	8.2	108.0	407.2	6255.0

Normal Volumes (= Heating Volumes \* Normal HDD/Actual HDD + Baseload)

	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
HLF R-1 RNSH	6	8	10	9	9	6	5	4	3	3	4	5	72
LLF R-3 RSH	635	950	1,159	977	859	524	254	165	111	110	150	369	6,264
LLF G-41 SL	245	391	482	403	332	194	80	43	24	24	39	121	2,378
HLF G-51 SH	34	42	47	43	37	30	29	26	23	25	26	30	392
LLF G-42 ML	340	512	622	523	452	270	131	77	46	48	78	200	3,298
HLF G-52 MH	85	103	115	103	85	71	65	58	55	58	62	77	937
LLF G-43 LL	86	126	151	133	121	72	42	27	21	22	29	55	883
HLF G-53 LLL90	47	55	66	62	57	45	45	43	38	40	36	51	585
HLF G-54 LLL110	19	25	29	27	22	18	17	15	16	16	16	18	238
HLF G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	1,498	2,213	2,681	2,279	1,974	1,230	669	458	337	346	439	926	15,049

HLF	192	234	268	244	209	170	161	145	136	142	143	181	2,225
LLF	1,306	1,978	2,413	2,036	1,765	1,060	507	313	201	204	296	745	12,823

**Liberty Utilities (EnergyNorth Natural Gas) Corp.  
Peak 2021 - 2022 Winter Cost of Gas Filing  
Fixed Price Option**

	Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential	Residential	Residential	Difference	% Difference	FPO Rate	C&I	C&I	C&I	Difference	% Difference
						Average	Total Bill	Total Bill				Average	Total Bill	Total Bill		
						COG Rate	FPO Rate	COG Rate				COG Rate	FPO Rate	COG Rate		
1 Nov 98 - Mar 99	6.0%				0.3927	0.3722	943.3700	926.9333	\$ 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	679.8500	672.2235	\$ 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	816.2500	916.0900	\$ (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	790.6522	760.5504	\$ 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	\$ 128,045.78	0.5553	0.5758	821.3224	840.4371	\$ (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	\$ 552,330.59	0.8597	0.8220	1,115.5548	1,080.4628	\$ 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	\$ 273,781.28	0.8925	0.9425	1,142.9556	1,189.5541	\$ (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	\$ 518,881.82	1.2951	1.1342	1,526.0076	1,376.0122	\$ 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	\$ 262,713.68	1.2664	1.1656	1,509.7908	1,415.8032	\$ 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	\$ 281,571.06	1.2043	1.1746	1,433.0900	1,405.4000	\$ 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	\$ 260,826.70	1.2835	1.0888	1,555.3140	1,373.8536	\$ 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	\$ 168,108.26	0.9863	0.9416	1,250.8032	1,209.1161	\$ 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	\$ 207,596.08	0.8420	0.8029	1,175.0264	1,138.5767	\$ 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	\$ 156,703.94	0.8126	0.7309	1,165.8100	1,089.4400	\$ 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	\$ 163,590.48	0.6919	0.7680	743.0298	792.4756	\$ (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	\$ 178,615.58	0.9095	1.0980	857.7200	981.2100	\$ (123.49)	-12.59%	0.9108	1.1058	\$ 2,899.04	\$ 3,280.18	\$ (381.14)	-11.62%
17 Nov 14 - Apr 15	15.1%	0.0795	8,779,742	\$ 697,989.49	1.2425	0.5100	1,127.6600	948.0700	\$ 179.59	18.94%	0.5143	1.1341	\$ 2,135.42	\$ 2,340.00	\$ (204.58)	-8.74%
18 Nov 15 - Apr 16	15.3%	0.0200	4,941,157	\$ 98,823.14	0.7716	0.7516	869.1500	712.7315	\$ 156.42	21.95%						
19 Nov 16 - Apr 17	11.5%	0.0106	5,419,967	\$ 57,451.65	0.7268	0.7162	827.1400	812.3754	\$ 14.76	1.82%						
20 Nov 17 - Apr 18	10.6%	0.0200	5,298,900	\$ 105,978.00	0.6645	0.6445	878.7000	865.9400	\$ 12.76	1.47%						
21 Nov 18 - Apr 19	10.8%	0.0200	5,708,925	\$ 114,178.50	0.7611	0.7411	984.8300	972.1200	\$ 12.71	1.31%						
22 Nov 19 - Apr 20	7.2%	0.0200	3,447,167	\$ 68,943.34	0.6403	0.6203	930.4600	917.7400	\$ 12.72	1.39%						
23 Nov 20 - Apr 21	11.1%	0.0200	5,373,268	\$ 107,465.36	0.5771	0.5571	895.3200	882.6000	\$ 12.72	1.44%						
24 Total					0.9256	0.9056	1,200.9474	1,187.6074	\$ -	0.00%						
									\$ 734.45						\$ 273.86	

**Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
Peak 2021 - 2022 Winter Cost of Gas Filing  
Short-Term Debt Limitations**

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	<b><u>For Purposes of Fuel Financing</u></b>	
Total Direct Gas Costs	\$	94,810,891
Total Indirect Gas Costs		<u>4,338,002</u>
Total Gas Costs	\$	99,148,894
% of Debt to Total Gas Costs		30%
Short Term Debt	\$	29,744,668

	<b><u>For Purposes Other Than Fuel Financing</u></b>	
<b>12/31/2022 Projected Net Plant</b>	\$	577,357,182
% of Debt to Net Plant		20%
Short Term Debt	\$	115,471,436

**Liberty Utilities (EnergyNorth Natural Gas) Corp.  
d/b/a Liberty  
2021 - 2022 Winter Cost of Gas Filing**

**Company Allowance Calculation**

	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Jan-2021	Feb-2021	Mar-2021	Apr-2021	May-2021	Jun-2021	Total
Total Sendout- Therms	4,938,887	5,112,192	5,945,559	10,622,623	16,152,030	24,369,322	27,682,105	25,333,064	19,358,615	12,846,303	8,102,604	5,396,076	165,859,380
Total Throughput- Therms	4,935,276	5,092,677	5,227,989	6,532,773	11,027,584	18,555,165	24,820,512	26,998,121	25,544,486	17,127,373	10,787,513	7,181,623	163,831,092
Variance	3,611	19,515	717,570	4,089,850	5,124,446	5,814,157	2,861,593	(1,665,057)	(6,185,871)	(4,281,070)	(2,684,909)	(1,785,547)	2,028,288
Company Allowance													<b>1.22%</b>

**Lost and Unaccounted For Gas ("LAUF") Calculation**

	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Jan-2021	Feb-2021	Mar-2021	Apr-2021	May-2021	Jun-2021	Total
Total Sendout- Therms	4,938,887	5,112,192	5,945,559	10,622,623	16,152,030	24,369,322	27,682,105	25,333,064	19,358,615	12,846,303	8,102,604	5,396,076	165,859,380
Total Throughput- Therms	4,935,276	5,092,677	5,227,989	6,532,773	11,027,584	18,555,165	24,820,512	26,998,121	25,544,486	17,127,373	10,787,513	7,181,623	163,831,092
Company Use	3,851	3,369	4,202	7,264	17,411	30,017	40,656	56,444	38,332	18,882	10,038	5,937	236,403
Variance	(240)	16,146	713,368	4,082,586	5,107,035	5,784,140	2,820,937	(1,721,501)	(6,224,203)	(4,299,952)	(2,694,947)	(1,791,484)	1,791,885
LAUF													<b>1.08%</b>

**Liberty Utilities (EnergyNorth Natural Gas) Corp.**  
**d/b/a Liberty**  
**Fuel Inventory Revenue Requirement**

Updated Schedule 26  
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		<b>5 Quarter Avg</b>	<b>Q2 2020</b>	<b>Q3 2020</b>	<b>Q4 2020</b>	<b>Q1 2021</b>	<b>Q2 2021</b>
2	Gas Stored Underground	\$ 1,861,932	\$ 1,684,887	\$ 2,749,506	\$ 2,331,076	\$ 456,008	\$ 2,088,182
3	Fuel Stock - Propane	\$ 1,103,820	\$ 1,182,985	\$ 1,306,812	\$ 1,314,267	\$ 879,390	\$ 835,646
4	UG Storage - LNG	<u>\$ 50,349</u>	\$ 48,351	\$ 54,291	\$ 52,792	\$ 51,959	\$ 44,351
5		\$ 3,016,100					
6	ROR		<u>8.76%</u>	Pre-Tax Rate of 6.64% and Statutory Tax Rate of 27.08%			
		\$ 264,132					
7	Income Tax Gross-up		1.2708				
8	Revenue Requirement	<u>\$ 335,667</u>					

**II RATE SCHEDULES**  
**FIRM RATE SCHEDULES**

Rates effective November 1, 2021 - April 30, 2022  
Rates effective November 1, 2021 - April 30, 2021

Rates Effective May 1, 2022 - October 31, 2022  
Rates Effective May 1, 2021 - October 31, 2021

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 95	LDAC Page 101	Total Rate	Delivery Charge	Cost of Gas Rate Page 92	LDAC Page 101	Total Rate
<b>Residential Non Heating - R-1</b>	\$ 15.50			\$ 15.50	\$ 15.50			\$ 15.50
Customer Charge per Month per Meter	\$ 15.39			\$ 15.39	\$ 15.39			\$ 15.39
All Therms	\$ 0.3844	\$ 1.1339	\$ 0.1444	\$ 1.6627	\$ 0.3844	\$ 0.5587	\$ 0.1444	\$ 1.0875
	\$ 0.3860	\$ 0.5574	\$ 0.0589	\$ 1.0020	\$ 0.3860	\$ 0.4944	\$ 0.0589	\$ 0.9363
<b>Residential Heating - R-3</b>	\$ 15.50			\$ 15.50	\$ 15.50			\$ 15.50
Customer Charge per Month per Meter	\$ 15.39			\$ 15.39	\$ 15.39			\$ 15.39
Size of the first block								
all therms								
Therms in the first block per month at	\$ 0.5632	\$ 1.1339	\$ 0.1444	\$ 1.8415	\$ 0.5632	\$ 0.5587	\$ 0.1444	\$ 1.2663
	\$ 0.5678	\$ 0.5574	\$ 0.0589	\$ 1.1838	\$ 0.5678	\$ 0.4944	\$ 0.0589	\$ 1.1181
<b>Residential Heating - R-4</b>	\$ 8.52			\$ 8.52	\$ 15.50			\$ 15.50
Customer Charge per Month per Meter	\$ 8.47			\$ 8.47	\$ 15.39			\$ 15.39
Size of the first block								
all therms								
20 therms	\$ 0.3098	\$ 0.6236	\$ 0.1444	\$ 1.0778	\$ 0.5632	\$ 0.5587	\$ 0.1444	\$ 1.2663
Therms in the first block per month at	\$ 0.3123	\$ 0.3064	\$ 0.0589	\$ 0.6776	\$ 0.5678	\$ 0.4944	\$ 0.0589	\$ 1.1181
	\$ 57.46			\$ 57.46	\$ 57.46			\$ 57.46
<b>Commercial/Industrial - G-41</b>	\$ 57.06			\$ 57.06	\$ 57.06			\$ 57.06
Customer Charge per Month per Meter	\$ 57.06			\$ 57.06	\$ 57.06			\$ 57.06
Size of the first block								
100 therms								
20 therms								
Therms in the first block per month at	\$ 0.4688	\$ 1.1341	\$ 0.0878	\$ 1.6907	\$ 0.4688	\$ 0.5593	\$ 0.0878	\$ 1.1159
	\$ 0.4711	\$ 0.5552	\$ 0.0555	\$ 1.0818	\$ 0.4711	\$ 0.4868	\$ 0.0555	\$ 1.0134
All therms over the first block per month at	\$ 0.3149	\$ 1.1341	\$ 0.0878	\$ 1.5368	\$ 0.3149	\$ 0.5593	\$ 0.0878	\$ 0.9620
	\$ 0.3165	\$ 0.5552	\$ 0.0555	\$ 0.9272	\$ 0.3165	\$ 0.4868	\$ 0.0555	\$ 0.8588
<b>Commercial/Industrial - G-42</b>	\$ 172.39			\$ 172.39	\$ 172.39			\$ 172.39
Customer Charge per Month per Meter	\$ 171.19			\$ 171.19	\$ 171.19			\$ 171.19
Size of the first block								
1000 therms								
400 therms								
Therms in the first block per month at	\$ 0.4261	\$ 1.1341	\$ 0.0878	\$ 1.6480	\$ 0.4261	\$ 0.5593	\$ 0.0878	\$ 1.0732
	\$ 0.4284	\$ 0.5552	\$ 0.0555	\$ 1.0391	\$ 0.4284	\$ 0.4868	\$ 0.0555	\$ 0.9707
All therms over the first block per month at	\$ 0.2839	\$ 1.1341	\$ 0.0878	\$ 1.5058	\$ 0.2839	\$ 0.5593	\$ 0.0878	\$ 0.9310
	\$ 0.2855	\$ 0.5552	\$ 0.0555	\$ 0.8962	\$ 0.2855	\$ 0.4868	\$ 0.0555	\$ 0.8278
<b>Commercial/Industrial - G-43</b>	\$ 739.83			\$ 739.83	\$ 739.83			\$ 739.83
Customer Charge per Month per Meter	\$ 734.69			\$ 734.69	\$ 734.69			\$ 734.69
All therms over the first block per month at	\$ 0.2620	\$ 1.1341	\$ 0.0878	\$ 1.4839	\$ 0.1198	\$ 0.5593	\$ 0.0878	\$ 0.7669
	\$ 0.2633	\$ 0.5552	\$ 0.0555	\$ 0.8740	\$ 0.1204	\$ 0.4868	\$ 0.0555	\$ 0.6627
<b>Commercial/Industrial - G-51</b>	\$ 57.46			\$ 57.46	\$ 57.46			\$ 57.46
Customer Charge per Month per Meter	\$ 57.06			\$ 57.06	\$ 57.06			\$ 57.06
Size of the first block								
100 therms								
100 therms								
Therms in the first block per month at	\$ 0.2819	\$ 1.1324	\$ 0.0878	\$ 1.5021	\$ 0.2819	\$ 0.5580	\$ 0.0878	\$ 0.9277
	\$ 0.2839	\$ 0.5660	\$ 0.0555	\$ 0.9054	\$ 0.2839	\$ 0.4985	\$ 0.0555	\$ 0.8379
All therms over the first block per month at	\$ 0.1833	\$ 1.1324	\$ 0.0878	\$ 1.4035	\$ 0.1833	\$ 0.5580	\$ 0.0878	\$ 0.8291
	\$ 0.1846	\$ 0.5660	\$ 0.0555	\$ 0.8061	\$ 0.1846	\$ 0.4985	\$ 0.0555	\$ 0.7368
<b>Commercial/Industrial - G-52</b>	\$ 172.39			\$ 172.39	\$ 172.39			\$ 172.39
Customer Charge per Month per Meter	\$ 171.19			\$ 171.19	\$ 171.19			\$ 171.19
Size of the first block								
1000 therms								
1000 therms								
Therms in the first block per month at	\$ 0.2428	\$ 1.1324	\$ 0.0878	\$ 1.4630	\$ 0.1759	\$ 0.5580	\$ 0.0878	\$ 0.8217
	\$ 0.2439	\$ 0.5660	\$ 0.0555	\$ 0.8654	\$ 0.1767	\$ 0.4985	\$ 0.0555	\$ 0.7307
All therms over the first block per month at	\$ 0.1617	\$ 1.1324	\$ 0.0878	\$ 1.3819	\$ 0.1000	\$ 0.5580	\$ 0.0878	\$ 0.7458
	\$ 0.1624	\$ 0.5660	\$ 0.0555	\$ 0.7839	\$ 0.1004	\$ 0.4985	\$ 0.0555	\$ 0.6544
<b>Commercial/Industrial - G-53</b>	\$ 761.39			\$ 761.39	\$ 761.39			\$ 761.39
Customer Charge per Month per Meter	\$ 756.10			\$ 756.10	\$ 756.10			\$ 756.10
All therms over the first block per month at	\$ 0.1697	\$ 1.1324	\$ 0.0878	\$ 1.3899	\$ 0.0814	\$ 0.5580	\$ 0.0878	\$ 0.7272
	\$ 0.1705	\$ 0.5660	\$ 0.0555	\$ 0.7920	\$ 0.0818	\$ 0.4985	\$ 0.0555	\$ 0.6358
<b>Commercial/Industrial - G-54</b>	\$ 761.39			\$ 761.39	\$ 761.39			\$ 761.39
Customer Charge per Month per Meter	\$ 756.10			\$ 756.10	\$ 756.10			\$ 756.10
All therms over the first block per month at	\$ 0.0648	\$ 1.1324	\$ 0.0878	\$ 1.2850	\$ 0.0352	\$ 0.5580	\$ 0.0878	\$ 0.6810
	\$ 0.0650	\$ 1.1324	\$ 0.0878	\$ 1.2852	\$ 0.0353	\$ 0.4985	\$ 0.0555	\$ 0.5893

Issued: October xx, 2020      October xx, 2021  
Effective: November 1, 2020      November 1, 2021

Issued by: \_\_\_\_\_  
Neil Proudman  
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.  
Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141.



Rates effective November 1, 2021 - April 30, 2022  
~~Rates effective November 1, 2021 - April 30, 2021~~  
Winter Period

Rates Effective May 1, 2022 - October 31, 2022  
~~Rates Effective May 1, 2021 - October 31, 2021~~  
Summer Period

	Delivery Charge	Cost of Gas Rate Page 92	LDAC Charge	Total Rate	Delivery Charge	Cost of Gas Rate Page 89	LDAC Page 97	Total Rate
<b>Residential Non Heating - R-5</b>	\$ 20.15			\$ 20.15	\$ 20.15			\$ 20.15
Customer Charge per Month per Meter	\$ 20.01			\$ 20.01	\$ 20.01			\$ 20.01
All therms	\$ 0.4997	\$ 1.1339	\$ 0.1444	\$ 1.7780	\$ 0.4997	\$ 0.5587	\$ 0.1444	\$ 1.2028
	\$ 0.5018	\$ 0.5571	\$ 0.0589	\$ 1.1178	\$ 0.5018	\$ 0.3148	\$ 0.0589	\$ 0.8755
<b>Residential Heating - R-6</b>	\$ 20.15			\$ 20.15	\$ 20.15			\$ 20.15
Customer Charge per Month per Meter	\$ 20.01			\$ 20.01	\$ 20.01			\$ 20.01
All therms	\$ 0.7322	\$ 1.1339	\$ 0.1444	\$ 2.0105	\$ 0.7322	\$ 0.5587	\$ 0.1444	\$ 1.4353
	\$ 0.7381	\$ 0.5571	\$ 0.0589	\$ 1.3541	\$ 0.7381	\$ 0.3148	\$ 0.0589	\$ 1.1148
<b>Residential Heating - R-7</b>	\$ 11.08			\$ 11.08	\$ 20.15			\$ 20.15
Customer Charge per Month per Meter	\$ 11.01			\$ 11.01	\$ 11.01			\$ 11.01
All therms	\$ 0.4027	\$ 0.6236	\$ 0.1444	\$ 1.1707	\$ 0.4027	\$ 0.5587	\$ 0.1444	\$ 1.1058
	\$ 0.4060	\$ 0.3064	\$ 0.0589	\$ 0.7713	\$ 0.7381	\$ 0.3148	\$ 0.0589	\$ 1.1148
<b>Commercial/Industrial - G-44</b>	\$ 74.69			\$ 74.69	\$ 74.69			\$ 74.69
Customer Charge per Month per Meter	\$ 74.18			\$ 74.18	\$ 74.18			\$ 74.18
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	\$ 0.6094	\$ 1.1341	\$ 0.0878	\$ 1.8313	\$ 0.5539	\$ 0.5593	\$ 0.0878	\$ 1.2010
	\$ 0.6126	\$ 0.5552	\$ 0.0555	\$ 1.2233	\$ 0.6126	\$ 0.3109	\$ 0.0555	\$ 0.9790
All therms over the first block per month a	\$ 0.4094	\$ 1.1341	\$ 0.0878	\$ 1.6313	\$ 0.3691	\$ 0.5593	\$ 0.0878	\$ 1.0162
	\$ 0.4114	\$ 0.5552	\$ 0.0555	\$ 1.0224	\$ 0.4114	\$ 0.3109	\$ 0.0555	\$ 0.7778
<b>Commercial/Industrial - G-45</b>	\$ 224.44			\$ 224.44	\$ 224.44			\$ 224.44
Customer Charge per Month per Meter	\$ 222.55			\$ 222.55	\$ 222.55			\$ 222.55
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	\$ 0.5539	\$ 1.1341	\$ 0.0878	\$ 1.7758	\$ 0.5539	\$ 0.5593	\$ 0.0878	\$ 1.2010
	\$ 0.5569	\$ 0.5552	\$ 0.0555	\$ 1.1676	\$ 0.5569	\$ 0.3109	\$ 0.0555	\$ 0.9233
All therms over the first block per month a	\$ 0.3691	\$ 1.1341	\$ 0.0878	\$ 1.5910	\$ 0.3691	\$ 0.5593	\$ 0.0878	\$ 1.0162
	\$ 0.3711	\$ 0.5552	\$ 0.0555	\$ 0.9818	\$ 0.3711	\$ 0.3109	\$ 0.0555	\$ 0.7375
<b>Commercial/Industrial - G-46</b>	\$ 961.78			\$ 961.78	\$ 961.78			\$ 961.78
Customer Charge per Month per Meter	\$ 955.10			\$ 955.10	\$ 955.10			\$ 955.10
All therms over the first block per month a	\$ 0.3406	\$ 1.1341	\$ 0.0878	\$ 1.5625	\$ 0.1557	\$ 0.5593	\$ 0.0878	\$ 0.8028
	\$ 0.3423	\$ 0.5552	\$ 0.0555	\$ 0.9530	\$ 0.1566	\$ 0.3109	\$ 0.0555	\$ 0.5229
<b>Commercial/Industrial - G-55</b>	\$ 74.69			\$ 74.69	\$ 74.69			\$ 74.69
Customer Charge per Month per Meter	\$ 74.18			\$ 74.18	\$ 74.18			\$ 74.18
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	\$ 0.3665	\$ 1.1324	\$ 0.0878	\$ 1.5867	\$ 0.3665	\$ 0.5580	\$ 0.0878	\$ 1.0123
	\$ 0.3691	\$ 0.5660	\$ 0.0555	\$ 0.9906	\$ 0.3691	\$ 0.3199	\$ 0.0555	\$ 0.7445
All therms over the first block per month a	\$ 0.2383	\$ 1.1324	\$ 0.0878	\$ 1.4585	\$ 0.2383	\$ 0.5580	\$ 0.0878	\$ 0.8841
	\$ 0.2400	\$ 0.5660	\$ 0.0555	\$ 0.8615	\$ 0.2400	\$ 0.3199	\$ 0.0555	\$ 0.6154
<b>Commercial/Industrial - G-56</b>	\$ 224.44			\$ 224.44	\$ 224.44			\$ 224.44
Customer Charge per Month per Meter	\$ 222.55			\$ 222.55	\$ 222.55			\$ 222.55
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	\$ 0.3157	\$ 1.1324	\$ 0.0878	\$ 1.5359	\$ 0.2287	\$ 0.5580	\$ 0.0878	\$ 0.8745
	\$ 0.3171	\$ 0.5660	\$ 0.0555	\$ 0.9386	\$ 0.2297	\$ 0.3199	\$ 0.0555	\$ 0.6054
All therms over the first block per month a	\$ 0.2102	\$ 1.1324	\$ 0.0878	\$ 1.4304	\$ 0.1300	\$ 0.5580	\$ 0.0878	\$ 0.7758
	\$ 0.2111	\$ 0.5660	\$ 0.0555	\$ 0.8326	\$ 0.1304	\$ 0.3199	\$ 0.0555	\$ 0.5117
<b>Commercial/Industrial - G-57</b>	\$ 989.80			\$ 989.80	\$ 989.80			\$ 989.80
Customer Charge per Month per Meter	\$ 982.93			\$ 982.93	\$ 982.93			\$ 982.93
All therms over the first block per month a	\$ 0.2207	\$ 1.1324	\$ 0.0878	\$ 1.4409	\$ 0.1059	\$ 0.5580	\$ 0.0878	\$ 0.7517
	\$ 0.2216	\$ 0.5660	\$ 0.0555	\$ 0.8434	\$ 0.1063	\$ 0.3199	\$ 0.0555	\$ 0.4817
<b>Commercial/Industrial - G-58</b>	\$ 989.80			\$ 989.80	\$ 989.80			\$ 989.80
Customer Charge per Month per Meter	\$ 982.93			\$ 982.93	\$ 970.84			\$ 970.84
All therms over the first block per month a	\$ 0.0842	\$ 1.1324	\$ 0.0878	\$ 1.3044	\$ 0.0457	\$ 0.5580	\$ 0.0878	\$ 0.6915
	\$ 0.0846	\$ 0.5660	\$ 0.0555	\$ 0.7061	\$ 0.0459	\$ 0.3199	\$ 0.0555	\$ 0.4213

Issued: ~~October xx, 2020~~  
Effective: ~~November 1, 2020~~

October xx, 2021  
November 1, 2021

Issued by: \_\_\_\_\_  
Title: Neil Proudman  
President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.  
Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141

Anticipated Cost of Gas  
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2022 THROUGH OCTOBER 31, 2022  
~~PERIOD COVERED: SUMMER PERIOD, MAY 1, 2021 THROUGH OCTOBER 31, 2021~~  
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)
<b>ANTICIPATED DIRECT COST OF GAS</b>				
<b>Purchased Gas:</b>				
Demand Costs:	\$ 2,919,324		\$ 3,276,842	
Supply Costs:	<u>2,202,634</u>		6,971,475	
<b>Storage Gas:</b>				
Demand, Capacity:	_____		-	
Commodity Costs:	_____		-	
<b>Produced Gas:</b>	<u>22,682</u>		82,504	
<b>Hedged Contract Savings</b>	_____		-	
	_____		_____	
<b>Unadjusted Anticipated Cost of Gas</b>		\$ 5,144,637		\$ 10,330,821
<b>Adjustments:</b>				
Prior Period (Over)/Under Recovery as of <del>April 30, 2018</del> September 01, 2019 (monthly adjustment filing)	\$ 1,885,446		\$ 4,472,186	
Interest	<u>51,144</u>		222,837	
Prior Period Adjustments	_____		-	
Broker Revenues	_____		-	
Refunds from Suppliers	_____		-	
Fuel Financing	-		-	
Transportation CGA Revenues	_____		-	
Interruptible Sales Margin	_____		-	
Capacity Release and Off System Sales Margin	_____		-	
Hedging Costs	_____		-	
Fixed Price Option Administrative Costs	_____		-	
<b>Total Adjustments</b>	<u>1,936,590</u>		<u>4,695,023</u>	
<b>Total Anticipated Direct Cost of Gas</b>		\$ 7,081,227		\$ 15,025,844
<b>Anticipated Indirect Cost of Gas</b>				
<b>Working Capital:</b>				
Total anticipated Direct Cost of Gas <del>(05/01/2018 - 10/31/2018)</del> (05/01/19 - 10/31/19)	\$ 5,144,637		\$ 10,330,821	
Working Capital Rate	0.0391		-	
Prime Rate	3.25%		3.25%	
Working Capital Percentage	<u>0.127%</u>		<u>0.01%</u>	
Working Capital	6,538		769	
Plus: Working Capital Reconciliation <del>(Acct 142-20)</del> (Acct 1163-1424)	<u>(18,982)</u>		4,555	
Total Working Capital Allowance		\$ (12,443)		\$ 5,324
<b>Bad Debt:</b>				
Total anticipated Direct Cost of Gas <del>(05/01/2018 - 10/31/2018)</del> (05/01/19 - 10/31/19)	\$ 5,144,637		\$ 10,330,821	
Less: Refunds	-		-	
Plus: Total Working Capital	<u>(12,443)</u>		5,324	
Plus: Prior Period (Over)/Under Recovery	<u>1,885,446</u>		4,472,186	
Subtotal	<u>\$ 7,017,640</u>		<u>\$ 14,808,331</u>	
Bad Debt Percentage	4.11%		0.70%	
Bad Debt Allowance	<u>77,896</u>		103,658	
Plus: Bad Debt Reconciliation <del>(Acct 175-52)</del> (Acct 1163-1754)	<u>(280,167)</u>		23,159	
Total Bad Debt Allowance		<u>(202,272)</u>		126,817
<b>Production and Storage Capacity</b>				
Miscellaneous Overhead <del>(05/01/2018 - 10/31/2018)</del> (05/01/19 - 10/31/19)	\$ 13,170		-	
Times Summer <del>Winter</del> Sales	<u>20,973</u>		23,366	
Divided by Total Sales	<u>109,299</u>		115,043	
Miscellaneous Overhead	<u>2,527</u>		-	
Total Anticipated Indirect Cost of Gas		<u>\$ (212,188)</u>		\$ 132,141
<b>Total Cost of Gas</b>		<u>\$ 6,869,039</u>		<u>\$ 15,157,985</u>

Issued: ~~October xx, 2020~~ October xx, 2021  
Effective: ~~November 4, 2020~~ November 1, 2021

Issued by: \_\_\_\_\_  
Neil Proudman  
President  
Title:

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.  
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

CALCULATION OF FIRM SALES COST OF GAS RATE  
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2022 THROUGH OCTOBER 31, 2022  
~~PERIOD COVERED: SUMMER PERIOD, MAY 1, 2021 THROUGH OCTOBER 31, 2021~~  
(Refer to Text in Section 17 Cost of Gas Clause)

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)
Total Anticipated Direct Cost of Gas	\$ 0,653,380		\$ 15,025,844	
Projected Prorated Sales (05/01/22 - 10/31/22) <del>(05/01/21 - 10/31/21)</del>	<u>20,973,034</u>		27,125,444	
<b>Direct Cost of Gas Rate</b>		\$ 0.4603		\$ 0.5539 per therm
<b>Demand Cost of Gas Rate</b>	\$ 4,548,346	\$ 0.2169	\$ 3,276,842	\$ 0.1208
<b>Commodity Cost of Gas Rate</b>	<u>3,136,847</u>	<u>0.1496</u>	<u>7,053,979</u>	<u>0.2601</u>
<b>Adjustment Cost of Gas Rate</b>	<u>1,968,188</u>	<u>0.0938</u>	<u>4,695,023</u>	<u>0.1731</u>
<b>Total Direct Cost of Gas Rate</b>	\$ 9,653,380	\$ 0.4603	\$ 15,025,844	\$ 0.5539
Total Anticipated Indirect Cost of Gas	\$ (174,652)		\$ 131,366	
Projected Prorated Sales (05/01/22 - 10/31/22) <del>(05/01/21 - 10/31/21)</del>	<u>20,973,034</u>		27,125,444	
<b>Indirect Cost of Gas</b>		\$ (0.0083)		\$ 0.0048 per therm
<b>TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22</b>				\$ 0.5587 per Therm
<b>TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21</b>		\$ 0.4520		
<b>RESIDENTIAL COST OF GAS RATE - 05/01/2022</b>			<b>COGsr</b>	<b>\$ 0.5587 /therm</b>
<b>RESIDENTIAL COST OF GAS RATE - 5/01/21</b>			<b>COGsr</b>	<b>\$ 0.4520 /therm</b>
		Maximum (COG + 25%)	\$ 0.6984	\$ 0.6984
<b>COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2022</b>			<b>COGsl</b>	<b>\$ 0.5580 /therm</b>
<b>COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2021</b>			<b>COGsl</b>	<b>\$ 0.4591 /therm</b>
Average Demand Cost of Gas Rate Effective 05/01/21 05/01/2022	\$ 0.2169	\$ 0.1208	Maximum (COG + 25%)	\$ 0.6739 \$ 0.6975
Times: Low Winter Use Ratio (Summer)	1.0465	0.9910		
Times: Correction Factor	0.9867	1.0027		
Adjusted Demand Cost of Gas Rate	\$ 0.2240	\$ 0.1200		
Commodity Cost of Gas Rate	\$ 0.1496	\$ 0.2601		
Adjustment Cost of Gas Rate	0.0938	0.1731		
Indirect Cost of Gas Rate	(0.0083)	0.0048		
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	\$ 0.4591	\$ 0.5580		
<b>COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2021</b>			<b>COGsh</b>	<b>\$ 0.5593 /therm</b>
<b>COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2020</b>			<b>COGsh</b>	<b>\$ 0.4474 /therm</b>
Average Demand Cost of Gas Rate Effective 05/01/20 05/01/2021	\$ 0.2169	\$ 0.1208	Maximum (COG + 25%)	\$ 0.5593 \$ 0.6991
Times: High Winter Use Ratio (Summer)	0.9948	1.0017		
Times: Correction Factor	0.9867	1.0027		
Adjusted Demand Cost of Gas Rate	\$ 0.2123	\$ 0.1213		
Commodity Cost of Gas Rate	\$ 0.1496	\$ 0.2601	Minimum	
Adjustment Cost of Gas Rate	0.0938	0.1731	Maximum	
Indirect Cost of Gas Rate	(0.0083)	0.0048		
Adjusted Com/Ind High Winter Use Cost of Gas Rate	\$ 0.4474	\$ 0.5593		

Issued: ~~October xx, 2020~~ October xx, 2021  
Effective: ~~November 1, 2020~~ November 1, 2021

Issued by: \_\_\_\_\_  
Neil Proudman  
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.  
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141.~~

**Liberty Utilities (EnergyNorth Natural Gas) Corp.****Off Peak 2022 Summer Cost of Gas Filing****Table of Contents**

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3	Schedule 3	COG (Over)/Under Cumulative Recovery Balances and Interest Calculation
4	Schedule 4	Adjustments to Gas Costs
5	Schedule 5A Schedule 5B Schedule 5C	Demand Costs Demand Volumes Demand Rates
6	Schedule 6 Attachment	Supply and Commodity Costs, Volumes and Rates Pipeline Tariff Sheets
7	Schedule 7	NYMEX Futures @ Henry Hub and Hedged Contracts
8	Schedule 8, Page 1 Schedule 8, Page 2 Schedule 8, Page 3 Schedule 8, Page 4 Schedule 8, Page 5	Annual Bill Comparisons, May 20 - Oct 20 vs May 21 - Oct 21 - Residential Heating Rate R-3 Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-41 Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-42 Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-52 Residential Heating
9	Schedule 9	This schedule is no longer relevant
10	Schedule 10A Pages 1-2 Schedule 10A Page 3 Schedule 10B	Capacity Assignment Calculations 2020-2021 Derivation of Class Assignments and Weightings Correction Factor Calculation Off Peak 2022 Summer Cost of Gas Filing
11	Schedule 11A Schedule 11B Schedule 11C	Normal and Design Year Volumes Normal Year Normal and Design Year Volumes Design Year Capacity Utilization
12	Schedule 12, Page 1 Schedule 12, Page 2	Transportation Available for Pipeline Supply and Storage Agreements for Gas Supply and Transportation
13	Schedule 13	Storage Inventory

3 Off Peak 2022 Summer Cost of Gas Filing

4 Summary

5			OP 22
6		Reference	May - Oct
7	(a)	(b)	(c)
9	<b>Anticipated Direct Cost of Gas</b>		
10	Purchased Gas:		
11	Demand Costs:	Sch. 5A, col (j), ln 46	\$ 3,276,842
12	Supply Costs	Sch. 6, col (i), ln 45	6,971,475
13			
14	Storage Gas:		
15	Demand, Capacity:	Sch. 5A, col (j), ln 61	\$ -
16	Commodity Costs:	Sch. 6, col (i), ln 48	-
17			
18	Produced Gas:	Sch. 6, col (i), ln 54	\$ 82,504
19			
20	Hedge Contract (Savings)/Loss		\$ -
21			
22			
23	<b>Total Unadjusted Cost of Gas</b>		<u>\$ 10,330,821</u>
24			
25	<b>Adjustments:</b>		
26			
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	\$ 4,472,186
28	Interest 11/01/19 - 10/31/20	Sch. 3, col (q) ln 193	222,837
29	Prior Period Adjustments	Sch. 4, ln 24 col (b)	-
30	Refunds from Suppliers	Sch. 4, ln 24 col (c)	-
31	Broker Revenue	Sch. 4, ln 24 col (d)	-
32	Fuel Financing	Sch. 4, ln 24 col (e)	-
33	Transportation CGA Revenues	Sch. 4, ln 24 col (f)	-
34	Interruptible Sales Margin	Sch. 4, ln 24 col (g)	-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 24 col (h) + col (i)	-
36	Hedging Costs	Sch. 4, ln 24 col (j)	-
37	FPO Premium - Collection		-
38	Fixed Price Option Administrative Costs	Sch. 4, ln 24 col (k)	-
39			
40	<b>Total Adjustments</b>		<u>\$ 4,695,023</u>
41			
42	<b>Total Anticipated Direct Costs</b>	ln 23 + 40	<u>\$ 15,025,844</u>
43			
44	<b>Anticipated Indirect Cost of Gas</b>		
45	<b>Working Capital</b>		
46	Total Unadjusted Anticipated Cost of Gas	ln 23	\$ 10,330,821
47	Lead Lag Days / 365	DG 10-017, 14.27 / 365	0.0000
48	Prime Rate		3.25%
49	Working Capital Percentage	ln 47 * ln 48	0.000%
50	Working Capital	ln 46 * ln 49	-
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 98	4,555
52			
53	<b>Total Working Capital Allowance</b>	ln 50 + 51	<u>\$ 4,555</u>
54			
55	<b>Bad Debt</b>		
56	Total Unadjusted Anticipated Cost of Gas	ln 23	\$ 10,330,821
57	Less Refunds	ln 30	-
58	Plus Working Capital	ln 53	4,555
59	Plus Prior Period (Over) Under Recovery	ln 27	4,472,186
60	Subtotal		<u>\$ 14,807,562</u>
61	Bad Debt Percentage	per GTC 17(f)	0.70%
62			
63	Bad Debt Allowance	ln 60 * ln 61	\$ 103,653
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 163	23,159
65			
66	<b>Total Bad Debt Allowance</b>	ln 63 + 64	<u>\$ 126,812</u>
67			
68	<b>Production and Storage Capacity</b>	per GTC17(f)	<u>\$ -</u>
69			
70	<b>Miscellaneous Overhead</b>	per GTC 17(f)	\$ -
71	Sales Volume	Sch. 10B, ln 23/1000	23,366
72	Divided by Total Sales	Sch. 10B, ln 23/1000	115,043
73	Ratio		<u>20.31%</u>
74			
75	<b>Miscellaneous Overhead</b>	ln 70 * 73	<u>\$ -</u>
76			
77	<b>Total Anticipated Indirect Cost of Gas</b>	ln 53 + 66 + 68 + 75	<u>\$ 131,366</u>
78			
79	<b>Total Cost of Gas</b>	ln 42 + 77	<u>\$ 15,157,210</u>
80			
81	<b>Projected Forecast Sales (Therms)</b>	Sch. 3, col (q), ln 52	<u>27,125,444</u>

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

2

3 Off Peak 2022 Summer Cost of Gas Filing

4 Summary of Supply and Demand Forecast

Updated Schedule 1

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5

6

7 For Month of:

8 (a)

(b)

May-22

Jun-22

Jul-22

Aug-22

Sep-22

Oct-22

Nov-22

Off Peak Period

May - Oct

9 I. Gas Volumes (Therms)

10

11 A. Firm Demand Volumes

12 Firm Gas Sales Sch. 10B, In 23 870,536 2,672,893 2,207,233 2,239,093 3,355,253 7,222,123 8,558,316 27,125,444

13 Lost Gas (Unaccounted for) 53,988 29,666 24,501 25,149 36,419 78,230 247,952

14 Company Use 3,081 1,693 1,398 1,435 2,079 4,465 14,152

15 Unbilled Therms 4,069,607 41,684 34,671 62,109 (22,767) (63,717) (8,558,316) (4,436,728)

16

17 Total Firm Volumes Sch. 6, In 93 4,997,212 2,745,936 2,267,802 2,327,785 3,370,983 7,241,101 22,950,820

18

19 B. Supply Volumes (Therms)

20 Pipeline Gas:

21 Dawn Supply Sch. 6, In 63 739,535 95,658 - - 206,295 636,518 1,678,006

22 Niagara Supply Sch. 6, In 64 668,413 540,809 542,484 545,801 591,423 687,667 3,576,596

23 TGP Supply (Gulf) Sch. 6, In 65 13,120 - - - - 384,326 397,446

24 Dracut Supply 1 - Baseload Sch. 6, In 66 - - - - - - -

25 Dracut Supply 2 - Swing Sch. 6, In 67 - - - - - 436,185 436,185

26 City Gate Delivered Supply Sch. 6, In 68 - - - - - - -

27 LNG Truck Sch. 6, In 69 44,883 18,131 - - 55,566 20,602 139,181

28 Propane Truck Sch. 6, In 70 79,409 71,899 69,472 69,279 73,449 81,696 445,204

29 PNGTS Sch. 6, In 71 205,081 146,300 119,612 125,908 176,916 218,093 991,910

30 Portland Natural Gas Sch. 6, In 72 152,602 3,126 - - 2,555 574,003 732,286

31 TGP Supply (Zone 4) Sch. 6, In 73 5,386,659 4,708,479 4,708,982 4,696,535 4,819,522 5,546,088 29,866,267

32 Subtotal Pipeline Volumes 7,289,702 5,584,403 5,440,551 5,437,523 5,925,726 8,585,177 38,263,081

33

34 Storage Gas:

35 TGP Storage Sch. 6, In 78 - - - - - - -

36

37 Produced Gas:

38 LNG Vapor Sch. 6, In 81 20,024.76 18,131.18 17,518.99 17,470.44 18,521.89 20,601.58 112,268.82

39 Propane Sch. 6, In 82 - - - - - - -

40 Subtotal Produced Gas 20,024.76 18,131.18 17,518.99 17,470.44 18,521.89 20,601.58 112,268.82

41

42 Less - Gas Refill:

43 LNG Truck Sch. 6, In 87 (44,883.07) (18,131.18) - - (55,565.66) (20,601.58) (139,181.49)

44 Propane Sch. 6, In 88 (79,408.52) (71,899.50) (69,471.84) (69,279.32) (73,448.86) (81,695.93) (445,203.96)

45 TGP Storage Refill Sch. 6, In 89 (2,188,222.48) (2,766,567.68) (3,120,795.80) (3,057,928.82) (2,444,250.24) (1,262,379.73) (14,840,144.76)

46 Subtotal Refills (2,312,514.07) (2,856,598.36) (3,190,267.64) (3,127,208.14) (2,573,264.76) (1,364,677.25) (15,424,530.21)

47

48 Total Firm Sendout Volumes Ins 32 + 35 + 40 + 46 4,997,212.39 2,745,935.65 2,267,802.45 2,327,785.06 3,370,983.22 7,241,101.08 22,950,819.85

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

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3 Off Peak 2022 Summer Cost of Gas Filing

4 Summary of Supply and Demand Forecast

49

50 II. Gas Costs

51

52 A. Demand Costs

53 Supply

54 Niagara Supply Sch.5A, In 12  
 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, In 16  
 61 Tenn Gas Pipeline 95346 Z5-Z6 Sch.5A, In 17  
 62 Tenn Gas Pipeline 2302 Z5-Z6 Sch.5A, In 18  
 63 Tenn Gas Pipeline 8587 Z0-Z6 Sch.5A, In 19  
 64 Tenn Gas Pipeline 8587 Z1-Z6 Sch.5A, In 20  
 65 Tenn Gas Pipeline 8587 Z4-Z6 Sch.5A, In 21  
 66 Tenn Gas Pipeline (Dracut) 42076 Z6-Z6 Sch.5A, In 22  
 67 Tenn Gas Pipeline (Dracut) 358905 Z6-Z7 Sch.5A, In 23  
 68 Tenn Gas Pipeline (Concord Lateral) Z6-Z6 Sch.5A, In 24  
 69 Portland Natural Gas Trans Service Sch.5A, In 25  
 70 ANE (TransCanada via Union to Iroquois) Sch.5A, In 27  
 71 Portland Natural Gas Sch.5A, In 25  
 72 TransCanada via Union to Portland Sch.5A, In 27  
 73 Tenn Gas Pipeline Z4-Z6 stg 632 Sch.5A, In 29  
 74 Tenn Gas Pipeline Z4-Z6 stg 11234 Sch.5A, In 30  
 75 Tenn Gas Pipeline Z5-Z6 stg 11234 Sch.5A, In 31  
 76 National Fuel FST 2358 Sch.5A, In 32

77 Subtotal Pipeline Demand	\$ 823,110	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 3,703,482	\$ 4,954,402
78 Less Capacity Credit	(278,705)	(279,771)	(279,771)	(279,771)	(279,771)	(279,771)	(1,253,999)	(1,677,561)
79 Net Pipeline Demand Costs	\$ 544,405	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 2,449,483	\$ 3,276,842

80

81 Peaking Supply:

82 Tenn Gas Pipeline (Concord Lateral) Z6-Z6 Sch.5A, In 37  
 83 Granite Ridge Demand Sch.5A, In 38  
 84 DOMAC Demand NSB041 Sch.5A, In 39  
 85 Subtotal Peaking Demand  
 86 Less Capacity Credit  
 87 Net Peaking Supply Demand Costs

88

89 Storage:

90 Dominion - Demand Sch.5A, In 49  
 91 Dominion - Storage Sch.5A, In 50  
 92 Honeoye - Demand Sch.5A, In 51  
 93 National Fuel - Demand Sch.5A, In 52  
 94 National Fuel - Capacity Sch.5A, In 53  
 95 Tenn Gas Pipeline - Demand Sch.5A, In 54  
 96 Tenn Gas Pipeline - Capacity Sch.5A, In 55  
 97 Subtotal Storage Demand  
 98 Less Capacity Credit  
 99 Net Storage Demand Costs

97 Subtotal Storage Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
98 Less Capacity Credit	-	-	-	-	-	-	-	-
99 Net Storage Demand Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

101 Total Demand Charges	Ins 55 + 77 + 85 + 97	\$ 823,110	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 3,703,482	\$ 4,954,402
102 Total Capacity Credit	Ins 56 + 78 + 86 + 98	(278,705)	(279,771)	(279,771)	(279,771)	(279,771)	(1,253,999)	(1,677,561)
103 Net Demand Charges		\$ 544,405	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 2,449,483	\$ 3,276,842

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 Updated Schedule 1  
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1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
2  
3 Off Peak 2022 Summer Cost of Gas Filing  
4 Summary of Supply and Demand Forecast

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105									
106									
107	<b>B. Commodity Costs</b>								
108	<u>Pipeline:</u>								
109	Dawn Supply	Sch. 6, In 12							
110	Niagara Supply	Sch. 6, In 13							
111	TGP Supply (Gulf)	Sch. 6, In 14							
112	Dracut Supply 1 - Baseload	Sch. 6, In 15							
113	Dracut Supply 2 - Swing	Sch. 6, In 16							
114	Dracut Supply 3 - Swing	Sch. 6, In							
115	City Gate Delivered Supply	Sch. 6, In 17							
116	LNG Truck	Sch. 6, In 18							
117	Portland Natural Gas	Sch. 6, In 21							
118	PNGTS	Sch. 6, In 20							
119	TGP Supply (Zone 4)	Sch. 6, In 22							
120	Subtotal Pipeline Commodity Costs		\$ 2,582,425	\$ 1,948,176	\$ 1,951,410	\$ 1,908,418	\$ 1,867,983	\$ 2,854,727	\$ 13,113,139
121									
122	<u>Storage:</u>								
123	TGP Storage - Withdrawals	Sch. 6, In 48	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
124									
125	<u>Produced Gas Costs:</u>								
126	LNG Vapor	Sch. 6, In 51							
127	Propane	Sch. 6, In 52							
128	Subtotal Produced Gas Costs		\$ 13,993	\$ 13,159	\$ 12,913	\$ 12,877	\$ 13,652	\$ 15,911	\$ 82,504
129									
130	<u>Less Storage Refills:</u>								
131	LNG Truck	Sch. 6, In 38							
132	Propane	Sch. 6, In 39							
133	TGP Storage Refill	Sch. 6, In 40							
134	Storage Refill (Trans.)	Sch. 6, In 41							
135	Subtotal Storage Refill		\$ (960,246)	\$ (1,223,872)	\$ (1,393,945)	\$ (1,367,756)	\$ (1,088,979)	\$ (566,192)	\$ (6,600,989)
136									
137	Total Supply Commodity Costs		\$ 1,636,172	\$ 737,463	\$ 570,378	\$ 553,539	\$ 792,656	\$ 2,304,446	\$ 6,594,655
138									
139	<b>C. Supply Volumetric Transportation Costs:</b>								
140	Dawn Supply	Sch. 6, In 27							
141	Niagara Supply	Sch. 6, In 28							
142	TGP Supply (Zone 4)	Sch. 6, In 29							
143	Dracut Supply 1 - Baseload	Sch. 6, In 30							
144	Dracut Supply 2 - Swing	Sch. 6, In 31							
145	Dracut Supply 3 - Swing	Sch. 6, In							
146	Subtotal Pipeline Volumetric Trans. Costs		\$ 88,990	\$ 71,093	\$ 70,660	\$ 70,003	\$ 71,501	\$ 87,078	\$ 459,325
147									
148	TGP Storage - Withdrawals	Sch. 6, In 33	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
149									
150	Total Supply Volumetric Trans. Costs	Ins 146 + 148	\$ 88,990	\$ 71,093	\$ 70,660	\$ 70,003	\$ 71,501	\$ 87,078	\$ 459,325
151									
152	Total Commodity Gas & Trans. Costs	Ins 137 + 150	\$ 1,725,162	\$ 808,556	\$ 641,038	\$ 623,542	\$ 864,157	\$ 2,391,524	\$ 7,053,979

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

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3 Off Peak 2022 Summer Cost of Gas Filing

4 Summary of Supply and Demand Forecast

157 D. Supply and Demand Costs by Source

158

159

160 Purchased Gas Demand Costs

161	Pipeline Gas Demand Costs	Ins 55 + 77	\$ 823,110	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 4,954,402
162	Peaking Gas Demand Costs	In 85	-	-	-	-	-	-	-
163	Subtotal Purchased Gas Demand Costs		\$ 823,110	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 826,258	\$ 4,954,402
164	Less Capacity Credit	Ins 56 + 78 + 86	(278,705)	(279,771)	(279,771)	(279,771)	(279,771)	(279,771)	(1,677,561)
165	Net Purchased Gas Demand Costs		\$ 544,405	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 3,276,842

166

167 Storage Gas Demand Costs

168	Storage Demand	In 97	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
169	Less Capacity Credit	In 98	-	-	-	-	-	-	-
170	Net Storage Demand Costs		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

171

172	<b>Total Demand Costs</b>	Ins 165 + 170	\$ 544,405	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 3,276,842
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173

174 Purchased Gas Supply

175	Commodity Costs	In 120	[REDACTED]						\$ 6,971,475
176	Less Storage Inj. (TGP Storage)	In 133							
177	Less Storage Transportation	In 134							
178	Less LNG Truck	In 131							
179	Less Propane Truck	In 132							
180	Plus Transportation Costs	In 146							
181	Subtotal Purchased Gas Supply		\$ 1,711,170	\$ 795,397	\$ 628,125	\$ 610,666	\$ 850,505	\$ 2,375,613	\$ 6,971,475

182

183 Storage Commodity Costs

184	Commodity Costs	In 123	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
185	Transportation Costs	In 148	-	-	-	-	-	-	-
186	Subtotal Storage Commodity Costs		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

187

188 Produced Gas Commodity Costs

188	Produced Gas Commodity Costs	In 128	\$ 13,993	\$ 13,159	\$ 12,913	\$ 12,877	\$ 13,652	\$ 15,911	\$ 82,504
189	<b>Subtotal Commodity Costs</b>	Ins 181 + 186 + 188	\$ 1,725,162	\$ 808,556	\$ 641,038	\$ 623,542	\$ 864,157	\$ 2,391,524	\$ 7,053,979

191

192 Hedge Contract (Savings)/Loss

192	Hedge Contract (Savings)/Loss		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
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193

194	<b>Total Commodity Costs</b>	Ins 190 + 192	\$ 1,725,162	\$ 808,556	\$ 641,038	\$ 623,542	\$ 864,157	\$ 2,391,524	\$ 7,053,979
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195

196	<b>Total Demand Costs</b>	In 103	\$ 544,405	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 546,487	\$ 3,276,842
197	<b>Total Supply Costs</b>	In 194	1,725,162	808,556	641,038	623,542	864,157	2,391,524	7,053,979

198

199	<b>Total Direct Gas Costs</b>	Ins 196 + 197	\$ 2,269,567	\$ 1,355,043	\$ 1,187,525	\$ 1,170,030	\$ 1,410,644	\$ 2,938,011	\$ 10,330,821
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1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

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Updated Schedule 2

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3 Off Peak 2022 Summer Cost of Gas Filing

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4 Contracts Ranked on a per Unit Cost Basis

Off Peak

5

6	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Cost per Unit Dth
7	(a)	(b)	(c)	(d)	(e)	(f)

8

9 Demand Costs

10

11

12	ANE (TransCanada via Union to Iroquois)	Dawn - Parkway to Iroquois	Transportation	MDQ	4,047	
13	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
14	Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
15	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
16	Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
17	Dominion - Demand	GSS 300076	Storage	MDQ	934	
18	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
19	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
20	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	40,000	
21	National Fuel	FST N02358	Transportation	MDQ	6,098	
22	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
23	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
24	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
25	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
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 (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
29	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
30	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
31	TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	5,077	
32	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
33	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
34	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
35	Portland Natural Gas	FTN	Transportation	MDQ	5,000	

36

37 Supply Costs - Commodity

38	LNG Truck		Pipeline	Dkt	13,918	
39	TGP Supply (Zone 4)		Pipeline	Dkt	2,986,627	
40	Niagara Supply		Pipeline	Dkt	357,660	
41	Dracut Supply 2 - Swing		Pipeline	Dkt	43,619	
42	Dawn Supply		Pipeline	Dkt	167,801	
43	TGP Citygate Supply		Pipeline	Dkt	-	
44	PNGTS		Pipeline	Dkt	99,191	
45	Dracut Supply 1 - Baseload		Pipeline	Dkt	-	
46	TGP Supply (Gulf)		Pipeline	Dkt	39,745	
47	LNG Vapor		Produced	Dkt	11,227	
48	Propane		Pipeline	Dkt	-	

49

50 Supply Costs - Volumetric Transportation

51	Dracut Supply 1 - Baseload		Pipeline	Dkt	-	
52	TGP Supply (Zone 4)		Pipeline	Dkt	39,745	
53	Dracut Supply 2 - Swing		Pipeline	Dkt	43,619	
54	Dawn Supply		Storage	Dkt	167,801	
55	Niagara Supply		Pipeline	Dkt	357,660	

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57

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

3 Off Peak 2022 Summer Cost of Gas Filing  
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

Updated Schedule 3  
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	Days in Month	Prior Period Balance Plus Nov Collections October 31, 2021	Nov-21 30	Dec-21 31	Jan-22 31	Feb-22 28	Mar-22 31	Apr-22 30	May-22 31	Jun-22 30	Jul-22 31	Aug-22 31	Sep-22 30	Oct-22 31	Nov-22 30	Off Peak Period Total	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	
<b>Account 8840-2-0000-10-1920-1741 (formerly, 175.40) COG (Over)/Under Balance - Interest Calculation</b>																	
13	Beginning Balance	Account 1920-1741 1/	\$ 4,472,186	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,589,886	\$ 4,172,732	\$ 4,108,398	\$ 4,146,596	\$ 4,133,544	\$ 3,771,672	\$ 2,753,139	\$ 4,472,186
14	Forecast Direct Gas Costs		-	-	-	-	-	-	-	2,380,201	1,465,677	1,298,159	1,280,664	1,521,278	3,048,645	-	10,994,623
15	Production & Storage & Misc Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Projected Revenues w/o Int.	In 54 * In 64	-	-	-	-	-	-	-	(496,376)	(1,524,072)	(1,258,554)	(1,276,721)	(1,913,150)	(4,118,023)	(4,879,914)	(15,466,809)
17	Projected Unbilled Revenue	In 58 * In 64	-	-	-	-	-	-	-	(2,320,472)	(2,344,240)	(2,364,010)	(2,399,424)	(2,386,442)	(2,350,111)	-	(14,164,699)
18	Reverse Prior Month Unbilled		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Add Net Adjustments (with TGP Refund)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Gas Cost Billed	Account 1920-1741 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Monthly (Over)/Under Recovery		\$ 4,472,186	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,153,239	\$ 4,090,569	\$ 4,128,233	\$ 4,115,124	\$ 3,754,653	\$ 2,738,625	\$ 223,336	\$ 0
22	Average Monthly Balance	(In 13 + 21)/ 2	\$ -	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,371,563	\$ 4,131,650	\$ 4,118,315	\$ 4,130,860	\$ 3,944,098	\$ 3,255,148	\$ 1,488,238	
24	Interest Rate	Prime Rate		5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%		
26	Interest Applied	In 22 * In 24 /365 *Days/Mo.	\$ -	\$ 19,298	\$ 20,027	\$ 20,116	\$ 18,251	\$ 20,287	\$ 19,721	\$ 19,492	\$ 17,828	\$ 18,363	\$ 18,419	\$ 17,019	\$ 14,514	\$ -	\$ 223,336
28	<b>(Over)/Under Balance</b>	In 21 + In 26	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,589,886	\$ 4,172,732	\$ 4,108,398	\$ 4,146,596	\$ 4,133,544	\$ 3,771,672	\$ 2,753,139	\$ 223,336	\$ 223,336
<b>Calculation of COG with Interest</b>																	
33	Beginning Balance	In 13	\$ 4,472,186	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,589,886	\$ 4,137,119	\$ 4,053,078	\$ 4,074,889	\$ 4,044,949	\$ 3,658,681	\$ 2,588,011	\$ 4,472,186
34	Forecast Direct Gas Costs	In 14	-	-	-	-	-	-	-	2,380,201	1,465,677	1,298,159	1,280,664	1,521,278	3,048,645	-	10,994,623
35	Prod Storage & Misc Overhead	In 15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Projected Revenues with Int.	In 54 * 66	-	-	-	-	-	-	-	(502,645)	(1,543,321)	(1,274,450)	(1,292,846)	(1,937,313)	(4,170,033)	(4,941,547)	(15,662,155)
37	Projected Unbilled Revenue	In 58 * 66	-	-	-	-	-	-	-	(2,349,780)	(2,373,848)	(2,393,867)	(2,429,728)	(2,416,583)	(2,379,793)	-	(14,343,599)
38	Reverse Prior Month Unbilled		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Add Net Adjustments	In 19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Gas Cost Billed	In 20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Gas Cost Unbilled		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Reverse Prior Month Unbilled		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Add Interest	In 26	-	-	-	-	-	-	-	19,492	17,828	18,363	18,419	17,019	14,514	-	105,636
44	<b>(Over)/Under Balance</b>		\$ 4,472,186	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,137,155	\$ 4,053,236	\$ 4,075,131	\$ 4,045,265	\$ 3,659,078	\$ 2,588,597	\$ 26,256	\$ (89,710)
46	Average Monthly Balance		\$ -	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,363,520	\$ 4,095,177	\$ 4,064,105	\$ 4,060,077	\$ 3,852,014	\$ 3,123,639		
48	Interest Applied	In 24 * In 46 /365 *Days/Mo.	\$ -	\$ 19,298	\$ 20,027	\$ 20,116	\$ 18,251	\$ 20,287	\$ 19,721	\$ 19,457	\$ 17,671	\$ 18,121	\$ 18,103	\$ 16,622	\$ 13,928	\$ -	\$ 221,602
50	<b>(Over)/Under Balance</b>	In 43 +In 44 + In 48	\$ 4,472,186	\$ 4,491,484	\$ 4,511,511	\$ 4,531,627	\$ 4,549,878	\$ 4,570,165	\$ 4,589,886	\$ 4,137,119	\$ 4,053,078	\$ 4,074,889	\$ 4,044,949	\$ 3,658,681	\$ 2,588,011	\$ 26,256	\$ 26,256
53	Forecast Sendout Therms	Sch 1								4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101		22,950,820
54	Less Forecast Billing Therm Sales	Sch. 10B, In 23 May - Oct								870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316	27,125,444
55	Less Forecast Unaccounted For	Sch 1								53,988	29,666	24,501	25,149	36,419	78,230		247,952
56	Less Forecast Company Use	Sch 1								3,081	1,693	1,398	1,435	2,079	4,465		14,152
57	Unbilled Volumes									4,069,607	41,684	34,671	62,109	(22,767)	(63,717)	(8,558,316)	(4,436,728)
58	Gross Unbilled									4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	(4,436,728)	
60	Beg Balance									-	4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	
61	Incremental									4,069,607	41,684	34,671	62,109	(22,767)	(63,717)	(8,558,316)	
62	Ending Balance									4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	(4,436,728)	
64	COG w/o Interest	Sch. 3, pg. 4, In 211 col. (c)								\$ 0.5702	\$ 0.5702	\$ 0.5702	\$ 0.5702	\$ 0.5702	\$ 0.5702	\$ 0.5702	
66	COG With Interest	Sch. 3, pg. 4, In 211 col. (d)								\$ 0.5774	\$ 0.5774	\$ 0.5774	\$ 0.5774	\$ 0.5774	\$ 0.5774	\$ 0.5774	

1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
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	Days in Month	Prior Period Balance Plus Nov Collections October 31, 2021 (c)	Nov-21 30 (d)	Dec-21 31 (e)	Jan-22 31 (f)	Feb-22 28 (g)	Mar-22 31 (h)	Apr-22 30 (i)	May-22 31 (j)	Jun-22 30 (k)	Jul-22 31 (l)	Aug-22 31 (m)	Sep-22 30 (n)	Oct-22 31 (o)	Nov-22 30 (p)	Off Peak Period Total (q)	
<b>76 Account 8840-2-0000-10-1163-1424 (formerly, 142.40) Working Capital (Over)/Under Balance - Interest Calculation</b>																	
78	<b>Beginning Balance</b>	Account 1163-1424 1/	\$ 4,555	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 4,675	\$ 3,864	\$ 3,424	\$ 3,062	\$ 2,688	\$ 2,139	\$ 944	\$ 4,555
79																	
80	Days Lag									0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
81	Prime Rate									3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
82	Forecast Working Capital	In 34 * In 80 / 365 * In 81								-	-	-	-	-	-	-	
83																	
84	Projected Revenues w/o Int.	In 123 * In 126								(146)	(449)	(371)	(376)	(563)	(1,213)	(1,437)	(4,555)
85	Projected Unbilled Revenue	In 124 * In 126								(683)	(690)	(696)	(707)	(703)	(692)	(692)	(4,171)
86	Reverse Prior Month Unbilled										683	690	696	707	703	692	4,171
87																	
88	Add Net Adjustments									-	-	-	-	-	-	-	
89																	
90	Working Capital Billed	Account 1163-1424 2/															
91																	
92	Monthly (Over)/Under Recovery		\$ 4,555	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 3,845	\$ 3,408	\$ 3,048	\$ 2,676	\$ 2,129	\$ 937	\$ 199	\$ -
93																	
94	Average Monthly Balance	(In 78 + 92) / 2	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 4,260	\$ 3,636	\$ 3,236	\$ 2,869	\$ 2,409	\$ 1,538			
95																	
96	Interest Rate	Prime Rate	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%		
97																	
98	Interest Applied	In 94 * In 96 / 365 * Days of Month	\$ 20	\$ 20	\$ 20	\$ 19	\$ 21	\$ 20	\$ 19	\$ 16	\$ 14	\$ 13	\$ 10	\$ 7		\$ 199	
99																	
100	<b>(Over)/Under Balance</b>	In 92 + In 98	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 3,864	\$ 3,424	\$ 3,062	\$ 2,688	\$ 2,139	\$ 944	\$ 199	\$ 199	
101																	
102																	
103	<b>Calculation of Working Capital with Interest</b>																
104																	
105	<b>Beginning Balance</b>		\$ 4,555	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 4,675	\$ 3,829	\$ 3,370	\$ 2,992	\$ 2,602	\$ 2,029	\$ 782	\$ 4,555
106	Forecast Working Capital	In 82															
107	Projected Rev. with Interest	In 123 * In 128								(152)	(468)	(386)	(392)	(587)	(1,264)	(1,497)	(4,746)
108	Projected Unbilled Revenue	In 124 * In 128								(712)	(719)	(725)	(736)	(732)	(721)	(721)	(4,346)
109	Reverse Prior Month Unbilled										712	719	725	736	732	721	4,346
110	Add Net Adjustments	In 88															
111	Working Capital Billed	In 90															
112	WC Unbilled																
113	Reverse WC Unbilled																
114	Add Interest	In 98								19	16	14	13	10	7		79
115	Monthly (Over)/Under Recovery		\$ 4,555	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 3,829	\$ 3,370	\$ 2,992	\$ 2,602	\$ 2,029	\$ 783	\$ 6	\$ (112)
116																	
117	Average Monthly Balance		\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 4,252	\$ 3,600	\$ 3,181	\$ 2,797	\$ 2,315	\$ 1,406			
118																	
119	Interest Applied	In 96 * In 117 / 365 * Days of Month	20	20	20	19	21	20	19	16	14	12	10	6		\$ 197	
120																	
121	<b>(Over)/Under Balance</b>	-In 114 + In 115 + In 119	\$ 4,555	\$ 4,574	\$ 4,595	\$ 4,615	\$ 4,634	\$ 4,654	\$ 3,829	\$ 3,370	\$ 2,992	\$ 2,602	\$ 2,029	\$ 782	\$ 6	\$ 6	
122																	
123	Forecast Therm Sales	In 53							870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316		27,125,444
124	Unbilled Therm	In 55							4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	(4,436,728)		
125																	
126	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, In 228 col. (c)							\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	
127																	
128	Working Capital Rate w/ Int.	Sch. 3, pg. 4, In 228 col. (d)							\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	
129																	

1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
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	Days in Month	Prior Period Balance Plus Nov Collections October 31, 2021	Nov-21 30	Dec-21 31	Jan-22 31	Feb-22 28	Mar-22 31	Apr-22 30	May-22 31	Jun-22 30	Jul-22 31	Aug-22 31	Sep-22 30	Oct-22 31	Nov-22 30	Off Peak Period Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
<b>Account 8840-2-0000-10-1163-1754 (formerly, 175.54) Bad Debt (Over)/Under Balance - Interest Calculation</b>																
139	Forecast Direct Gas Costs	In 34 In 106 + (May includes prior period )	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,380,201	\$ 1,465,677	\$ 1,298,159	\$ 1,280,664	\$ 1,521,278	\$ 3,048,645	\$ -	10,994,623
140	Forecast Working Capital	In 21 / 6	-	-	-	-	-	-	4,555	-	-	-	-	-	-	4,555
141	Prior Period Balance (with Refund)	In 21 / 6	-	-	-	-	-	-	745,364	745,364	745,364	745,364	745,364	745,364	-	4,472,186
142	Total Forecast Direct Gas Costs & Working Capital		-	-	-	-	-	-	3,130,120	2,211,041	2,043,523	2,026,028	2,266,642	3,794,009	-	10,999,178
144	<b>Beginning Balance</b>	Account 1163-1754 1/ Oct Collections & Unbilled	\$ 23,159	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 23,768	\$ 21,839	\$ 24,161	\$ 27,716	\$ 30,876	\$ 30,725	\$ 22,710	\$ 23,159
146	Forecast Bad Debt	In 142 * 0.007	-	-	-	-	-	-	21,911	15,477	14,305	14,182	15,866	26,558	-	108,300
148	Projected Revenues w/o int	In 184 * In 187	-	-	-	-	-	-	(4,219)	(12,954)	(10,697)	(10,851)	(16,261)	(35,001)	(41,476)	(131,458)
149	Projected Unbilled Revenue	In 185 * In 187	-	-	-	-	-	-	(19,723)	(19,925)	(20,093)	(20,394)	(20,283)	(20,283)	(19,974)	(120,391)
150	Reverse Prior Month Unbilled		-	-	-	-	-	-	-	19,723	19,925	20,093	20,394	20,283	19,974	120,391
152	Bad Debt Billed	Account 1163-1754 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Add Net Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-
155	Monthly (Over)/Under Recovery		\$ 23,159	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 21,738	\$ 24,161	\$ 27,600	\$ 30,746	\$ 30,592	\$ 22,591	\$ 1,208	\$ -
157	Average Monthly Balance	(In 144 + 155) / 2	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 23,666	\$ 22,753	\$ 23,000	\$ 25,881	\$ 29,231	\$ 30,734	\$ 26,658	\$ 11,959	
159	Interest Rate	Prime Rate	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%		
161	Interest Applied	In 157 * In 159 / 365 * Days of Mo.	\$ 100	\$ 104	\$ 104	\$ 95	\$ 105	\$ 102	\$ 101	\$ 99	\$ 115	\$ 130	\$ 133	\$ 119		\$ 1,307
162	<b>(Over)/Under Balance</b>	In 155 + In 161	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 23,666	\$ 21,839	\$ 24,260	\$ 27,716	\$ 30,876	\$ 30,725	\$ 22,710	\$ 11,959	1,307
<b>Calculation of Bad Debt with Interest</b>																
168	<b>Beginning Balance</b>		\$ 23,159	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 23,768	\$ 16,906	\$ 16,596	\$ 17,879	\$ 18,697	\$ 15,167	\$ (65)	\$ 23,159
169	Forecast Bad Debt	In 146	-	-	-	-	-	-	21,911	15,477	14,305	14,182	15,866	26,558	-	108,300
170	Projected Revenues with int.	In 184 * 189	-	-	-	-	-	-	(5,086)	(15,617)	(12,896)	(13,082)	(19,604)	(42,196)	(50,003)	(158,484)
171	Projected Unbilled Revenue	In 185 * 189	-	-	-	-	-	-	(23,777)	(24,021)	(24,223)	(24,586)	(24,453)	(24,081)	(145,142)	
172	Reverse Prior Month Unbilled		-	-	-	-	-	-	-	24,021	24,223	24,586	24,453	24,081	145,142	
173	Bad Debt Billed	In 152	-	-	-	-	-	-	-	-	-	-	-	-	-	-
174	Add Interest	In 161	-	-	-	-	-	-	101	99	115	130	133	119	698	
175	Add Net Adjustments	In 153	-	-	-	-	-	-	-	-	-	-	-	-	-	-
176	Monthly (Over)/Under Recovery		\$ 23,159	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 16,917	\$ 16,623	\$ 17,917	\$ 18,746	\$ 15,226	\$ 20	\$ (25,988)	\$ (26,328)
178	Average Monthly Balance	(In 168 + 176) / 2	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 23,666	\$ 20,343	\$ 16,765	\$ 17,256	\$ 18,312	\$ 16,962	\$ 7,593	\$ (13,027)	
180	Interest Applied	In 159 * In 178 / 365 * Days of Month	100	104	104	95	105	102	91	72	77	82	73	34	-	\$ 1,038
182	<b>(Over)/Under Balance</b>	-In 174 + In 176 + In 180	\$ 23,159	\$ 23,259	\$ 23,362	\$ 23,467	\$ 23,561	\$ 23,666	\$ 16,906	\$ 16,596	\$ 17,879	\$ 18,697	\$ 15,167	\$ (65)	\$ (25,988)	\$ (25,988)
184	Forecast Therm Sales	In 53	-	-	-	-	-	-	870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316	27,125,444
185	Unbilled Therm	In 55	-	-	-	-	-	-	4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	-	-
187	COG Rate Without Interest	Sch. 3, pg. 4, In 245 col. (c)	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048	\$ 0.0048
189	COG With Interest	Sch. 3, pg. 4, In 245 col. (d)	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058	\$ 0.0058
193	<b>Total Interest</b>	Ins 48 + 119 + 180	\$ 19,417	\$ 20,151	\$ 20,241	\$ 18,364	\$ 20,413	\$ 19,843	\$ 19,566	\$ 17,759	\$ 18,213	\$ 18,198	\$ 16,705	\$ 13,968	\$ -	\$ 222,837

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

2

3 Off Peak 2022 Summer Cost of Gas Filing

4 Adjustments to Gas Costs

5

6 Adjustments		Prior Period	Refunds from	Broker	Fuel Financing	Transportation	Interruptible	Off System	Capacity	Net Option	Fixed Price	Total
7 (a)		Adjustments	Suppliers /	Revenue	(e)	CGA Revenues	Sales Margin	Sales Margin	Release Margin	Premiums	Option	Adjustments
8		(b)	Pipelines	(d)	(e)	(f)	(g)	(h)	(i)	(j)	Administrative	(m)
9			(c)								Costs	
9	Nov-19	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	Dec-19	-	-	-	-	-	-	-	-	-	-	-
11	Jan-20	-	-	-	-	-	-	-	-	-	-	-
12	Feb-20	-	-	-	-	-	-	-	-	-	-	-
13	Mar-20	-	-	-	-	-	-	-	-	-	-	-
14	Apr-20	-	-	-	-	-	-	-	-	-	-	-
15	May-20	-	-	-	-	-	-	-	(149,464)	-	-	(149,464)
16	Jun-20	-	-	-	-	-	-	-	(141,180)	-	-	(141,180)
17	Jul-20	-	-	-	-	-	-	-	(211,505)	-	-	(211,505)
18	Aug-20	-	-	-	-	-	-	-	(224,684)	-	-	(224,684)
19	Sep-20	-	-	-	-	-	-	-	(162,433)	-	-	(162,433)
20	Oct-20	-	-	-	-	-	-	-	(191,448)	-	-	(191,448)
21												
22	Total Off Peak Period	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,080,715)	\$ -	\$ -	\$ (1,080,715)

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

REDACTED  
Updated Schedule 5A  
Page 1 of 2

2  
3 Off Peak 2022 Summer Cost of Gas Filing

4 Demand Costs

5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46			
	(a)	Peak (b)	Reference (c)	May-22 (d)	Jun-22 (e)	Jul-22 (f)	Aug-22 (g)	Sep-22 (h)	Oct-22 (i)	Off Peak May - Oct Total (j)	Peak May - Oct Total (k)																																	
11	Supply																																											
12	Niagara Supply		Sch 5B, In 9 * Sch 5C In 9 x days	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -																																	
13	Subtotal Supply Demand & Reservation Charges			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -																																	
15	Pipeline																																											
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, In 12 * Sch 5C In 12 x days																																									
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, In 13 * Sch 5C In 14 x days																																									
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, In 14 * Sch 5C In 16 x days																																									
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, In 15 * Sch 5C In 18 x days																																									
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, In 16 * Sch 5C In 20 x days																																									
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, In 17 * Sch 5C In 22 x days																																									
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, In 18 * Sch 5C In 24 x days																																									
23	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7		Sch 5B, In * Sch 5C In 25 x days																																									
24	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, In 19 * Sch 5C In 28 x days																																									
25	Portland Natural Gas Trans Service		Sch 5B, In 20 * Sch 5C In 30 x days																																									
26	Portland Natural Gas		Sch 5B, In 21 * Sch 5C In 31 x days																																									
27	ANE (TransCanada via Union to Iroquois)		Sch 5B, In 22 * Sch 5C In 48 x days																																									
28	TransCanada via Union to Portland		Sch 5B, In 23 * Sch 5C In 49 x days																																									
29	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, In 24 * Sch 5C In 34 x days																																									
30	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, In 25 * Sch 5C In 36 x days																																									
31	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, In 26 * Sch 5C In 38 x days																																									
32	National Fuel FST 2358	peak	Sch 5B, In 27 * Sch 5C In 40 x days																																									
34	Subtotal Pipeline Demand Charges			\$ 1,640,391	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 4,954,402	\$ 4,903,685																																
36	Peaking Supply																																											
37	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, In 30 * Sch 5C In 28 x days	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -																																
38	Granite Ridge Demand	peak	Sch 5B, In 31 * Sch 5C In 59 x days	-	-	-	-	-	-	-	-	-																																
39	DOMAC Demand NSB041	peak	Per Contract	-	-	-	-	-	-	-	-	-																																
40	Subtotal Peaking Demand Charges			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -																																
42	Subtotal Supply, Pipeline & Peaking		In 13 + In 34 + In 40	\$ 1,640,391	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 1,643,539	\$ 4,954,402	\$ 4,903,685																																
44	Less Transportation Capacity Credit			\$ (555,436)	\$ (556,502)	\$ (556,502)	\$ (556,502)	\$ (556,502)	\$ (556,502)	\$ (556,502)	\$ (1,677,561)	\$ (1,660,388)																																
46	Total Supply, Pipeline & Peaking Demand			\$ 1,084,955	\$ 1,087,037	\$ 1,087,037	\$ 1,087,037	\$ 1,087,037	\$ 1,087,037	\$ 1,087,037	\$ 3,276,842	\$ 3,243,297																																

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2

Updated Schedule 5A

3 Off Peak 2022 Summer Cost of Gas Filing

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4 Demand Costs

47

48 Storage

49	Dominion - Demand	peak	Sch 5B, In 35 * Sch 5C In 63 x days	\$ 1,748	\$ 1,748	\$ 1,748	\$ 1,748	\$ 1,748	\$ 1,748	\$ -	\$ 10,488
50	Dominion - Storage	peak	Sch 5B, In 36 * Sch 5C In 64 x days	1,489	1,489	1,489	1,489	1,489	1,489	-	8,935
51	Honeoye - Demand	peak	Sch 5B, In 37 * Sch 5C In 67 x days	8,351	8,351	8,351	8,351	8,351	8,351	-	50,105
52	National Fuel - Demand	peak	Sch 5B, In 39 * Sch 5C In 69 x days	16,053	16,053	16,053	16,053	16,053	16,053	-	96,318
53	National Fuel - Capacity	peak	Sch 5B, In 40 * Sch 5C In 70 x days	31,930	31,930	31,930	31,930	31,930	31,930	-	191,580
54	Tenn Gas Pipeline - Demand	peak	Sch 5B, In 41 * Sch 5C In 73 x days	28,603	28,603	28,603	28,603	28,603	28,603	-	171,615
55	Tenn Gas Pipeline - Capacity	peak	Sch 5B, In 42 * Sch 5C In 74 x days	27,931	27,931	27,931	27,931	27,931	27,931	-	167,586
56											
57	<b>Subtotal Storage Demand Costs</b>			\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ 116,105	\$ -	\$ 696,628
58											
59	Less Transportation Capacity Credit			\$ (39,313)	\$ (39,313)	\$ (39,313)	\$ (39,313)	\$ (39,313)	\$ (39,313)	\$ -	\$ (235,878)
60											
61	<b>Total Storage Demand Costs</b>		In 57 + In 59	\$ 76,792	\$ 76,792	\$ 76,792	\$ 76,792	\$ 76,792	\$ 76,792	\$ -	\$ 460,750
62											
63	<b>Total Demand Charges</b>		In 42 + In 57	\$ 1,756,496	\$ 1,759,644	\$ 1,759,644	\$ 1,759,644	\$ 1,759,644	\$ 1,759,644	\$ 4,954,402	\$ 5,600,313
64											
65	Total Transportation Capacity Credit		In 44 + In 59	\$ (594,749)	\$ (595,815)	\$ (595,815)	\$ (595,815)	\$ (595,815)	\$ (595,815)	\$ (1,677,561)	\$ (1,896,266)
66											
67	<b>Total Demand Charges less Cap. Cr.</b>		In 63 + In 65	\$ 1,161,746	\$ 1,163,829	\$ 1,163,829	\$ 1,163,829	\$ 1,163,829	\$ 1,163,829	\$ 3,276,842	\$ 3,704,047
68											
69											
70	Monthly Off Peak Demand			\$ 990,382	\$ 993,530	\$ 993,530	\$ 993,530	\$ 993,530	\$ 993,530	\$ 4,954,402	\$ -
71	Monthly Off Peak Transportation Cap Credit			(335,343)	(336,409)	(336,409)	(336,409)	(336,409)	(336,409)	(1,677,561)	-
72	<b>Total Off Peak Demand</b>			\$ 655,039	\$ 657,121	\$ 657,121	\$ 657,121	\$ 657,121	\$ 657,121	\$ 3,276,842	\$ -
73											
74	Monthly Peak Demand			\$ 766,114	\$ 766,114	\$ 766,114	\$ 766,114	\$ 766,114	\$ 766,114	\$ -	\$ 5,600,313
75	Monthly Peak Transportation Cap Credit			(259,406)	(259,406)	(259,406)	(259,406)	(259,406)	(259,406)	-	(1,896,266)
76	<b>Total Peak Demand</b>			\$ 506,708	\$ 506,708	\$ 506,708	\$ 506,708	\$ 506,708	\$ 506,708	\$ -	\$ 3,704,047



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

2  
3 **Off Peak 2022 Summer Cost of Gas Filing**  
4 **Demand Volumes**

5									
6		Peak	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	<b>Supply</b>								
9	Niagara Supply			-	-	-	-	-	-
10									
11	<b>Pipeline</b>								
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
	Tenn Gas Pipeline		358905 FTA Z6-Z6	40,000	40,000	40,000	40,000	40,000	40,000
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		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
21	Portland Natural Gas		FTN	5,000	5,000	5,000	5,000	5,000	5,000
22	ANE (TransCanada via Union to Iroquois)		Dawn - 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	5,077	5,077	5,077	5,077	5,077	5,077
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	<b>Peaking</b>								
30	Tenn Gas Pipeline (Concord Lateral)	peak		-	-	-	-	-	-
31	Granite Ridge Demand	peak		-	-	-	-	-	-
32	DOMAC Liquid Demand Charge	peak	NSB041	-	-	-	-	-	-
33									
34	<b>Storage</b>								
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-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
40	National Fuel - Capacity Reservation	peak	FSS-1 2357	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

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

2 d/b/a Liberty Utilities

3 Off Peak 2022 Summer Cost of Gas Filing

4 Demand Rates

5

6 Tariff Rates

7

8 Supply

9 Niagara Supply \$ - Per Contract \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -

10 Pipeline

12 Iroquois Gas RTS 470-01 \$ 5.2357 Forth Revised Sheet No. 4 \$ 0.1689 \$ 0.1745 \$ 0.1689 \$ 0.1689 \$ 0.1745 \$ 0.1689 \$ 0.1708 \$ 0.1745 \$ 0.1689 \$ 0.1689 \$ 0.1870 \$ 0.1689 \$ 0.1745

14 Tenn Gas Pipeline 95346 Z5-Z6 \$ 6.2957 17th Rev Sheet No. 14 \$ 0.4746 \$ 0.4904 \$ 0.4746 \$ 0.4746 \$ 0.4904 \$ 0.4746 \$ 0.4799 \$ 0.4904 \$ 0.4746 \$ 0.4746 \$ 0.5254 \$ 0.4746 \$ 0.4904

16 Tenn Gas Pipeline 2302 Z5-Z6 \$ 6.2957 17th Rev Sheet No. 14 \$ 0.2031 \$ 0.2099 \$ 0.2031 \$ 0.2031 \$ 0.2099 \$ 0.2031 \$ 0.2053 \$ 0.2099 \$ 0.2031 \$ 0.2031 \$ 0.2248 \$ 0.2031 \$ 0.2099

18 Tenn Gas Pipeline 8587 Z0-Z6 \$ 20.3736 FT-A (Z0 - Z6) \$ 0.6572 \$ 0.6791 \$ 0.6572 \$ 0.6572 \$ 0.6791 \$ 0.6572 \$ 0.6645 \$ 0.6791 \$ 0.6572 \$ 0.6572 \$ 0.7276 \$ 0.6572 \$ 0.6791

20 Tenn Gas Pipeline 8587 Z1-Z6 \$ 18.0875 FT-A (Z1 - Z6) \$ 0.5835 \$ 0.6029 \$ 0.5835 \$ 0.5835 \$ 0.6029 \$ 0.5835 \$ 0.5900 \$ 0.6029 \$ 0.5835 \$ 0.5835 \$ 0.6460 \$ 0.5835 \$ 0.6029

22 Tenn Gas Pipeline 8587 Z4-Z6 \$ 7.1645 FT-A (Z4 - Z6) \$ 0.2311 \$ 0.2388 \$ 0.2311 \$ 0.2311 \$ 0.2388 \$ 0.2311 \$ 0.2337 \$ 0.2388 \$ 0.2311 \$ 0.2311 \$ 0.2559 \$ 0.2311 \$ 0.2388

24 TGP Dracut 42076 FTA Z6-Z6 \$ 4.1818 17th Rev Sheet No. 14 \$ 0.1349 \$ 0.1394 \$ 0.1349 \$ 0.1349 \$ 0.1394 \$ 0.1349 \$ 0.1364 \$ 0.1394 \$ 0.1349 \$ 0.1349 \$ 0.1494 \$ 0.1349 \$ 0.1394

26 TGP Dracut 358905 FTA Z6-Z6 \$ 4.1818 17th Rev Sheet No. 14 \$ 0.1349 \$ 0.1394 \$ 0.1349 \$ 0.1349 \$ 0.1394 \$ 0.1349 \$ 0.0227 \$ 0.1394 \$ 0.1349 \$ 0.1349 \$ 0.1494 \$ 0.1349 \$ 0.1394

28 TGP Concord Lateral Firm Transportation \$ 12.2113 Per contract \$ 0.3939 \$ 0.4070 \$ 0.3939 \$ 0.3939 \$ 0.4070 \$ 0.3939 \$ 0.3983 \$ 0.4070 \$ 0.3939 \$ 0.3939 \$ 0.4361 \$ 0.3939 \$ 0.4070

30 Portland Natural Gas FT-1999-001 \$ 18.2633 Negot Dmd /CMDY=Part 4.1 V7 \$ 0.5891 \$ 0.6088 \$ 0.5891 \$ 0.5891 \$ 0.6088 \$ 0.5891 \$ 0.5957 \$ 0.6088 \$ 0.5891 \$ 0.5891 \$ 0.6523 \$ 0.5891 \$ 0.6088

32 Portland Natural Gas FTN \$ 22.8125 Negot Dmd /CMDY=Part 4.1 V7 \$ 0.7359 \$ 0.7604 \$ 0.7359 \$ 0.7359 \$ 0.7604 \$ 0.7359 \$ 0.7441 \$ 0.7604 \$ 0.7359 \$ 0.7359 \$ 0.8147 \$ 0.7359 \$ 0.7604

34 Tenn Gas Pipeline 632 Z4-Z6 (stg) \$ 7.1645 17th Rev Sheet No. 14 \$ 0.2311 \$ 0.2388 \$ 0.2311 \$ 0.2311 \$ 0.2388 \$ 0.2311 \$ 0.2337 \$ 0.2388 \$ 0.2311 \$ 0.2311 \$ 0.2559 \$ 0.2311 \$ 0.2388

36 Tenn Gas Pipeline 11234 Z4-Z6(stg) \$ 7.1645 17th Rev Sheet No. 14 \$ 0.2311 \$ 0.2388 \$ 0.2311 \$ 0.2311 \$ 0.2388 \$ 0.2311 \$ 0.2337 \$ 0.2388 \$ 0.2311 \$ 0.2311 \$ 0.2559 \$ 0.2311 \$ 0.2388

38 Tenn Gas Pipeline 11234 Z5-Z6(stg) \$ 6.2957 17th Rev Sheet No. 14 \$ 0.2031 \$ 0.2099 \$ 0.2031 \$ 0.2031 \$ 0.2099 \$ 0.2031 \$ 0.2053 \$ 0.2099 \$ 0.2031 \$ 0.2031 \$ 0.2248 \$ 0.2031 \$ 0.2099

40 National Fuel FST N02358 \$ 4.5274 4.010 Version 31.0.1 Pg 1 \$ 0.1460 \$ 0.1509 \$ 0.1460 \$ 0.1460 \$ 0.1509 \$ 0.1460 \$ 0.1477 \$ 0.1509 \$ 0.1460 \$ 0.1460 \$ 0.1617 \$ 0.1460 \$ 0.1509

42 ANE Union Gas \$ 3.6665

43 TransCanada Pipelines Limited \$ 11.9842 Union Parkway to Iroquois

44 Delivery Pressure Demand Charge 0.6083 Union Parkway to Iroquois

45 Sub Total Demand Charges 16.2590

46 Conversion rate GJ to MMBTU 1.0551

47 Conversion rate to US\$ 1.2589 1/0/1900

48 Demand Rate/US\$ 13.6260 \$ 0.4395 \$ 0.4542 \$ 0.4395 \$ 0.4395 \$ 0.4542 \$ 0.4395 \$ 0.4444 \$ 0.4542 \$ 0.4395 \$ 0.4395 \$ 0.4866 \$ 0.4395 \$ 0.4542

50 Union Gas \$ 3.6665

51 TransCanada Pipelines Limited \$ 20.4218

52 Delivery Pressure Demand Charge \$ 0.6083

53 Sub Total Demand Charges \$ 24.6966

54 Conversion rate GJ to MMBTU \$ 1.0551

55 Conversion rate to US\$ 1.2589 \$0.0000

56 Demand Rate/US\$ 20.6972 \$ 0.6677 \$ 0.6899 \$ 0.6677 \$ 0.6677 \$ 0.6899 \$ 0.6677 \$ 0.6751 \$ 0.6899 \$ 0.6677 \$ 0.6677 \$ 0.7392 \$ 0.6677 \$ 0.6899

57

58 Peaking

59 Granite Ridge Demand \$ - Per Contract \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -

60 DOMAC Demand NSB041 \$ - Per Contract \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -

61

62 Storage

63 Dominion - Demand GSS 300076 \$ 1.8716 GSS Settled,Tariff Rec #10.30 V \$ 0.0604 \$ 0.0624 \$ 0.0604 \$ 0.0604 \$ 0.0624 \$ 0.0604 \$ 0.0612 \$ 0.0624 \$ 0.0604 \$ 0.0604 \$ 0.0668 \$ 0.0604 \$ 0.0624

64 Dominion - Capacity GSS 300076 \$ 0.0145 GSS Settled,Tariff Rec #10.30 V \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005 \$ 0.0005

65 \$ 1.8861 \$ 0.0608 \$ 0.0629 \$ 0.0608 \$ 0.0608 \$ 0.0629 \$ 0.0608 \$ 0.0617 \$ 0.0629 \$ 0.0608 \$ 0.0608 \$ 0.0674 \$ 0.0608 \$ 0.0629

66

67 Honeoye - Demand SS-NY \$ 6.1299 Sub 1st Rev Sheet No. 5 \$ 0.1977 \$ 0.2043 \$ 0.1977 \$ 0.1977 \$ 0.2043 \$ 0.1977 \$ 0.2004 \$ 0.2043 \$ 0.1977 \$ 0.1977 \$ 0.2189 \$ 0.1977 \$ 0.2043

68

69 National Fuel - Demand FSS-1 2357 \$ 2.6325 4.020 Version 26.0.0 Pg 1 \$ 0.0849 \$ 0.0878 \$ 0.0849 \$ 0.0849 \$ 0.0878 \$ 0.0849 \$ 0.0861 \$ 0.0878 \$ 0.0849 \$ 0.0849 \$ 0.0940 \$ 0.0849 \$ 0.0878

70 National Fuel - Capacity FSS-1 2357 \$ 0.0476 4.020 Version 26.0.0 Pg 1 \$ 0.0015 \$ 0.0016 \$ 0.0015 \$ 0.0015 \$ 0.0016 \$ 0.0015 \$ 0.0016 \$ 0.0016 \$ 0.0016 \$ 0.0015 \$ 0.0015 \$ 0.0017 \$ 0.0015 \$ 0.0016

71 \$ 2.6801 \$ 0.0865 \$ 0.0893 \$ 0.0865 \$ 0.0865 \$ 0.0893 \$ 0.0865 \$ 0.0876 \$ 0.0893 \$ 0.0865 \$ 0.0865 \$ 0.0957 \$ 0.0865 \$ 0.0893

72

73 Tenn Gas Pipeline FS-MA 523 \$ 1.3094 20th Rev Sheet No.61 \$ 0.0422 \$ 0.0436 \$ 0.0422 \$ 0.0422 \$ 0.0436 \$ 0.0422 \$ 0.0428 \$ 0.0436 \$ 0.0422 \$ 0.0422 \$ 0.0468 \$ 0.0422 \$ 0.0436

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
2  
3 Off Peak 2022 Summer Cost of Gas Filing  
4 Supply and Commodity Costs, Volumes and Rates

REDACTED  
Updated Schedule 6  
Page 1 of 5

5	6 For Month of:	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Off-Peak	
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	May - Oct	
8									(i)	
9	<b>Supply and Commodity Costs</b>									
10	<b>11 Pipeline Gas:</b>									
12	Dawn Supply	In 63 * In 104	[REDACTED]							
13	Niagara Supply	In 64 * In 109								
14	TGP Supply (Gulf)	In 65 * In 129								
15	Dracut Supply 1 - Baseload	In 66 * In 114								
16	Dracut Supply 2 - Swing	In 67 * In 119								
	Dracut Supply 3 - Swing									
17	City Gate Delivered Supply	In 68 * In 135								
18	LNG Truck	In 69 * In 137								
19	Propane Truck	In 70 * In 139								
20	PNGTS	In 71 * In 144								
21	Portland Natural Gas									
22	TGP Supply (Zone 4)	In 73 * In 154								
23										
24	Subtotal Pipeline Gas Costs		\$ 2,582,425	\$ 1,948,176	\$ 1,951,410	\$ 1,908,418	\$ 1,867,983	\$ 2,854,727	\$ 13,129,445	
25										
26	<b>Volumetric Transportation Costs</b>									
27	Dawn Supply	In 63 * In 202	[REDACTED]							
28	Niagara Supply	In 64 * In 213								
29	TGP Supply (Zone 4)	In 73 * In 251								
30	Dracut Supply 1 - Baseload	In 66 * In 262								
31	Dracut Supply 2 - Swing	In 67 * In 262								
	Dracut Supply 3 - Swing									
32	City Gate Delivered Supply	In 68 * In 262								
33	TGP Storage - Withdrawals	In 78 * In 177								
34										
35	Total Volumetric Transportation Costs		\$ 88,990	\$ 71,093	\$ 70,660	\$ 70,003	\$ 71,501	\$ 87,078	\$ 459,325	
36										
37	<b>Less - Gas Refill:</b>									
38	LNG Truck	In 87 * In 161	[REDACTED]							
39	Propane	In 88 * In 162								
40	TGP Storage Refill	In 89 * In 127								
41	Storage Refill (Trans.)	In 89 * In 241								
42										
43	Subtotal Refills		\$ (960,246)	\$ (1,223,872)	\$ (1,393,945)	\$ (1,367,756)	\$ (1,088,979)	\$ (566,192)	\$ (6,600,989)	
44										
45	Total Supply & Pipeline Commodity Costs	In 24 + In 35 + In 43	\$ 1,711,170	\$ 795,397	\$ 628,125	\$ 610,666	\$ 850,505	\$ 2,375,613	\$ 6,971,475	
46										
47	<b>Storage Gas:</b>									
48	TGP Storage - Withdrawals	In 78 * In 169	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
49										
50	<b>Produced Gas:</b>									
51	LNG Vapor	In 81 * In 156	[REDACTED]							
52	Propane	In 82 * In 158								
53										
54	Total Produced Gas	In 51 + In 52	\$ 13,993	\$ 13,159	\$ 12,913	\$ 12,877	\$ 13,652	\$ 15,911	\$ 82,504	
55										
56										
57	Total Commodity Gas & Trans. Costs	In 45 + In 48 + In 54	\$ 1,725,162	\$ 808,556	\$ 641,038	\$ 623,542	\$ 864,157	\$ 2,391,524	\$ 7,053,979	

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

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3 Off Peak 2022 Summer Cost of Gas Filing

4 Supply and Commodity Costs, Volumes and Rates

59

Updated Schedule 6

60 **Volumes (Therms)**

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61

62 **Pipeline Gas:** See Schedule 11A

63	Dawn Supply	739,535	95,658	-	-	206,295	636,518	1,678,006
64	Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
65	TGP Supply (Gulf)	13,120	-	-	-	-	384,326	397,446
66	Dracut Supply 1 - Baseload	-	-	-	-	-	-	-
67	Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
	Dracut Supply 3 - Swing	-	-	-	-	-	-	-
68	City Gate Delivered Supply	-	-	-	-	-	-	-
69	LNG Truck	44,883	18,131	-	-	55,566	20,602	139,181
70	Propane Truck	79,409	71,899	69,472	69,279	73,449	81,696	445,204
71	PNGTS	205,081	146,300	119,612	125,908	176,916	218,093	991,910
72	Portland Natural Gas	152,602	3,126	-	-	2,555	574,003	732,286
73	TGP Supply (Zone 4)	5,386,659	4,708,479	4,708,982	4,696,535	4,819,522	5,546,088	29,866,267
74								
75	Subtotal Pipeline Volumes	7,289,702	5,584,403	5,440,551	5,437,523	5,925,726	8,585,177	38,263,081
76								

77 **Storage Gas:**

78	TGP Storage	-	-	-	-	-	-	-
79								

80 **Produced Gas:**

81	LNG Vapor	20,025	18,131	17,519	17,470	18,522	20,602	112,269
82	Propane	-	-	-	-	-	-	-
83								
84	Subtotal Produced Gas	20,025	18,131	17,519	17,470	18,522	20,602	112,269
85								

86 **Less - Gas Refill:**

87	LNG Truck	(44,883)	(18,131)	-	-	(55,566)	(20,602)	(139,181)
88	Propane	(79,409)	(71,899)	(69,472)	(69,279)	(73,449)	(81,696)	(445,204)
89	TGP Storage Refill	(2,188,222)	(2,766,568)	(3,120,796)	(3,057,929)	(2,444,250)	(1,262,380)	(14,840,145)
90								
91	Subtotal Refills	(2,312,514)	(2,856,598)	(3,190,268)	(3,127,208)	(2,573,265)	(1,364,677)	(15,424,530)
92								

93 **Total Sendout Volumes**

94		4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820
95								
96								

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

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3 Off Peak 2022 Summer Cost of Gas Filing

4 Supply and Commodity Costs, Volumes and Rates

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98 Gas Costs and Volumetric Transportation Rates

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100 Pipeline Gas:

101 Dawn Supply

102 NYMEX Price Sch 7, In 10/10

103 Basis Differential

104 Net Commodity Costs

105

106 Niagara Supply

107 NYMEX Price Sch 7, In 10/10

108 Basis Differential

109 Net Commodity Costs

110

111 Dracut Supply 1 - Baseload

112 Commodity Costs - NYMEX Price Sch 7, In 10 / 10

113 Basis Differential

114 Net Commodity Costs

115

116 Dracut Supply 2 - Swing

117 Commodity Costs - NYMEX Price Sch 7, In 10 / 10

118 Basis Differential

119 Net Commodity Costs

120

121 Dracut Supply 3 - Swing

122 Commodity Costs - NYMEX Price Sch 7, In 10 / 10

123 Basis Differential

124 Net Commodity Costs

125

126 TGP Supply (Gulf)

127 NYMEX Price Sch 7, In 10/10

128 Basis Differential

129 Net Commodity Costs

130

131

132 TGP Citygate Supply

133 NYMEX Price Sch 7, In 10/10

134 Basis Differential

135 Net Commodity Costs

136

137 LNG Truck

Sch 7, In 10/10

138

139 Propane Truck

NYMEX - Propane

140

141 PNGTS

142 NYMEX Price Sch 7, In 10/10

143 Additional Cost

144 Net Commodity Cost

145

146 PNGTS EXP

147 NYMEX Price Sch 7, In 10/10

148 Basis Differential

149 Net Commodity Cost

150

151 TGP Supply (Zone 4)

152 NYMEX Price Sch 7, In 10/10

153 Basis Differential

154 Net Commodity Cost

155

156 LNG Vapor (Storage)

Sch 13, In 97 /10

157

158 Propane

Sch 13, In 67 /10

159

160 Storage Refill:

161 LNG Truck In 137

162 Propane In 139

163

164

								Average Rate
102 NYMEX Price	Sch 7, In 10/10							
103 Basis Differential								
104 Net Commodity Costs								
107 NYMEX Price	Sch 7, In 10/10							
108 Basis Differential								
109 Net Commodity Costs								
112 Commodity Costs - NYMEX Price	Sch 7, In 10 / 10							
113 Basis Differential								
114 Net Commodity Costs								
117 Commodity Costs - NYMEX Price	Sch 7, In 10 / 10							
118 Basis Differential								
119 Net Commodity Costs								
122 Commodity Costs - NYMEX Price	Sch 7, In 10 / 10							
123 Basis Differential								
124 Net Commodity Costs								
127 NYMEX Price	Sch 7, In 10/10							
128 Basis Differential								
129 Net Commodity Costs								
133 NYMEX Price	Sch 7, In 10/10							
134 Basis Differential								
135 Net Commodity Costs								
137 LNG Truck	Sch 7, In 10/10	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
139 Propane Truck	NYMEX - Propane	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
142 NYMEX Price	Sch 7, In 10/10							
143 Additional Cost								
144 Net Commodity Cost								
147 NYMEX Price	Sch 7, In 10/10							
148 Basis Differential								
149 Net Commodity Cost								
152 NYMEX Price	Sch 7, In 10/10							
153 Basis Differential								
154 Net Commodity Cost		\$0.3562	\$0.3524	\$0.3620	\$0.3531	\$0.3135	\$0.3150	\$0.3420
156 LNG Vapor (Storage)	Sch 13, In 97 /10	\$0.6988	\$0.7258	\$0.7371	\$0.7371	\$0.7371	\$0.7723	\$0.7347
158 Propane	Sch 13, In 67 /10	\$1.1475	\$1.0155	\$0.9197	\$0.8429	\$0.7781	\$0.7194	\$0.9038
161 LNG Truck	In 137	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
162 Propane	In 139	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

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3 Off Peak 2022 Summer Cost of Gas Filing

4 Supply and Commodity Costs, Volumes and Rates

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182 Per Unit Volumetric Transportation Rates

183 Dawn Supply Volumetric Transportation Charge

184 Commodity Costs Ln 104

185

		Average Rate						
186	TransCanada - Commodity Rate/GJ Dawn - Parkway to Iroquois	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030
187	Conversion Rate GL to MMBTU	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
188	Conversion Rate to US\$ 1/0/1900	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589
189	Commodity Rate/US\$ In 186 x In 187 x In 188	\$0.00040	\$0.00040	\$0.00040	\$0.00040	\$0.00040	\$0.00040	\$0.00040
190	TransCanada Fuel % Dawn - Parkway to Iroquois	0.74%	0.67%	0.00%	0.00%	0.00%	0.00%	0.23%
191	TransCanada Fuel * Percentage In 184 x In 190	\$0.00283	\$0.00256	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00090
192	Subtotal TransCanada	<b>\$0.00323</b>	<b>\$0.00296</b>	<b>\$0.00040</b>	<b>\$0.00040</b>	<b>\$0.00040</b>	<b>\$0.00040</b>	<b>\$0.00130</b>
193	IGTS - Z1 RTS Commodity Forth Revised Sheet No. 4	\$0.00034	\$0.00034	\$0.00034	\$0.00034	\$0.00034	\$0.00034	\$0.00034
194	IGTS - Z1 RTS ACA Rate Commodity Forth Revised Sheet No. 4	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
195	IGTS - Z1 RTS Deferred Asset Surcharge Forth Revised Sheet No. 4	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
196	Subtotal IGTS - Trans Charge - Z1 RTS Commodity	<b>\$0.00046</b>	<b>\$0.00046</b>	<b>\$0.00046</b>	<b>\$0.00046</b>	<b>\$0.00046</b>	<b>\$0.00046</b>	<b>\$0.00046</b>
197	TGP NET-NE - Comm. Segments 3 & 4 19th Rev Sheet No. 15	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
198	IGTS -Fuel Use Factor - Percentage Forth Revised Sheet No. 4	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
199	IGTS -Fuel Use Factor - Fuel * Percentage In 184 x In 198	<b>\$0.00382</b>	<b>\$0.00384</b>	<b>\$0.00387</b>	<b>\$0.00385</b>	<b>\$0.00384</b>	<b>\$0.00385</b>	<b>\$0.00385</b>
200	TGP FTA Fuel Charge % Z 5-6 17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
201	TGP FTA Fuel * Percentage In 184 x In 200	<b>\$0.00329</b>	<b>\$0.00330</b>	<b>\$0.00333</b>	<b>\$0.00331</b>	<b>\$0.00330</b>	<b>\$0.00331</b>	<b>\$0.00331</b>
202	<b>Total Volumetric Transportation Charge - Dawn Supply</b>	<b>\$0.01092</b>	<b>\$0.01068</b>	<b>\$0.00818</b>	<b>\$0.00814</b>	<b>\$0.00812</b>	<b>\$0.00814</b>	<b>\$0.00903</b>

203

204

205 Niagara Supply Volumetric Transportation Charge

206 Commodity Costs Ln 109

207

208	TGP FTA - FTA Z 5-6 Comm. Rate 19th Rev Sheet No. 15	\$0.00705	\$0.00705	\$0.00705	\$0.00705	\$0.00705	\$0.00705	\$0.00705
209	TGP FTA - FTA Z 5-6 - ACA Rate 19th Rev Sheet No. 15	<u>\$0.00012</u>	<u>\$0.0001</u>	<u>\$0.0001</u>	<u>\$0.0001</u>	<u>\$0.0001</u>	<u>\$0.0001</u>	<u>\$0.0001</u>
210	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate	<b>\$0.00717</b>	<b>\$0.0072</b>	<b>\$0.0072</b>	<b>\$0.0072</b>	<b>\$0.0072</b>	<b>\$0.0072</b>	<b>\$0.0072</b>
211	TGP FTA Fuel Charge % Z 5-6 17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
212	TGP FTA Fuel * Percentage In 206 x In 211	<b>\$0.00311</b>	<b>\$0.00313</b>	<b>\$0.00316</b>	<b>\$0.00314</b>	<b>\$0.00313</b>	<b>\$0.00314</b>	<b>\$0.00314</b>
213	<b>Total Volumetric Transportation Rate - Niagara Supply</b>	<b>\$0.01028</b>	<b>\$0.01030</b>	<b>\$0.01033</b>	<b>\$0.01031</b>	<b>\$0.01030</b>	<b>\$0.01031</b>	<b>\$0.01031</b>

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1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

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3 Off Peak 2022 Summer Cost of Gas Filing

4 Supply and Commodity Costs, Volumes and Rates

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220 TGP Direct Volumetric Transportation Charge

221 Commodity Costs Ln 127

222

223 TGP - Max Comm. Base Rate - Z 0-6 19th Rev Sheet No. 15

224 TGP - Max Commodity ACA Rate - Z 0-6 19th Rev Sheet No. 15

225 Subtotal TGP - Max Comm. Rate Z 0-6

226 Prorated Percentage

227 Prorated TGP - Max Commodity Rate - Z 0-6

228 TGP - Max Comm. Base Rate - Z 1-6 19th Rev Sheet No. 15

229 TGP - Max Commodity ACA Rate - Z 1-6 19th Rev Sheet No. 15

230 Subtotal TGP - Max Commodity Rate - Z 1-6

231 Prorated Percentage

232 Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6

233 TGP - Fuel Charge % - Z 0-6 17th Rev Sheet No. 32

234 Prorated Percentage

235 Prorated TGP Fuel Charge % - Z 0-6

236 TGP - Fuel Charge % - Z 1-6 17th Rev Sheet No. 32

237 Prorated Percentage

238 Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6

239 TGP - Fuel Charge % - Z 0-6 In 221 x In 235

240 TGP - Fuel Charge % - Z 1-6 In 221 x In 238

241 Total Volumetric Transportation Rate - TGP (Direct)

242

243 TGP (Zone 4 Purchase) Volumetric Transportation Charge

244 Commodity Costs Ln 127

245

246 TGP - Max Comm. Base Rate - Z 4-6 19th Rev Sheet No. 15

247 TGP - Max Commodity ACA Rate - Z 4-6 19th Rev Sheet No. 15

248 Subtotal TGP - Max Commodity Rate - Z 4-6

249 TGP - Fuel Charge % - Z 4-6 17th Rev Sheet No. 32

250 TGP - Fuel Charge In 244 x In 249

251 Total Vol. Trans. Rate - TGP (Zone 6)

252

253

254 TGP Dracut

255 Commodity Costs - NYMEX Price Ln 114

256

257 TGP - Trans Charge - Comm. - Z 6-6 19th Rev Sheet No. 15

258 TGP - Trans Charge - ACA Rate - Z 6-6 19th Rev Sheet No. 15

259 Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6

260 TGP - Fuel Charge % - Z 6-6 17th Rev Sheet No. 32

261 TGP - Fuel Charge In 255 x In 260

262 Total Volumetric Transportation Rate - TGP Dracut

263

264

	Average Rate						
223 TGP - Max Comm. Base Rate - Z 0-6	\$0.02672	\$0.02672	\$0.02672	\$0.02672	\$0.02672	\$0.02672	\$0.02672
224 TGP - Max Commodity ACA Rate - Z 0-6	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
225 Subtotal TGP - Max Comm. Rate Z 0-6	\$0.02684	\$0.02684	\$0.02684	\$0.02684	\$0.02684	\$0.02684	\$0.02684
226 Prorated Percentage	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
227 Prorated TGP - Max Commodity Rate - Z 0-6	\$0.00875	\$0.00875	\$0.00875	\$0.00875	\$0.00875	\$0.00875	\$0.00875
228 TGP - Max Comm. Base Rate - Z 1-6	\$0.02331	\$0.02331	\$0.02331	\$0.02331	\$0.02331	\$0.02331	\$0.02331
229 TGP - Max Commodity ACA Rate - Z 1-6	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
230 Subtotal TGP - Max Commodity Rate - Z 1-6	\$0.02343	\$0.02343	\$0.02343	\$0.02343	\$0.02343	\$0.02343	\$0.02343
231 Prorated Percentage	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
232 Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6	\$0.01579	\$0.01579	\$0.01579	\$0.01579	\$0.01579	\$0.01579	\$0.01579
233 TGP - Fuel Charge % - Z 0-6	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%
234 Prorated Percentage	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
235 Prorated TGP Fuel Charge % - Z 0-6	1.52%	1.52%	1.52%	1.52%	1.52%	1.52%	1.52%
236 TGP - Fuel Charge % - Z 1-6	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
237 Prorated Percentage	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
238 Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
239 TGP - Fuel Charge % - Z 0-6	\$0.00592	\$0.00597	\$0.00604	\$0.00605	\$0.00599	\$0.00599	\$0.00599
240 TGP - Fuel Charge % - Z 1-6	\$0.01066	\$0.01076	\$0.01088	\$0.01089	\$0.01079	\$0.01079	\$0.01080
241 Total Volumetric Transportation Rate - TGP (Direct)	\$0.04112	\$0.04128	\$0.04146	\$0.04148	\$0.04133	\$0.04131	\$0.04133

246 TGP - Max Comm. Base Rate - Z 4-6	\$0.00928	\$0.00928	\$0.00928	\$0.00928	\$0.00928	\$0.00928	\$0.00928
247 TGP - Max Commodity ACA Rate - Z 4-6	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
248 Subtotal TGP - Max Commodity Rate - Z 4-6	\$0.00940	\$0.00940	\$0.00940	\$0.00940	\$0.00940	\$0.00940	\$0.00940
249 TGP - Fuel Charge % - Z 4-6	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
250 TGP - Fuel Charge	\$0.00435	\$0.00430	\$0.00442	\$0.00431	\$0.00382	\$0.00384	\$0.00417
251 Total Vol. Trans. Rate - TGP (Zone 6)	\$0.01375	\$0.01370	\$0.01382	\$0.01371	\$0.01322	\$0.01324	\$0.01357

257 TGP - Trans Charge - Comm. - Z 6-6	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300	\$0.00300
258 TGP - Trans Charge - ACA Rate - Z 6-6	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012	\$0.00012
259 Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312
260 TGP - Fuel Charge % - Z 6-6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
261 TGP - Fuel Charge	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
262 Total Volumetric Transportation Rate - TGP Dracut	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312	\$0.00312

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

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3 **Off Peak 2022 Summer Cost of Gas Filing**

4 **NYMEX Futures @ Henry Hub**

5

6 For Month of:

7 (a) Reference (b)

8 **I. NYMEX Opening Prices as of:**

9 Opening Prices

10

	May-22 (c)	Jun-22 (d)	Jul-22 (e)	Aug-22 (f)	Sep-22 (g)	Oct-22 (h)	May - Oct Off Peak Strip Average (i)
Line 206	\$3.9770	\$4.0110	\$4.0520	\$4.0580	\$4.0420	\$4.0720	\$ 4.0353
	\$3.9770	\$4.0110	\$4.0520	\$4.0580	\$4.0420	\$4.0720	\$ 4.0353



1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 2 Off Peak 2022 Summer Cost of Gas Filing  
 3 Annual Bill Comparisons, May 20 - Oct 20 vs May 21 - Oct 21 - Residential Heating Rate R-3  
 4  
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6 November 1, 2021 - April 30, 2022  
 7 Residential Heating (R3)

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
10 Typical Usage (Therms)		62	110	123	148	132	92	667
11	8/1/2021 - Current							
12 Winter:								
13 Cust. Chg	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 15.39	\$ 92.34
14 Headblock	\$ 0.5632	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15 Tailblock	\$ 0.5632	\$ 34.92	\$ 61.95	\$ 69.27	\$ 83.35	\$ 74.34	\$ 51.81	\$ 375.65
16 HB Threshold	-							
17								
18 Summer:	8/1/2021 - Current							
19 Cust. Chg	\$ 15.39							
20 Headblock	\$ 0.5632							
21 Tailblock	\$ 0.5632							
22 HB Threshold	-							
23								
24 Total Base Rate Amount		\$ 50.31	\$ 77.34	\$ 84.66	\$ 98.74	\$ 89.73	\$ 67.20	\$ 467.99
25								
26 COG Rate - (Seasonal)		\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339	\$ 1.1339
27 COG amount		\$ 70.30	\$ 124.73	\$ 139.47	\$ 167.82	\$ 149.67	\$ 104.32	\$ 756.31
28								
29 LDAC		\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444	\$ 0.1444
30 LDAC amount		\$ 8.95	\$ 15.89	\$ 17.76	\$ 21.37	\$ 19.06	\$ 13.29	\$ 96.33
31								
32 Total Bill		\$ 129.56	\$ 217.96	\$ 241.90	\$ 287.94	\$ 258.47	\$ 184.81	\$ 1,320.63

34 November 1, 2020 - April 30, 2021  
 35 Residential Heating (R3)

		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
37 Typical Usage (Therms)		62	110	123	148	132	92	667
38								
40 Winter:	7/1/20 - 7/31/21							
41 Cust. Chg	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 93.00
42 Headblock	\$ 0.5678	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
43 Tailblock	\$ 0.5678	\$ 35.20	\$ 62.46	\$ 69.84	\$ 84.03	\$ 74.95	\$ 52.24	\$ 378.72
44 HB Threshold	-	\$ 34.53						
45								
46 Summer:	7/1/20 - 7/31/21							
47 Cust. Chg	\$ 15.50	\$ 15.50						
48 Headblock	\$ 0.5678	\$ 0.5632						
49 Tailblock	\$ 0.5678	\$ 0.5632						
50 HB Threshold	-							
51								
52 Total Base Rate Amount		\$ 50.70	\$ 77.96	\$ 85.34	\$ 99.53	\$ 90.45	\$ 67.74	\$ 471.72
53								
54 COG Rate - (Seasonal)		\$ 0.5571	\$ 0.5571	\$ 0.4664	\$ 0.4276	\$ 0.5156	\$ 0.6050	\$ 0.5100
55 COG amount		\$ 34.54	\$ 61.28	\$ 57.37	\$ 63.28	\$ 68.06	\$ 55.66	\$ 340.19
56								
57 LDAC		\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589	\$ 0.0589
58 LDAC amount		\$ 3.65	\$ 6.48	\$ 7.24	\$ 8.72	\$ 7.77	\$ 5.42	\$ 39.29
59								
60 Total Bill		\$ 88.90	\$ 145.72	\$ 149.95	\$ 171.54	\$ 166.28	\$ 128.82	\$ 851.20

62 DIFFERENCE:								
63 Total Bill		\$ 40.67	\$ 72.24	\$ 91.95	\$ 116.40	\$ 92.19	\$ 55.99	\$ 469.43
64 % Change		45.75%	49.57%	61.32%	67.86%	55.44%	43.47%	55.15%
65								
66 Base Rate		\$ (0.40)	\$ (0.62)	\$ (0.68)	\$ (0.79)	\$ (0.72)	\$ (0.53)	\$ (3.73)
67 % Change		-0.78%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%
68								
69 COG & LDAC		\$ 41.06	\$ 72.86	\$ 92.62	\$ 117.19	\$ 92.90	\$ 56.53	\$ 473.16
70 % Change		107.52%	107.52%	143.35%	162.76%	122.51%	92.55%	124.69%
check		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

May 1, 2022 - October 31, 2022

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
	51	28	16	14	14	21	144	811
\$	15.39	15.39	15.39	15.39	15.39	15.39	92.34	184.68
\$	-	-	-	-	-	-	-	-
\$	28.72	15.77	9.01	7.88	7.88	11.83	81.10	456.76
\$	44.11	31.16	24.40	23.27	23.27	27.22	173.44	641.44
\$	0.5587	0.5587	0.5587	0.5587	0.5587	0.5587	0.5587	1.0318
\$	28.49	15.64	8.94	7.82	7.82	11.73	80.45	836.76
\$	0.1444	0.1444	0.1444	0.1444	0.1444	0.1444	0.1444	0.1444
\$	7.37	4.04	2.31	2.02	2.02	3.03	20.80	117.13
\$	79.97	50.85	35.65	33.12	33.12	41.98	274.69	1,595.32

May 1, 2021 - October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
	51	28	16	14	14	21	144	811
\$	15.50	15.50	15.50	15.39	15.39	15.39	92.67	185.67
\$	28.96	15.90	9.08	7.88	7.88	11.83	81.54	460.26
\$	44.46	31.40	24.58	23.27	23.27	27.22	174.21	645.93
\$	0.3935	0.3935	0.3935	0.3935	0.3935	0.3935	0.3935	0.4893
\$	20.07	11.02	6.30	5.51	5.51	8.26	56.66	396.86
\$	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589
\$	3.00	1.65	0.94	0.82	0.82	1.24	8.48	47.77
\$	67.53	44.07	31.82	29.61	29.61	36.72	239.35	1,090.55

\$	12.44	6.78	3.83	3.51	3.51	5.27	35.34	504.77
\$	18.42%	15.39%	12.03%	11.86%	11.86%	14.34%	14.76%	46.29%
\$	(0.34)	(0.24)	(0.18)	-	-	-	(0.77)	(4.50)
\$	-0.78%	-0.76%	-0.75%	0.00%	0.00%	0.00%	-0.44%	-0.70%
\$	12.79	7.02	4.01	3.51	3.51	5.27	36.10	509.26
\$	55.42%	55.42%	55.42%	55.42%	55.42%	55.42%	55.42%	114.54%
\$	-	(0.00)	-	-	-	-	-	-

1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 2 Off Peak 2022 Summer Cost of Gas Filing  
 3 Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-41  
 4  
 5  
 6 November 1, 2021 - April 30, 2022  
 7 Commercial Rate (G-41)

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	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
10 Typical Usage (Therms)	89	277	504	457	331	297	1,955
11 Winter:	8/1/2021 - Current						
13 Cust. Chg	\$ 57.06	\$ 57.06	\$ 57.06	\$ 57.06	\$ 57.06	\$ 57.06	\$ 342.36
14 Headblock	\$ 0.4688	\$ 41.72	\$ 46.88	\$ 46.88	\$ 46.88	\$ 46.88	\$ 276.12
15 Tailblock	\$ 0.3149	\$ -	\$ 55.74	\$ 127.22	\$ 112.42	\$ 72.74	\$ 62.04
16 HB Threshold	100	\$41.93	\$46.88	\$46.88	\$46.88	\$46.88	\$46.88
17	8/1/2021 - Current						
18 Summer:	8/1/2021 - Current						
19 Cust. Chg	\$ 57.06						
20 Headblock	\$ 0.4688						
21 Tailblock	\$ 0.3149						
22 HB Threshold	20						
23							
24 Total Base Rate Amount	\$ 98.78	\$ 159.68	\$ 231.16	\$ 216.36	\$ 176.68	\$ 165.98	\$ 1,048.64
25							
26 COG Rate - (Seasonal)	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341
27 COG amount	\$ 100.93	\$ 314.15	\$ 571.59	\$ 518.28	\$ 375.39	\$ 336.83	\$ 2,217.17
28							
29 LDAC	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
30 LDAC amount	\$ 7.81	\$ 24.32	\$ 44.25	\$ 40.13	\$ 29.06	\$ 26.08	\$ 171.66
31							
32 Total Bill	\$ 207.53	\$ 498.15	\$ 847.00	\$ 774.77	\$ 581.13	\$ 528.88	\$ 3,437.46

34 November 1, 2020 - April 30, 2021  
 35 Commercial Rate (G-41)

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
38 Typical Usage (Therms)	89	277	504	457	331	297	1,955
39	7/1/20 - 7/31/21						
40 Winter:	8/1/2021 - Current						
41 Cust. Chg	\$ 57.46	\$ 57.06	\$ 57.46	\$ 57.46	\$ 57.46	\$ 57.46	\$ 344.76
42 Headblock	\$ 0.4711	\$ 0.4688	\$ 41.93	\$ 47.11	\$ 47.11	\$ 47.11	\$ 277.48
43 Tailblock	\$ 0.3165	\$ 0.3149	\$ -	\$ 56.02	\$ 127.87	\$ 112.99	\$ 73.11
44 HB Threshold	100	100					
45	7/1/20 - 7/31/21						
46 Summer:	8/1/2021 - Current						
47 Cust. Chg	\$ 57.46	\$ 57.06					
48 Headblock	\$ 0.4711	\$ 0.4688					
49 Tailblock	\$ 0.3165	\$ 0.3149					
50 HB Threshold	20	20					
51							
52 Total Base Rate Amount	\$ 99.39	\$ 160.59	\$ 232.44	\$ 217.56	\$ 177.68	\$ 166.92	\$ 1,054.58
53							
54 COG Rate - (Seasonal)	\$ 0.5552	\$ 0.5552	\$ 0.4645	\$ 0.4257	\$ 0.5137	\$ 0.6031	\$ 0.5018
55 COG amount	\$ 49.41	\$ 153.79	\$ 234.11	\$ 194.54	\$ 170.03	\$ 179.12	\$ 981.01
56							
57 LDAC	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
58 LDAC amount	\$ 4.94	\$ 15.37	\$ 27.97	\$ 25.36	\$ 18.37	\$ 16.48	\$ 108.50
59							
60 Total Bill	\$ 153.74	\$ 329.75	\$ 494.52	\$ 437.47	\$ 366.09	\$ 362.52	\$ 2,144.09

62 DIFFERENCE:

63 Total Bill	\$ 53.79	\$ 168.39	\$ 352.48	\$ 337.30	\$ 215.05	\$ 166.36	\$ 1,293.37
64 % Change	34.99%	51.07%	71.28%	77.10%	58.74%	45.89%	60.32%
65							
66 Base Rate	\$ (0.60)	\$ (0.91)	\$ (1.28)	\$ (1.20)	\$ (1.00)	\$ (0.95)	\$ (5.94)
67 % Change	-0.61%	-0.57%	-0.55%	-0.55%	-0.56%	-0.57%	-0.56%
68							
69 COG & LDAC	\$ 54.40	\$ 169.30	\$ 353.76	\$ 338.50	\$ 216.05	\$ 167.30	\$ 1,299.31
70 % Change	100.08%	134.98%	134.98%	153.93%	114.67%	85.53%	119.26%
check	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

May 1, 2022 - October 31, 2022

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
	153	39	26	34	25	29	306	2,261
\$	57.06	57.06	57.06	57.06	57.06	57.06	342.36	684.72
\$	9.38	9.38	9.38	9.38	9.38	9.38	56.26	332.38
\$	41.88	5.98	1.89	4.41	1.57	2.83	58.57	488.72
\$	108.32	72.42	68.33	70.84	68.01	69.27	457.19	1,505.82
\$	0.5593	0.5593	0.5593	0.5593	0.5593	0.5593	0.5593	1.0563
\$	85.57	21.81	14.54	19.02	13.98	16.22	171.15	2,388.31
\$	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878	0.0878
\$	13.43	3.42	2.28	2.99	2.20	2.55	26.87	198.53
\$	207.33	97.66	85.15	92.85	84.19	88.04	655.20	4,092.67

May 1, 2021 - October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
	153	39	26	34	25	29	306	2,261
\$	57.46	57.46	57.46	57.06	57.06	57.06	343.56	688.32
\$	9.42	9.42	9.42	9.38	9.38	9.38	56.39	333.87
\$	42.09	6.01	1.90	4.41	1.57	2.83	58.82	491.16
\$	108.98	72.90	68.78	70.84	68.01	69.27	458.78	1,513.36
\$	0.3886	0.3886	0.3886	0.3886	0.3886	0.3886	0.3886	0.4865
\$	59.46	15.16	10.10	13.21	9.72	11.27	118.91	1,099.92
\$	0.0555	0.0555	0.0555	0.0555	0.0555	0.0555	0.0555	0.0555
\$	8.49	2.16	1.44	1.89	1.39	1.61	16.98	125.49
\$	176.92	90.22	80.33	85.94	79.11	82.15	594.67	2,738.76

\$	30.40	7.44	4.82	6.90	5.08	5.89	60.53	1,353.90
\$	17.18%	8.25%	6.00%	8.03%	6.42%	7.17%	10.18%	49.43%
\$	(0.66)	(0.48)	(0.46)	-	-	-	(1.59)	(7.53)
\$	-0.60%	-0.65%	-0.66%	0.00%	0.00%	0.00%	-0.35%	-0.50%
\$	31.06	7.92	5.28	6.90	5.08	5.89	62.12	1,361.43
\$	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	111.10%
\$	-	-	-	0.00	0.00	(0.00)	(0.00)	-

1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 2 Off Peak 2022 Summer Cost of Gas Filing  
 4 Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-42  
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 7 November 1, 2021 - April 30, 2022  
 8 C&I High Winter Use Medium G-42

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May 1, 2022 - October 31, 2022

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
11 Typical Usage (Therms)	830	2,189	3,708	3,406	2,603	2,395	15,131
12							
13 Winter:	8/1/2021 - Current						
14 Cust. Chg	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14
15 Headblock	\$ 0.4261	\$ 353.66	\$ 426.10	\$ 426.10	\$ 426.10	\$ 426.10	\$ 2,484.16
16 Tailblock	\$ 0.2839	\$ -	\$ 337.56	\$ 768.80	\$ 683.06	\$ 455.09	\$ 2,640.55
17 HB Threshold	1,000						
18							
19 Summer:	8/1/2021 - Current						
20 Cust. Chg	\$ 171.19						
21 Headblock	\$ 0.4261						
22 Tailblock	\$ 0.2839						
23 HB Threshold	400						
24							
25 Total Base Rate Amount	\$ 524.85	\$ 934.85	\$ 1,366.09	\$ 1,280.35	\$ 1,052.38	\$ 993.33	\$ 6,151.86
26							
27 COG Rate - (Seasonal)	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341	\$ 1.1341
28 COG amount	\$ 941.30	\$ 2,482.54	\$ 4,205.24	\$ 3,862.74	\$ 2,952.06	\$ 2,716.17	\$ 17,160.07
29							
30 LDAC	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
31 LDAC amount	\$ 72.88	\$ 192.21	\$ 325.59	\$ 299.07	\$ 228.56	\$ 210.30	\$ 1,328.61
32							
33 Total Bill	\$ 1,539.04	\$ 3,609.60	\$ 5,896.92	\$ 5,442.17	\$ 4,233.01	\$ 3,919.80	\$ 24,640.53
34							

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
	1,319	484	285	247	269	340	2,944	18,075
	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14	\$ 2,054.28
	\$ 170.44	\$ 170.44	\$ 121.44	\$ 105.25	\$ 114.62	\$ 144.87	\$ 827.06	\$ 3,311.22
	\$ 260.90	\$ 23.85	\$ -	\$ -	\$ -	\$ -	\$ 284.75	\$ 2,925.31
	\$ 602.53	\$ 365.48	\$ 292.63	\$ 276.44	\$ 285.81	\$ 316.06	\$ 2,138.95	\$ 8,290.81
	\$ 0.5593	\$ 0.5593	\$ 0.5593	\$ 0.5593	\$ 0.5593	\$ 0.5593	\$ 0.5593	\$ 1.0405
	\$ 737.72	\$ 270.70	\$ 159.40	\$ 138.15	\$ 150.45	\$ 190.16	\$ 1,646.58	\$ 18,806.65
	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
	\$ 115.82	\$ 42.50	\$ 25.02	\$ 21.69	\$ 23.62	\$ 29.85	\$ 258.50	\$ 1,587.11
	\$ 1,456.07	\$ 678.68	\$ 477.05	\$ 436.27	\$ 459.88	\$ 536.08	\$ 4,044.03	\$ 28,684.57

May 1, 2021 - October 31, 2021

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
37 Typical Usage (Therms)	830	2,189	3,708	3,406	2,603	2,395	15,131
38							
39							
40							
41 Winter:	7/1/20 - 7/31/21	8/1/2021 - Current					
42 Cust. Chg	\$ 172.39	\$ 171.19	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 1,034.34
43 Headblock	\$ 0.4284	\$ 0.4261	\$ 428.40	\$ 428.40	\$ 428.40	\$ 428.40	\$ 2,497.57
44 Tailblock	\$ 0.2855	\$ 0.2839	\$ -	\$ 339.46	\$ 773.13	\$ 686.91	\$ 457.66
45 HB Threshold	1,000	1,000					
46							
47 Summer:	7/1/20 - 7/31/21	8/1/2021 - Current					
48 Cust. Chg	\$ 172.39	\$ 171.19					
49 Headblock	\$ 0.4284	\$ 0.4261					
50 Tailblock	\$ 0.2855	\$ 0.2839					
51 HB Threshold	400	400					
52							
53 Total Base Rate Amount	\$ 527.96	\$ 940.25	\$ 1,373.92	\$ 1,287.70	\$ 1,058.45	\$ 999.06	\$ 6,187.35
54							
55 COG Rate - (Seasonal)	\$ 0.5552	\$ 0.5552	\$ 0.4645	\$ 0.4257	\$ 0.5137	\$ 0.6031	\$ 0.5043
56 COG amount	\$ 460.82	\$ 1,215.33	\$ 1,722.37	\$ 1,449.93	\$ 1,337.16	\$ 1,444.42	\$ 7,630.03
57							
58 LDAC	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
59 LDAC amount	\$ 46.07	\$ 121.49	\$ 205.79	\$ 189.03	\$ 144.47	\$ 132.92	\$ 839.77
60							
61 Total Bill	\$ 1,034.84	\$ 2,277.07	\$ 3,302.08	\$ 2,926.67	\$ 2,540.07	\$ 2,576.41	\$ 14,657.15
62							

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
	1,319	484	285	247	269	340	2,944	18,075
	\$ 172.39	\$ 172.39	\$ 172.39	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,030.74	\$ 2,065.08
	\$ 171.36	\$ 171.36	\$ 122.09	\$ 105.25	\$ 114.62	\$ 144.87	\$ 829.56	\$ 3,327.13
	\$ 262.37	\$ 23.98	\$ -	\$ -	\$ -	\$ -	\$ 286.36	\$ 2,941.79
	\$ 606.12	\$ 367.73	\$ 294.48	\$ 276.44	\$ 285.81	\$ 316.06	\$ 2,146.65	\$ 8,334.00
	\$ 0.3886	\$ 0.3886	\$ 0.3886	\$ 0.3886	\$ 0.3886	\$ 0.3886	\$ 0.3886	\$ 0.4854
	\$ 512.96	\$ 188.08	\$ 110.75	\$ 95.98	\$ 104.53	\$ 132.12	\$ 1,144.04	\$ 8,774.07
	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
	\$ 73.20	\$ 26.86	\$ 15.82	\$ 13.71	\$ 14.93	\$ 18.87	\$ 163.39	\$ 1,003.16
	\$ 1,191.89	\$ 582.68	\$ 421.05	\$ 386.13	\$ 405.27	\$ 467.06	\$ 3,454.08	\$ 18,111.24

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
63 DIFFERENCE:							
64 Total Bill	\$ 504.19	\$ 1,332.53	\$ 2,594.84	\$ 2,515.50	\$ 1,692.93	\$ 1,343.39	\$ 9,983.38
65 % Change	48.72%	58.52%	78.58%	85.95%	66.65%	52.14%	68.11%
66							
67 Base Rate	\$ (3.11)	\$ (5.40)	\$ (7.83)	\$ (7.35)	\$ (6.06)	\$ (5.73)	\$ (35.49)
68 % Change	-0.59%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%
69							
70 COG & LDAC	\$ 507.30	\$ 1,337.93	\$ 2,602.67	\$ 2,522.85	\$ 1,699.00	\$ 1,349.12	\$ 10,018.87
71 % Change	100.08%	100.08%	134.98%	153.93%	114.67%	85.53%	118.29%
check	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
	\$ 264.18	\$ 96.00	\$ 56.00	\$ 50.14	\$ 54.61	\$ 69.02	\$ 589.95	\$ 10,573.33
	22.16%	16.48%	13.30%	12.99%	13.47%	14.78%	17.08%	58.38%
	\$ (3.59)	\$ (2.25)	\$ (1.86)	\$ -	\$ -	\$ -	\$ (7.70)	\$ (43.19)
	-0.59%	-0.61%	-0.63%	0.00%	0.00%	0.00%	-0.36%	-0.52%
	\$ 267.77	\$ 98.26	\$ 57.86	\$ 50.14	\$ 54.61	\$ 69.02	\$ 597.65	\$ 10,616.52
	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	108.58%
	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

1 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty  
 2 Off Peak 2022 Summer Cost of Gas Filing  
 4 Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-52  
 5  
 6  
 7 November 1, 2021 - April 30, 2022  
 8 Commercial Rate (G-52)

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	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
11 Typical Usage (Therms)	1,352	1,866	2,284	2,160	1,886	1,760	11,308
12							
13 Winter:							
14 Cust. Chg	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14
15 Headblock	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 0.2428	\$ 1,456.80
16 Tailblock	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 858.30
17 HB Threshold	1,000						
18							
19 Summer:							
20 Cust. Chg	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14
21 Headblock	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 1,031.39
22 Tailblock	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 73.20
23 HB Threshold	1,000						
24							
25 Total Base Rate Amount	\$ 470.91	\$ 554.02	\$ 621.61	\$ 601.56	\$ 557.26	\$ 536.88	\$ 3,342.24
26							
27 COG Rate - (Seasonal)	\$ 1.1324	\$ 1.1324	\$ 1.1324	\$ 1.1324	\$ 1.1324	\$ 1.1324	\$ 1.1324
28 COG amount	\$ 1,531.00	\$ 2,113.06	\$ 2,586.40	\$ 2,445.98	\$ 2,135.71	\$ 1,993.02	\$ 12,805.18
29							
30 LDAC	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
31 LDAC amount	\$ 118.72	\$ 163.85	\$ 200.55	\$ 189.66	\$ 165.60	\$ 154.54	\$ 992.92
32							
33 Total Bill	\$ 2,120.63	\$ 2,830.93	\$ 3,408.57	\$ 3,237.21	\$ 2,858.57	\$ 2,684.45	\$ 17,140.34

35 November 1, 2020 - April 30, 2021  
 36 Commercial Rate (G-52)

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
37							
38							
39 Typical Usage (Therms)	1,352	1,866	2,284	2,160	1,886	1,760	11,308
40							
41 Winter:							
42 Cust. Chg	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 1,034.34
43 Headblock	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 0.2439	\$ 1,463.40
44 Tailblock	\$ 0.1624	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 0.1617	\$ 862.02
45 HB Threshold	1,000	1,000					
46							
47 Summer:							
48 Cust. Chg	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 172.39	\$ 1,034.34
49 Headblock	\$ 0.1767	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 0.1749	\$ 1,036.79
50 Tailblock	\$ 0.1004	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 0.1000	\$ 73.46
51 HB Threshold	1,000	1,000					
52							
53 Total Base Rate Amount	\$ 473.45	\$ 556.93	\$ 624.81	\$ 604.67	\$ 560.18	\$ 539.71	\$ 3,359.76
54							
55 COG Rate - (Seasonal)	\$ 0.5660	\$ 0.5660	\$ 0.4753	\$ 0.4365	\$ 0.5245	\$ 0.6139	\$ 0.5235
56 COG amount	\$ 765.23	\$ 1,056.16	\$ 1,085.59	\$ 942.84	\$ 989.21	\$ 1,080.46	\$ 5,919.48
57							
58 LDAC	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
59 LDAC amount	\$ 75.04	\$ 103.56	\$ 126.76	\$ 119.88	\$ 104.67	\$ 97.68	\$ 627.59
60							
61 Total Bill	\$ 1,313.72	\$ 1,716.65	\$ 1,837.16	\$ 1,667.39	\$ 1,654.06	\$ 1,717.86	\$ 9,906.84

62 DIFFERENCE:

63 Total Bill	\$ 806.91	\$ 1,114.28	\$ 1,571.41	\$ 1,569.82	\$ 1,204.51	\$ 966.69	\$ 7,233.51
64 % Change	61.42%	64.91%	85.53%	94.15%	72.82%	56.27%	73.02%
65							
66							
67 Base Rate	\$ (2.55)	\$ (2.91)	\$ (3.20)	\$ (3.11)	\$ (2.92)	\$ (2.83)	\$ (17.52)
68 % Change	-0.54%	-0.52%	-0.51%	-0.51%	-0.52%	-0.52%	-0.52%
69							
70 COG & LDAC	\$ 809.45	\$ 1,117.19	\$ 1,574.61	\$ 1,572.93	\$ 1,207.43	\$ 969.42	\$ 7,251.02
71 % Change	96.33%	96.33%	129.88%	148.81%	110.38%	82.28%	110.75%
check	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

May 1, 2022 - October 31, 2022

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,027.14	\$ 2,054.28
\$ 174.90	\$ 174.90	\$ 174.90	\$ 174.90	\$ 174.90	\$ 174.90	\$ 156.89	\$ 1,031.39	\$ 2,488.19
\$ 49.70	\$ 12.80	\$ 3.20	\$ 2.50	\$ 5.00	\$ -	\$ -	\$ 73.20	\$ 931.50
\$ 395.79	\$ 358.89	\$ 349.29	\$ 348.59	\$ 351.09	\$ 328.08	\$ -	\$ 2,131.73	\$ 5,473.97
\$ 0.5580	\$ 0.5580	\$ 0.5580	\$ 0.5580	\$ 0.5580	\$ 0.5580	\$ 0.5580	\$ 0.5580	\$ 0.9201
\$ 835.33	\$ 629.42	\$ 575.86	\$ 571.95	\$ 585.90	\$ 500.53	\$ -	\$ 3,698.98	\$ 16,504.16
\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878	\$ 0.0878
\$ 131.45	\$ 99.05	\$ 90.62	\$ 90.00	\$ 92.20	\$ 78.76	\$ -	\$ 582.07	\$ 1,574.99
\$ 1,362.66	\$ 1,087.36	\$ 1,015.76	\$ 1,010.54	\$ 1,029.19	\$ 907.36	\$ -	\$ 6,412.78	\$ 23,553.12

May 1, 2021 - October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
\$ 172.39	\$ 172.39	\$ 172.39	\$ 171.19	\$ 171.19	\$ 171.19	\$ 171.19	\$ 1,030.74	\$ 2,065.08
\$ 176.70	\$ 176.70	\$ 176.70	\$ 174.90	\$ 174.90	\$ 156.89	\$ -	\$ 1,036.79	\$ 2,509.19
\$ 49.90	\$ 12.85	\$ 3.21	\$ 2.50	\$ 5.00	\$ -	\$ -	\$ 73.46	\$ 935.48
\$ 398.99	\$ 361.94	\$ 352.30	\$ 348.59	\$ 351.09	\$ 328.08	\$ -	\$ 2,140.99	\$ 5,500.75
\$ 0.3999	\$ 0.3999	\$ 0.3999	\$ 0.3999	\$ 0.3999	\$ 0.3999	\$ 0.3999	\$ 0.3999	\$ 0.4778
\$ 598.65	\$ 451.09	\$ 412.70	\$ 409.90	\$ 419.90	\$ 358.71	\$ -	\$ 2,650.94	\$ 8,570.42
\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555	\$ 0.0555
\$ 83.08	\$ 62.60	\$ 57.28	\$ 56.89	\$ 58.28	\$ 49.78	\$ -	\$ 367.91	\$ 995.50
\$ 1,080.72	\$ 875.63	\$ 822.28	\$ 815.38	\$ 829.26	\$ 736.57	\$ -	\$ 5,159.83	\$ 15,066.67

\$ 281.84	\$ 211.73	\$ 193.49	\$ 195.17	\$ 199.93	\$ 170.80	\$ -	\$ 1,252.95	\$ 8,486.45
26.08%	24.18%	23.53%	23.94%	24.11%	23.19%	\$ -	24.28%	56.33%
\$ (3.20)	\$ (3.05)	\$ (3.01)	\$ -	\$ -	\$ -	\$ -	\$ (9.26)	\$ (26.78)
-0.80%	-0.84%	-0.86%	0.00%	0.00%	0.00%	\$ -	-0.43%	-0.49%
\$ 285.04	\$ 214.78	\$ 196.50	\$ 195.17	\$ 199.93	\$ 170.80	\$ -	\$ 1,262.21	\$ 8,513.23
41.81%	41.81%	41.81%	41.81%	41.81%	41.81%	\$ -	41.81%	89.00%

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

2 Off Peak 2022 Summer Cost of Gas Filing

3 Residential Heating

	Summer 2021	Summer 2022
4		
5 Customer Charge	\$ 15.50	\$ 15.39
6 First 20 Therms	\$ 0.5678	\$ 0.5632
7 Excess 20 Therms	\$ 0.5678	\$ 0.5632
8 LDAC	\$ 0.0589	\$ 0.1444
9 COG	\$ 0.5587	\$ 0.5587
10 Total Adjust	\$ 0.6176	\$ 0.7031

	Summer 2021 COG @	Summer 2022 Cog @
11		
12		
13		
14		
15	\$ 0.6176	\$ 0.7031
16		
17		
18 Cooking alone	5 \$ 21.43	\$ 21.72
19		
20	10 \$ 27.35	\$ 28.05
21		
22	20 \$ 39.21	\$ 40.72
23		
24 Water Heating alone	30 \$ 51.06	\$ 53.38
25		
26	45 \$ 68.84	\$ 72.37
27		
28	50 \$ 74.77	\$ 78.71
29		
30 Heating Alone	80 \$ 104.41	\$ 110.36
31		
32	125 \$ 173.16	\$ 183.81
33		
34	150 \$ 193.31	\$ 205.34
35		
36	200 \$ 252.58	\$ 268.65
37		

Total	Base Rate		COG		LDAC		
\$ Impact	% Impact	\$ Impact	% Impact	\$ Impact	% Impact	\$ Impact	% Impact
\$ 0.09	14%						
\$ 0.29	1%	\$ (0.13)	-1%	\$ -	0%	\$ 0.43	2%
\$ 0.70	3%	\$ (0.16)	-1%	\$ -	0%	\$ 0.86	3%
\$ 1.51	4%	\$ (0.20)	-1%	\$ -	0%	\$ 1.71	4%
\$ 2.32	5%	\$ (0.25)	0%	\$ -	0%	\$ 2.57	5%
\$ 3.53	5%	\$ (0.32)	0%	\$ -	0%	\$ 3.85	6%
\$ 3.94	5%	\$ (0.34)	0%	\$ -	0%	\$ 4.28	6%
\$ 5.96	6%	\$ (0.45)	0%	\$ -	0%	\$ 6.41	6%
\$ 10.65	6%	\$ (0.72)	0%	\$ -	0%	\$ 11.37	7%
\$ 12.03	6%	\$ (0.80)	0%	\$ -	0%	\$ 12.83	7%
\$ 16.07	6%	\$ (1.03)	0%	\$ -	0%	\$ 17.10	7%

**2022 Summer Cost of Gas Filing**  
**Capacity Assignment Calculations 2020-2021**  
**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 Residential 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, Dekatherm	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	659	715	0.4%	103	613
2	RATE R-3-Resi Htg	66,114	72,399	42.2%	3,617	68,783
3	RATE G-41 (T)	28,689	31,499	18.4%	750	30,749
4	RATE G-51 (S)	2,361	2,534	1.5%	641	1,893
5	RATE G-42 (V)	36,728	40,301	23.5%	1,198	39,104
6	RATE G-52	5,125	5,490	3.2%	1,498	3,992
7	RATE G-43	9,793	10,710	6.2%	678	10,031
8	RATE G-53	5,922	6,346	3.7%	1,715	4,631
9	RATE G-54	1,495	1,608	0.9%	378	1,230
10						
11	Total	156,887	171,602	100.0%	10,577	161,025
12						-
13	Residential Total	66,773	73,115	<b>42.607%</b>	3,719	69,396
14	LLF Total	75,211	82,510	<b>48.083%</b>	2,626	79,885
15	HLF Total	14,903	15,977	<b>9.310%</b>	4,232	11,745
16	Total	156,887	171,602	100.0%	10,577	161,025
17						
18	C&I Breakdown					
19	LLF Total				2,626	79,885
20	HLF Total				4,232	11,745
21	Total				6,858	91,630
22						
23	C&I Breakdown Percentage					
24	LLF Total				38.291%	87.182%
25	HLF Total				61.709%	12.818%
26	Total				<b>100.0%</b>	<b>100.0%</b>
27						
28		Capacity Cost	MDQ, Dt	\$/Dt-Mo.		
29	Pipeline	\$16,344,325	119,718	\$11.3770		
30	Storage	\$4,121,310	28,115	\$12.2156		
31						
32	Peaking	\$4,119,000				
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)	\$0				
34	Subtotal Peaking Costs	\$4,119,000	23,769	\$14.4412		
35	Total	\$24,584,635	171,602	\$11.9388		
36						
37		Capacity Cost	MDQ, Dt	\$/Dt-Mo.		
38	Pipeline - Baseload	1,443,958	10,577	\$11.3770		
39	Pipeline - Remaining	14,900,367	109,141	\$11.3770		
40	Storage	4,121,310	28,115	\$12.2156		
41	Peaking	4,119,000	23,769	\$14.4412		
42	Total	24,584,635	171,602	\$11.9388		
43						
44						
45	Residential Allocation	Capacity Cost	MDQ, Dt	\$/Dt-Mo.		
46	Pipeline - Base	Line 38 * Line 13 Col C	615,228	4,506	\$11.3770	
47	Pipeline - Remaining	Line 39 * Line 13 Col C	6,348,623	46,502	\$11.3770	
48	Storage	Line 40 * Line 13 Col C	1,755,962	11,979	\$12.2156	
49	Peaking	Line 41 * Line 13 Col C	1,754,952	10,127	\$14.4412	
50	Total	<b>42.607%</b>	10,474,751	73,114	\$11.9388	
51						

**2022 Summer Cost of Gas Filing**  
**Capacity Assignment Calculations 2020-2021**  
**Derivation of Class Assignments and Weightings**

				Capacity Cost	MDQ, Dt	\$/Dt-Mo.	<b>Ratios for COG</b>
59	C&I Allocation						
60	Pipeline - Base	Line 38 - Line 46		828,730	6,070	\$11.3770	<b>1.0000</b>
61	Pipeline - Remaining	Line 39 - Line 47		8,551,745	62,640	\$11.3769	
62	Storage	Line 40 - Line 48		2,365,348	16,136	\$12.2157	
63	Peaking	Line 41 - Line 49		<u>2,364,048</u>	<u>13,642</u>	<u>\$14.4410</u>	
64	Total		<b>57.393%</b>	14,109,870	98,488	\$11.9388	
65							
66							
67	LLF - C&I Allocation						
68	Pipeline - Base	Line 60 * Line 24 Col E		317,329	2,324	\$11.3787	<b>1.0017</b> (Line 72 / Line 64)
69	Pipeline - Remaining	Line 61 * Line 24 Col F		7,455,589	54,610	\$11.3770	
70	Storage	Line 62 * Line 24 Col F		2,062,160	14,068	\$12.2154	
71	Peaking	Line 63 * Line 24 Col F		<u>2,061,026</u>	<u>11,893</u>	<u>\$14.4415</u>	
72	Total		<b>48.3884%</b>	11,896,104	82,895	\$11.9590	
73			38.291%	84%			
74							
75	HLF - C&I Allocation						
76	Pipeline - Base	Line 60 - Line 68		511,401	3,746	\$11.3766	<b>0.9910</b> (Line 80 / Line 64)
77	Pipeline - Remaining	Line 61 - Line 69		1,096,156	8,030	\$11.3756	
78	Storage	Line 62 - Line 70		303,188	2,068	\$12.2174	
79	Peaking	Line 63 - Line 71		<u>303,022</u>	<u>1,749</u>	<u>\$14.4379</u>	
80	Total		<b>9.0047%</b>	2,213,767	15,593	\$11.8310	
81							
82							
83	Unit Cost			Residential	LLF C&I	HLF C&I	
84							
85	Pipeline			\$ 11.3770	\$ 11.3770	\$ 11.3770	
86	Storage			\$ 12.2156	\$ 12.2156	\$ 12.2156	
87	Peaking			\$ -	\$ -	\$ -	
88	Total			\$ 11.9388	\$ 11.9590	\$ 11.8310	
89							
90							
91	Load Makeup			Residential	LLF C&I	HLF C&I	
92							
93	Pipeline			69.77%	<b>68.68%</b>	<b>75.52%</b>	
94	Storage			16.38%	<b>16.97%</b>	<b>13.26%</b>	
95	Peaking			13.85%	<b>14.35%</b>	<b>11.22%</b>	
96	Total			100.00%	<b>100.00%</b>	<b>100.00%</b>	
97							
98							
99	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
100							
101	Pipeline			42.61%	47.56%	9.84%	100.00%
102	Storage			42.61%	50.04%	7.36%	100.00%
103	Peaking			42.61%	50.04%	7.36%	100.00%

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

2

3 **2022 Summer Cost of Gas Filing**

4 **Correction Factor Calculation**

5

6

7

8 Data Source: Schedule 10B

9

10

11 G-41

12 G-42

13 G-43

14 High Winter Use

15

16 G-51

17 G-52

18 G-53

19 G-54

21 Low Winter Use

22

23 **Gross Total**

24

25

26 Total Sales

27 Low Winter Use

28 Summer Ratio for Low Winter Use

29 High Winter Use

30 Summer Ratio for High Winter Use

31

32 Correction Factor =

33 Correction Factor =

34

35

36 **Allocation Calculation for Miscellaneous Overhead**

37

38 Projected Winter Sales Volume

39 Projected Annual Sales Volume

40 Percentage of Winter Sales to Annual Sales

	d	e	f	g	h	i	Total Sales
	May	June	July	Aug	Sep	Oct	
G-41	735,770	276,570	203,130	205,140	361,450	944,100	2,726,160
G-42	689,280	298,640	221,790	230,200	400,180	866,050	2,706,140
G-43	179,740	73,660	58,680	59,440	100,920	204,000	676,440
High Winter Use	1,604,790	648,870	483,600	494,780	862,550	2,014,150	6,108,740
G-51	201,180	178,670	180,600	181,250	187,340	243,850	1,172,890
G-52	222,310	202,670	214,620	214,540	214,530	259,620	1,328,290
G-53	308,310	268,810	269,370	265,280	270,620	322,980	1,705,370
G-54	15,120	18,750	22,560	24,140	22,080	24,180	126,830
Low Winter Use	746,920	668,900	687,150	685,210	694,570	850,630	4,333,380
<b>Gross Total</b>	<b>2,351,710</b>	<b>1,317,770</b>	<b>1,170,750</b>	<b>1,179,990</b>	<b>1,557,120</b>	<b>2,864,780</b>	<b>10,442,120</b>

10,442,120

4,333,380

**0.9910 Schedule 10A p 2, In 80**

6,108,740

**1.0017 Schedule 10A p 2, In 72**

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

**100.2748%**

11/1/21- 4/30/22

91,676,680 Sch.10B, In 23

11/1/21 - 10/31/22

115,042,810 Sch.10B, In 23

79.69%



1 Liberty Utilities (EnergyNorth Natural Gas) Corp.  
2 d/b/a Liberty Utilities  
3 Off Peak 2022 Summer Cost of Gas Filing  
4 2022 Summer Cost of Gas Filing

Dry Therms															
	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Subtotal PK 21-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Subtotal OP 22	Total
7 Firm Sales															
8															
9 R-1	68,340	87,950	100,820	86,060	85,740	64,450	493,360	51,360	38,850	33,950	34,160	38,040	51,620	247,980	741,340
10 R-3	6,259,770	9,415,520	10,967,410	9,270,440	7,794,900	4,711,810	48,419,850	2,667,890	1,294,670	1,005,090	1,028,340	1,719,640	4,100,280	11,815,910	60,235,760
11 R-4	454,380	670,430	779,980	661,890	559,780	360,860	3,487,320	203,890	100,540	76,380	75,540	119,390	284,380	860,120	4,347,440
12 Total Residential.	6,782,490	10,173,900	11,848,210	10,018,390	8,440,420	5,137,120	52,400,530	2,923,140	1,434,060	1,115,420	1,138,040	1,877,070	4,436,280	12,924,010	65,324,540
13															
14 G-41	1,993,710	3,256,330	3,928,840	3,309,510	2,686,900	1,577,780	16,753,070	735,770	276,570	203,130	205,140	361,450	944,100	2,726,160	19,479,230
15 G-42	1,614,090	2,539,420	3,002,840	2,538,570	2,173,870	1,204,090	13,072,880	689,280	298,640	221,790	230,200	400,180	866,050	2,706,140	15,779,020
16 G-43	351,200	532,700	648,170	538,750	488,120	288,000	2,846,940	179,740	73,660	58,680	59,440	100,920	204,000	676,440	3,523,380
17 G-51	269,320	351,810	388,860	324,250	336,580	212,980	1,883,800	201,180	178,670	180,600	181,250	187,340	243,850	1,172,890	3,056,690
18 G-52	317,340	408,180	446,890	364,850	374,660	242,020	2,153,940	222,310	202,670	214,620	214,540	214,530	259,620	1,328,290	3,482,230
19 G-53	360,520	440,110	480,670	393,940	408,840	343,630	2,427,710	308,310	268,810	269,370	265,280	270,620	322,980	1,705,370	4,133,080
20 G-54	35,050	39,900	17,030	15,360	16,670	13,800	137,810	15,120	18,750	22,560	24,140	22,080	24,180	126,830	264,640
21 Total C/I	4,941,230	7,568,450	8,913,300	7,485,230	6,485,640	3,882,300	39,276,150	2,351,710	1,317,770	1,170,750	1,179,990	1,557,120	2,864,780	10,442,120	49,718,270
22															
23 Sales Volume	11,723,720	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	91,676,680	5,274,850	2,751,830	2,286,170	2,318,030	3,434,190	7,301,060	23,366,130	115,042,810
24															
25 Transportation Sales															
26															
27 G-41	574,020	867,030	1,039,180	856,480	763,130	450,870	4,550,710	261,840	140,990	106,460	95,760	156,800	326,870	1,088,720	5,639,430
28 G-42	1,968,530	2,914,590	3,391,170	2,830,750	2,515,270	1,523,590	15,143,900	906,300	496,460	395,030	398,340	659,800	1,261,210	4,117,140	19,261,040
29 G-43	771,060	1,044,290	1,235,960	1,039,110	971,040	538,960	5,600,420	365,460	237,030	213,480	240,670	339,080	530,620	1,926,340	7,526,760
30 G-51	84,590	105,400	113,700	94,860	99,260	81,810	579,620	77,390	64,770	61,300	61,170	63,740	76,000	404,370	983,990
31 G-52	497,790	617,920	679,580	565,210	579,610	430,990	3,371,100	389,470	360,850	367,700	363,660	373,650	442,840	2,298,170	5,669,270
32 G-53	855,560	987,600	1,082,920	916,680	934,740	840,440	5,617,940	724,650	621,190	623,930	659,410	675,470	791,330	4,095,980	9,713,920
33 G-54	1,585,390	1,292,050	1,269,400	1,054,210	1,161,320	1,357,730	7,720,100	1,561,020	1,567,000	1,631,330	1,739,250	1,682,640	1,755,260	9,936,500	17,656,600
34															
35 Total Trans. Sales	6,336,940	7,828,880	8,811,910	7,357,300	7,024,370	5,224,390	42,583,790	4,286,130	3,488,290	3,399,230	3,558,260	3,951,180	5,184,130	23,867,220	66,451,010
36															
37 Total All Sales	18,060,660	25,571,230	29,573,420	24,860,920	21,950,430	14,243,810	134,260,470	9,560,980	6,240,120	5,685,400	5,876,290	7,385,370	12,485,190	47,233,350	181,493,820

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

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3 **Off Peak 2022 Summer Cost of Gas Filing**

4 **Normal and Design Year Volumes**

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7 **Volumes (Therms) Normal Year**

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9 **For the Months of May 22 -October 22**

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	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Off Peak May - Oct
Pipeline Gas:							
Dawn Supply	739,535	95,658	-	-	206,295	636,518	1,678,006
Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
TGP Supply (Gulf)	13,120	-	-	-	-	384,326	397,446
Dracut Supply 1 - Baseload	-	-	-	-	-	-	0
Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
Dracut Supply 3 - Swing	-	-	-	-	-	-	-
Constellation Combo	-	-	-	-	-	-	0
LNG Truck	44,883	18,131	-	-	55,566	20,602	139,181
Propane Truck	79,409	71,899	69,472	69,279	73,449	81,696	445,204
PNGTS	205,081	146,300	119,612	125,908	176,916	218,093	991,910
Portland Natural Gas	152,602	3,126	-	-	2,555	574,003	732,286
TGP Supply (Z4)	5,386,659	4,708,479	4,708,982	4,696,535	4,819,522	5,546,088	29,866,267
	7,289,702	5,584,403	5,440,551	5,437,523	5,925,726	8,585,177	38,263,081
Storage Gas:							
	-	-	-	-	-	-	0
Produced Gas:							
LNG Vapor	20,025	18,131	17,519	17,470	18,522	20,602	112,269
Propane	-	-	-	-	-	-	0
	20,025	18,131	17,519	17,470	18,522	20,602	112,269
Less - Gas Refills:							
LNG Truck	(44,883)	(18,131)	-	-	(55,566)	(20,602)	(139,181)
Propane	(79,409)	(71,899)	(69,472)	(69,279)	(73,449)	(81,696)	(445,204)
TGP Storage Refill	(2,188,222)	(2,766,568)	(3,120,796)	(3,057,929)	(2,444,250)	(1,262,380)	(14,840,145)
	(2,312,514)	(2,856,598)	(3,190,268)	(3,127,208)	(2,573,265)	(1,364,677)	(15,424,530)
Total Sendout Volumes	4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.

Updated Schedule 11B

2

Page 1 of 1

3 Off Peak 2022 Summer Cost of Gas Filing

44 Normal and Design Year Volumes

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47 Volumes (Therms)

Design Year

48

49 For the Months of May 22 -October 22

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53 Pipeline Gas:

54 Dawn Supply

55 Niagara Supply

56 TGP Supply (Gulf)

57 Dracut Supply 1 - Baseload

58 Dracut Supply 2 - Swing

Dracut Supply 3 - Swing

59 Constellation Combo

60 LNG Truck

61 Propane Truck

62 PNGTS

63 Portland Natural Gas

64 TGP Supply (Z4)

65 Subtotal Pipeline Volumes

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67 Storage Gas:

68 TGP Storage

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70 Produced Gas:

71 LNG Vapor

72 Propane

73 Subtotal Produced Gas

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75 Less - Gas Refills:

76 LNG Truck

77 Propane

78 TGP Storage Refill

79 Subtotal Refills

80

81 Total Sendout Volumes

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Off Peak May - Oct
54 Dawn Supply	738,844	49,392	-	-	102,190	658,540	1,548,966
55 Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
56 TGP Supply (Gulf)	12,429	-	-	-	-	384,326	396,755
57 Dracut Supply 1 - Baseload	-	-	-	-	-	-	0
58 Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
Dracut Supply 3 - Swing	-	-	-	-	-	-	-
59 Constellation Combo	-	-	-	-	-	-	0
60 LNG Truck	44,883	18,131	-	-	55,566	20,602	139,181
61 Propane Truck	79,409	71,899	69,472	69,279	73,449	81,696	445,204
62 PNGTS	205,081	146,300	119,612	125,908	176,916	218,093	991,910
63 Portland Natural Gas	133,959	3,126	-	-	2,555	574,003	713,642
64 TGP Supply (Z4)	5,536,500	4,925,428	4,951,832	4,939,917	5,049,449	5,697,403	31,100,529
65 Subtotal Pipeline Volumes	7,419,517	5,755,086	5,683,400	5,680,904	6,051,547	8,758,514	39,348,969
66							
67 Storage Gas:							
68 TGP Storage	-	-	-	-	-	-	0
69							
70 Produced Gas:							
71 LNG Vapor	20,025	18,131	17,519	17,470	18,522	20,602	112,269
72 Propane	-	-	-	-	-	-	-
73 Subtotal Produced Gas	20,025	18,131	17,519	17,470	18,522	20,602	112,269
74							
75 Less - Gas Refills:							
76 LNG Truck	(44,883)	(18,131)	-	-	(55,566)	(20,602)	(139,181)
77 Propane	(79,409)	(71,899)	(69,472)	(69,279)	(73,449)	(81,696)	(445,204)
78 TGP Storage Refill	(2,340,825)	(2,937,251)	(3,363,645)	(3,301,310)	(2,570,071)	(1,435,717)	(15,948,820)
79 Subtotal Refills	(2,465,117)	(3,027,282)	(3,433,117)	(3,370,589)	(2,699,086)	(1,538,015)	(16,533,205)
80							
81 Total Sendout Volumes	4,974,426	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,928,033

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

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3 **Off Peak 2022 Summer Cost of Gas Filing**

4 **Capacity Utilization**

5 **Volumes (Therms)**

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11 **Pipeline Gas:**

12 Dawn Supply 1,678,006 4,000 7,360,000 23% 1,548,966 4,000 7,360,000 21%

13 Niagara Supply 3,576,596 3,122 5,744,480 62% 3,576,596 3,122 5,744,480 62%

14 TGP Supply (Gulf) 397,446 21,596 39,736,640 1% 396,755 21,596 39,736,640 1%

15 Dracut Supply 1 & 2 & 3 436,185 50,000 92,000,000 0% 436,185 50,000 92,000,000 0%

16 LNG Truck 139,181 - - - 139,181 - - -

17 Propane Truck 445,204 - - - 445,204 - - -

18 PNGTS 991,910 1,000 1,840,000 54% 991,910 1,000 1,840,000 54%

Portland Natural Gas 732,286 1,784 3,282,560 22% 713,642 1,784 3,282,560 22%

19 TGP Supply (Z4) 29,866,267 21,596 39,736,640 75% 31,100,529 21,596 39,736,640 78%

20 Other Purchased Resources - - - - - - - -

21

22 Subtotal Pipeline Volumes 38,263,081 39,348,969

23

24 **Storage Gas:**

25 0 0 25,792,710 0% - 25,792,710 0%

26

27 **Produced Gas:**

28 LNG Vapor 112,269 112,269

29 Propane - -

30

31 Subtotal Produced Gas 112,269 112,269

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33 **Less - Gas Refills:**

34 LNG Truck (139,181) (139,181)

35 Propane (445,204) (445,204)

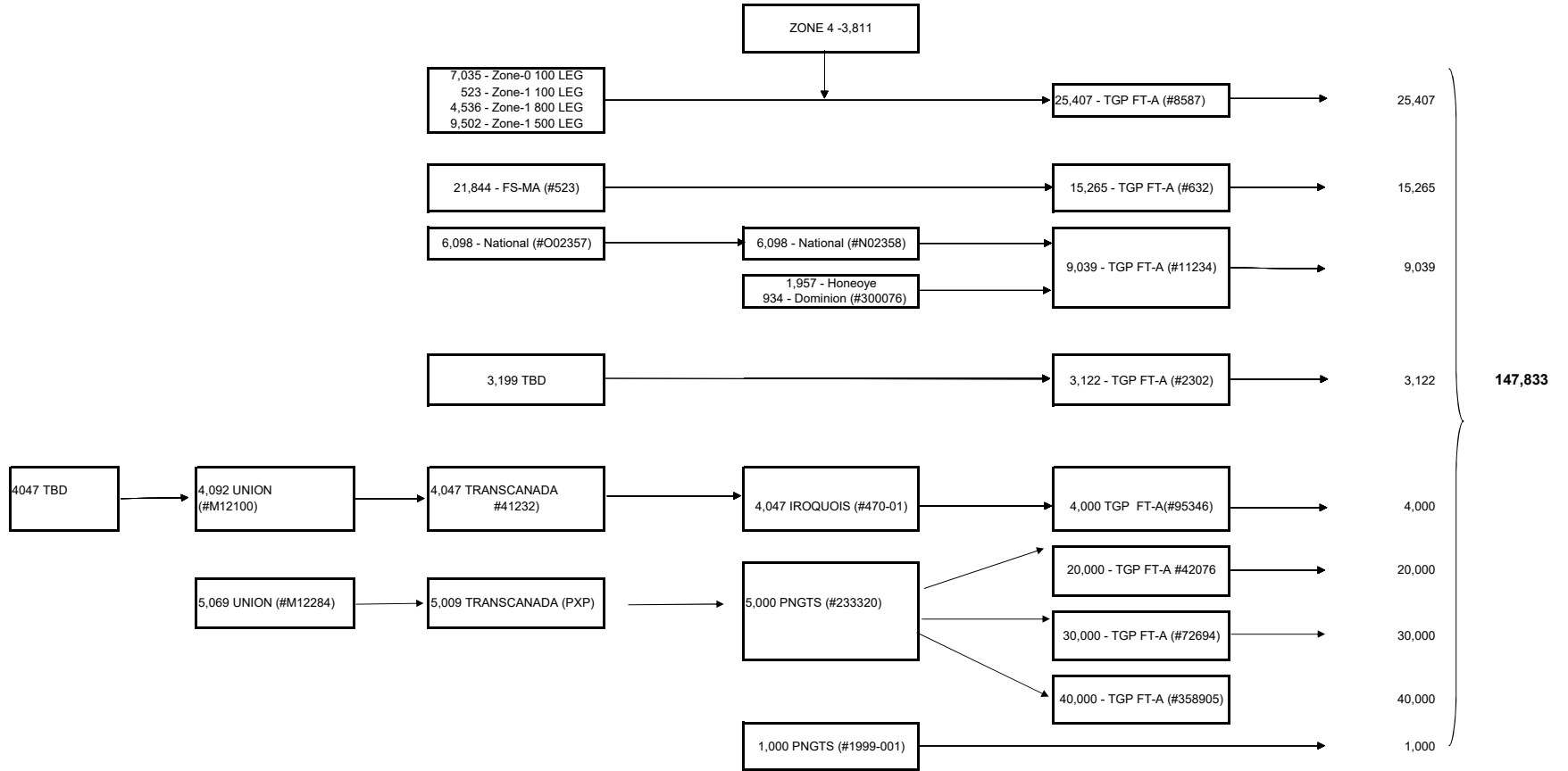
36 TGP Storage Refill (14,840,145) (15,948,820)

37

38 Subtotal Refills (15,424,530) (16,533,205)

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40 Total Sendout Volumes 22,950,820 22,928,033



Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing  
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
Constellation	FCS		Firm Combination Liquid and Vapor Svc	Up to 7 trucks	630,000	3/31/2022 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2022	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2022	N/A	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/A	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2024	3/31/2022	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2023	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2023	3/31/2022	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2023	3/31/2022	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 1999-01	1999-001	Transportation	1,000	365,000	11/30/2032	11/31/2031	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	4,432	1,617,680	10/31/2040	10/31/2039	Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2028	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2022	11/30/2021	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	358905	Transportation	40,000	14,600,000	10/31/2041	10/31/2040	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2026	10/31/2024	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	4,432	1,617,680	10/31/2040		Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2023	10/31/2021	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	4,432	1,617,680	10/31/2040		Precedent Agreement

\* MAQ is calculated on a 365 day calendar year.

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

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3 **Off Peak 2022 Summer Cost of Gas Filing**4 **Storage Inventory**

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6 **Underground Storage Gas**

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	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Estimate)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Total
Beginning Balance (MMBtu)	1,895,479	1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	1,951,935
Injections (MMBtu) Sch 11A In 39 /10	11,436	27,746	-	-	184,117	184,117	1,961,830
Subtotal	1,906,915	1,929,391	1,929,241	1,929,241	2,113,358	2,297,475	
Storage Sale	-	-	-	-	-	-	
Withdrawals (MMBtu) Sch 11A In 29 /10	(5,270)	(150)	-	-	-	-	(1,368,064)
Ending Balance (MMBtu)	1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	2,297,475	2,545,701
Beginning Balance	\$ 9,092,272	\$ 9,085,950	\$ 9,164,894	\$ 9,164,894	\$ 9,164,894	\$ 9,772,963	\$ 3,609,668
Injections In 11 * In 36	18,859	78,943	-	-	608,069	612,500	6,786,402
Subtotal	\$ 9,111,130	\$ 9,164,894	\$ 9,164,894	\$ 9,164,894	\$ 9,772,963	\$ 10,385,463	
Storage Sale	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Withdrawals In 17 * In 34	\$ (25,180)	\$ -	\$ -	\$ -	\$ -	\$ -	(2,634,626)
Ending Balance	\$ 9,085,950	\$ 9,164,894	\$ 9,164,894	\$ 9,164,894	\$ 9,772,963	\$ 10,385,463	\$ 7,761,444
Average Rate For Withdrawals In 22 /In 9	\$ 4.7779	\$ 4.7501	\$ 4.7505	\$ 4.7505	\$ 4.6244	\$ 4.5204	
TGP Storage Rate for Injections Actual or NYMEX plus TGP Transportation	\$ 1.6490	\$ 2.8452	\$ -	\$ -	\$ 3.3026	\$ 3.3267	

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

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39 **Off Peak 2022 Summer Cost of Gas Filing**

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41 **Liquid Propane Gas (LPG)**

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	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Estimate)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Total
44 Beginning Balance	93,824	93,828	94,844	94,844	94,844	94,844	96,655
45 Injections Sch 11A In 38 /10	72	1,016	-	-	-	-	49,431
46 Subtotal	93,896	94,844	94,844	94,844	94,844	94,844	
47 Withdrawals Sch 11A In 33 /10	(68)	-	-	-	-	-	(61,632)
48 Adjustment for change in temperature	-	-	-	-	-	-	-
49 Adjustment for Transfer	-	-	-	-	-	-	-
50 Ending Balance	93,828	94,844	94,844	94,844	94,844	94,844	84,454

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Beginning Balance	\$ 1,382,938	\$ 1,382,997	\$ 1,396,098	\$ 1,406,774	\$ 1,406,774	\$ 1,406,774	\$ 1,193,497
Injections In 46 * In 69	1,061	13,101	-	-	-	-	168,840
Subtotal	\$ 1,384,000	\$ 1,396,098	\$ 1,396,098	\$ 1,406,774	\$ 1,406,774	\$ 1,406,774	
Withdrawals In 52 * In 67	(1,002)	-	10,676	-	-	-	(763,126)
Ending Balance	\$ 1,382,997	\$ 1,396,098	\$ 1,406,774	\$ 1,406,774	\$ 1,406,774	\$ 1,406,774	\$ 599,211
Average Rate For Withdrawals	\$ 14.7397	\$ 14.7199	\$ 14.7199	\$ 14.8325	\$ 14.8325	\$ 14.8325	
Propane Rate for Injections Actual or Sch. 6, In 162 * 10	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	



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

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72 **Off Peak 2022 Summer Cost of Gas Filing**

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74 **Liquid Natural Gas (LNG)**

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	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Estimate)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Total
76 Beginning Balance	7,885	5,928	10,583	10,583	10,583	10,583	12,057
77 Injections Sch 11A In 37 /10	797	6,395	-	-	-	-	136,806
78 Subtotal	8,682	12,323	10,583	10,583	10,583	10,583	
81 Withdrawals Sch 11A In 32 /10	(2,754)	(1,740)	-	-	-	-	(132,648)
82 Ending Balance	5,928	10,583	10,583	10,583	10,583	10,583	16,216

86 Beginning Balance	\$ 34,430	\$ 25,885	\$ 42,850	\$ 42,850	\$ 42,850	\$ 42,850	\$ 135,659
88 Injections In 78 * In 99	3,480	24,011	-	-	-	-	653,097
89 Subtotal	\$ 37,910	\$ 49,896	\$ 42,850	\$ 42,850	\$ 42,850	\$ 42,850	
92 Withdrawals In 82 * In 97	(12,025)	(7,045)	-	-	-	-	(825,208)
93 Ending Balance	\$ 25,885	\$ 42,850	\$ 42,850	\$ 42,850	\$ 42,850	\$ 42,850	(36,451)

**EnergyNorth Winter 2021/2022 Cost of Gas and Summer 2022 Cost of Gas  
Summary of Changes from the Original filing to the Updated Filing**

	WINTER		SUMMER	
	RATE	IMPACT	RATE	IMPACT
<b><u>Original Filing Residential COG Rates excluding GAP – R-4</u></b>	<b>\$ 0.9056</b>		<b>\$ 0.5002</b>	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of \$208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	\$ 0.9034	\$ (0.0022)	\$ -	\$ -
Pricing Update	\$ 1.1339	\$ 0.2305	\$ 0.5587	\$ 0.5587
<b><u>Total Rate Change</u></b>		<b>\$ 0.2283</b>		<b>\$ 0.5587</b>
<hr/>				
<b><u>Original Filing Residential GAP COG Rates – R-4</u></b>	<b>\$ 0.4981</b>		<b>\$ 0.5002</b>	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of \$208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	\$ 0.4968	\$ (0.0013)	\$ -	\$ -
Pricing Update	\$ 0.6236	\$ 0.1268	\$ 0.5887	\$ 0.5887
<b><u>Total Rate Change</u></b>		<b>\$ 0.1255</b>		<b>\$ 0.5887</b>
<hr/>				
<b><u>Original Filing G-4 rates</u></b>	<b>\$ 0.9058</b>		<b>\$ 0.5007</b>	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of \$208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	\$ 0.9034	\$ (0.0024)	\$ -	\$ -
Pricing Update	\$ 1.1341	\$ 0.2307	\$ 0.5593	\$ 0.5593
<b><u>Total Rate Change</u></b>		<b>\$ 0.2283</b>		<b>\$ 0.5593</b>
<hr/>				
<b><u>Original Filing G-5 rates</u></b>	<b>\$ 0.9041</b>		<b>\$ 0.4994</b>	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of \$208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	\$ 0.9017	\$ (0.0024)	\$ -	\$ -
Pricing Update	\$ 1.1324	\$ 0.2307	\$ 0.5580	\$ 0.5580
<b><u>Total Rate Change</u></b>		<b>\$ 0.2283</b>		<b>\$ 0.5580</b>

\*The Company has not changed the FPO Rate, as letters were issued prior to the market changes.

<b><u>LDAC Adjustments</u></b>		
<b>Original Filing Total LDAC Rate</b>	\$	0.1733
<b>Updated Filing Total LDAC Rate</b>	\$	0.1444 \$ (0.0289)
Removed the prior year decoupling adjustment		
1. Removed lines relating to the RDAF adjustment on Tab 'Pk Tab 19 RDAF Page 1'		
2. Removed tab 'Pk Tab 19 RDAF Page 4' as it was sole related to the RDAF Adjustment		
3. Renumbered Schedules to indicate 'page n of 3' instead of 'pg. n of 4'		
Updated the environmental rate calculation to exclude the Blue Chip invoice identified in the Environmental Audit.		
	\$	0.1444 \$ -
<b>Total LDAC Rate Change</b>		<b>\$ (0.0289)</b>
<hr/>		
<b>Original Filing RDAF component of the Residential LDAC Rate</b>	\$	0.0459
<b>Updated Filing RDAF component of the LDAC Rate, this impacts residential only</b>	\$	0.0152 \$ (0.0307)
Removed the RDAF Adjustments		
1. Removed lines relating to the RDAF adjustment on Tab 'Pk Tab 19 RDAF Page 1'		
2. Removed tab 'Pk Tab 19 RDAF Page 4' as it was sole related to the RDAF Adjustment		
3. Renumbered Schedules to indicate 'page n of 3' instead of 'pg. n of 4'		
<b>Total LDAC Rate Change</b>		<b>\$ (0.0307)</b>
*This change resulted in a \$0.0307 reduction in the LDAC rate and the RDAF Component of the LDAC rate		
<hr/>		
<b>Original Filing Environmental component of the LDAC Rate</b>	\$	0.0155
<b>Updated Filing Environmental component of the LDAC Rate, this impacts both Residential and Commercial</b>	\$	0.0155 \$ -
Updated the environmental rate calculation to exclude the Blue Chip invoice for \$1,062 identified in the Environmental Audit.		
<b>Total Environmental Component Rate Change</b>		<b>\$ -</b>
*This change resulted in no change in the LDAC rate and the RDAF Component of the LDAC rate		
<hr/>		
<b>Original Filing GAP component of the LDAC Rate</b>	\$	0.0138
<b>Updated Filing GAP component of the LDAC Rate</b>	\$	0.0156 \$ 0.0018
This component changed due to the changes in COG rates		
<b>Total GAP component Rate Change</b>		<b>\$ 0.0018</b>
*This change resulted a \$0.0018 increase in the LDAC rate and the RDAF Component of the LDAC rate		
Updated the environmental rate calculation to exclude the Blue Chip invoice identified in the Environmental Audit.		
<hr/>		
Ties to total rate change for LDAC		