Proper Operation of the RDM

Allowed Revenue Targets (ART)

=

Actual Revenues Collected (ARC)

- Where ART and ARC are set on the same basis, then the differential represents the correct RDM adjustment.
- If ART > ARC, then revenue differential is collected by the Company
- If ART < ARC, then revenue differential is refunded to customers

Configuration 1: Allowed Revenue Targets Set by Customer Group

Allowed Revenue Targets

Targets are set for Residential Customers using R-3 Rate Schedule (non-discounted)

=

Actual Revenue Collected

Tariff Uses R-3 Rate Class Revenues for Calculation (non-discounted)

- Allowed Revenue Targets are set by **Customer Group** (Residential and C&I)
- Residential customers are served in the R-3 and R-4 rate classes.
- Residential rates are represented on R-3 Rate Schedule.
- R-4 rates are discounted from R-3 residential rates.
- Because R-3 and R-4 rate classes are not distinguished, R-3 rates are used for Allowed Revenue Targets

Configuration 2: Allowed Revenue Targets Set by Customer Class

Allowed Revenue Targets

Targets set using Rate Schedules approved for each customer class.

R-3 Non-Discounted

R-4 Discounted

≠

Actual Revenue Collected

Tariff Uses R-3 Rate Class Revenues for Calculation (non-discounted)

- **Allowed Revenue Targets are set by Customer Class**
- **R-3 Rate Schedule is not discounted**
- **R-4 Rate Schedule is discounted.**
- **Actual Revenue Collected is calculated using R-3 rates, non-discounted.**
- **Mismatch will indicate a customer refund is due because Actual Revenue Collected will be greater than Allowed Revenue Targets**

Liberty Utilities

EXHIBIT
#8
DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIRECT TESTIMONY

OF

GREGG H. THERRIEN

April 28, 2017

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ATTACHMENTS

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I. INTRODUCTION

Q. Please state your name, address and position.

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. My professional qualifications and experience have been provided in Attachment GHT/DECPL-11 to this testimony.

Q. Have you testified previously before the New Hampshire Public Utilities Commission ("PUC" or the "Commission)?

A. No, I have not.

Q. What is your responsibility in this proceeding?

A. In this proceeding, I am responsible for: (1) designing the Revenue Decoupling Mechanism (Decoupling Testimony of Gregg H. Therrien) and (2) together with Company Witness David Simek, developing the rate design (Joint Rate Design Testimony of David B. Simek and Gregg H. Therrien) for Liberty Utilities (EnergyNorth Natural Gas Corp.) d/b/a Liberty Utilities ("EnergyNorth", or "the Company").

II. SCOPE OF DECOUPLING TESTIMONY

Q. Please summarize the scope of your testimony concerning the Company's proposed Revenue Decoupling Mechanism ("RDM").

A. In this testimony, I will:

1) provide general background on RDMs, why they are necessary as part of a comprehensive energy efficiency program, and why traditional ratemaking is insufficient support for utility energy efficiency advocacy;

2) provide the results of our research on RDMs that have been implemented by gas Local Distribution Companies ("LDCs") throughout the U.S.;

3) describe the impact that EnergyNorth's Energy Efficiency ("EE") programs, customer self-funded conservation, and other external factors has had on the Company's throughput volumes and the effect on the Company's ability to earn a reasonable rate of return between rate cases;

4) describe my understanding of the recent energy efficiency settlement agreement in Docket No. DE 15-137, and how it recognizes the need to harmonize increased energy efficiency spending with appropriate changes in ratemaking; and

5) describe and explain the Company's proposed RDM, which will allow EnergyNorth to continue to be a forceful and active advocate for energy conservation efforts, without harming its ability to earn a reasonable return.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

In recent years, there has been a heightened focus on energy conservation efforts and policies that encourage conservation.[1] This interest in energy conservation has been attributed to environmental considerations and to a dramatic spike in energy prices that occurred in 2005 – 2006, and again in 2009. Although gas prices have dropped significantly since 2009, there has been price spikes in New Hampshire over the past three winters and the attention to gas conservation has continued.[2]

Since 2005, EnergyNorth has experienced a continuous decline in usage, as measured by Normalized Use per Customer ("NUPC"), in the Residential and Small Commercial and Industrial ("C&I") classes.[3] Continuing declines in the Residential Heating and Small C&I classes have been offset by increases in usage from the Large C&I customer classes. Despite EnergyNorth's overall customer usage remaining relatively flat over this time period, the Company has experienced significant year-to-year volatility in average use per customer.[4]

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[1] Heightened focus in New Hampshire on energy conservation efforts and enabling policies to encourage conservation are demonstrated in the following reports: (a) New Hampshire Independent Study of Energy Policy Issues (September 2011), prepared for the New Hampshire Public Utilities Commission by Vermont Energy Investment Corporation; (b) Increasing Energy Efficiency in New Hampshire: Realizing Our Potential, (November 2013), prepared for the New Hampshire Office of Energy and Planning by the Vermont Energy Investment Corporation; (c) New Hampshire 10-Year State Energy Strategy (September 2014), published by New Hampshire Office of Energy & Planning; and most recently (d) the Energy Efficiency Resource Standard Settlement Agreement (the "Settlement Agreement"), dated April 27, 2016, as approved in the New Hampshire Public Utilities Commission ("NHPUC") order in Docket No. DG 14-180 (dated August 2, 2016).

[2] On an annual basis, the average Cost of Gas charged by EnergyNorth to firm sales customers has decreased from $1.18 per therm to $0.72 per therm between December 2009 and August 2013, a decrease of 40 percent. Since 2013 prices have trended even lower, despite increasing winter volatility. As of December 2016, EnergyNorth firm sales average annual customer average Cost of Gas is $0.50 per therm.

[3] These classes account for approximately 66% of the Company's total firm throughput, based on 2016 normalized consumption.

[4] The volatility in EnergyNorth's 12-month rolling Total firm NUPC is demonstrated by the following trend in standard deviation (in therms):
2006-2009 = 31.66

EnergyNorth is not alone - most US gas distribution companies have been experiencing similar patterns of declining use[5], and have responded by implementing RDMs in 29 different states.

EnergyNorth proposes to implement rate design measures[6] that will "decouple" the traditional connections between the volume of gas that EnergyNorth delivers to its customers and its revenues and earnings.

The decoupling rate design measures that the Company is proposing:

– Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;

– Will comport with the State of New Hampshire's vision in its 2014 State Energy Strategy, which recognized that "[r]ealigning utility incentives to reward utilities for investing in efficiency is a necessary part of any effort to increase efficiency in New Hampshire"; [7]

2010-2013 = 14.95
2014-2016 = 21.48
These standard deviations indicate that volatility was highest during the 2006 – 2009 era of high gas prices, lowest post-shale supply influx, and increasing over the past three years as a result of the polar vortex and tight New England supplies. This is discussed in detail in Section IV. D. 3. of this testimony.

5 This trend was examined extensively by such organizations as the American Gas Association, which reported a trend in declining use per residential natural gas customer of 1 percent annually from 1980 to 2000, and accelerated thereafter. *See* An Economic Analysis of Consumer Response to Natural Gas Prices, by Frederick Joutz and Robert P. Trost, prepared for the AGA, March 2007.

6 Specifically, the Company's proposed RDM and the Company's rate design proposals, which increase the proportion of the Company's total distribution revenues that are derived from customer charge revenues.

7 New Hampshire 10-Year State Energy Strategy, published by the New Hampshire Office of Energy & Planning September 2014. Executive Summary, page ii.

– Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[8] by producing equitable ratemaking beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals, and enables full acceptance of the energy savings initiatives envisioned in the Settlement Agreement; and

– Will fix a flaw in the traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

III. OVERVIEW OF DECOUPLING

A. Introduction

Q. Please describe a revenue decoupling mechanism.

A. In general terms, an RDM breaks the link between the quantities that a utility delivers to its customers and that utility's revenues. By eliminating the link between customer consumption and Company earnings, decoupling removes the disincentive for utilities to promote conservation and energy efficiency programs. Companies that have implemented decoupling are no longer caught between promoting conservation (that reduce sales) and growing revenues (by increasing sales). Breaking the link between

[8] The "Settling Parties" as defined in the Settlement Agreement approved in Docket No. DG 15-137, dated August 2, 2016, include: Commission Staff, Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire dba / Eversource Energy; the New Hampshire Electric Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way home; the Conservation Law foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development finance Authority; and TRC Energy Services.

utility sales and revenues is the best way to promote conservation activities fully and freely. Other mechanisms that only compensate the utility for the costs of conservation programs, such as a Lost Revenue Adjustment Mechanism ("LRAM"), fall short.

Q. Why is a LRAM insufficient in promoting conservation programs?

A. Mechanisms such as the recently approved LRAM in New Hampshire only compensate for energy efficiency measures installed as a result of utility programs, and alone do not promote conservation behaviors. The American Council for an Energy Efficient Economy ("ACEEE"), a nonprofit, 501(c)(3) organization, whose stated mission is to "act(s) as a catalyst to advance energy efficiency policies, programs, technologies, investments, and behaviors"[9] states:

> "An LRAM alone will not fully incentivize efficiency nor remove the throughput incentive. While the lost revenue adjustment can help make a utility whole by compensating it for reduced energy sales associated with efficiency programs, it will do little to encourage investment in energy efficiency unless combined with other policy levers. In fact, our analyses indicate that having an LRAM policy itself is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than are found in states without an LRAM policy. Nor does LRAM reduce a utility's motivation to increase sales (although some states do have safety nets in place). To fully remove the throughput incentive, decoupling should be considered."[10]

[9] *See* http://aceee.org/about-us.
[10] "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms", June 2015, ACEEE Report U1503.

Q. How does a decoupling mechanism work?

A. RDMs generally adjust rates on a periodic basis (e.g. annually or seasonally) to "make up" the difference between a target revenue per customer, which would have been set in the most recent rate case, and actual revenue per customer. RDMs are symmetrical; the calculation can result in either a charge or credit depending on the actual revenue per customer. A rate adjustment credit will be included in customers' bills in a future period when actual revenue per customer is greater than the target revenue per customer in a recently-completed period. Conversely, a rate adjustment charge will be included in customers' bills when actual revenue per customer is less than the target revenue per customer.

Q. Why do utilities need decoupling?

A. Utilities are becoming increasingly responsible for managing and actively promoting customer conservation through the development and implementation of robust energy efficiency programs. All else being equal, these programs will result in lower NUPC. In addition, utility customers have become increasingly aware of energy use and have invested in energy efficiency measures with their own dollars. Further, appliance efficiency improvements and stricter building code requirements result in higher overall energy efficiencies when customer equipment and existing building stock are replaced. Lastly, other external factors such as economic factors, demographics, and weather trends can contribute to changes in consumption. While reduced energy usage is good for individual consumers and society as a whole, it does have a negative impact on a utility's ability to earn its allowed rate of return under traditional ratemaking.

Q. Please elaborate on the utility earnings dilemma.

A. The Company's financial performance, all else being equal, is negatively affected by declining NUPC. Decoupling is an appropriate and increasingly common component of a well-designed and implemented demand-side management ("DSM") program. Decoupling is appropriate whenever a utility's rates are designed such that a decrease in sales volumes adversely affects the ability of the utility to earn a reasonable return on investment. According to the Regulatory Assistance Project ("RAP"):

> "Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers."[11]

Q. Why should policy-makers and customers support decoupling?

A. As discussed above, decoupling unlocks the utility's ability to enthusiastically support energy efficiency policy goals. Over time, decoupling mechanisms provide rate stability that results from the mechanism's symmetrical design.[12] Further, decoupling can protect customers from a utility recovering excess revenues that may result from colder than normal weather or from favorable economic conditions.

[11] "Revenue Regulation and Decoupling: A Guide to Theory and Application", November 2016, page 26.
[12] RAP also recognizes this, stating, "Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable." Ibid, page 26.

B. <u>Support for Decoupling: Energy Efficiency Programs</u>

Q. Why is decoupling important for regulated utilities that offer energy efficiency programs?

A. The ACEEE best summarized the importance of decoupling for regulated utilities in its June 2014 Policy Brief titled "Utility Initiatives: Alternative Business Models and Incentive Mechanisms" where it stated that:

> "Under traditional rate-of-return regulation, utilities have an economic disincentive to provide programs to help their customers be more energy efficient. Because a utility's earnings are based on the total amount of capital invested and the amount of electricity sold, increased energy sales generally increase utility profits. Experience suggests that enacting regulatory reforms such as decoupling…help overcome those inherent disincentives regarding energy efficiency.'

Further, in its June 2015 Report titled "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms" [13] they state:

> "Creating a regulatory environment that incentivizes utilities to invest in efficiency is critical for programs to be successful, impactful, and long lasting. Doing so requires a mix of policy tools. In addition to energy efficiency targets, utilities need a business model that aligns their financial interests with energy efficiency, including program cost recovery, performance incentives that encourage utilities to achieve high levels of savings, and some policy mechanism to neutralize the throughput incentive. It is our opinion that decoupling is the best third leg of this stool. However, it is also clear that decoupling is not always an option for states for a variety of reasons. In such scenarios, LRAM can be a temporary solution, offering a mechanism to address the

[13] Report U1503.

> concern over lost revenues and, possibly, help make parties more comfortable with the idea of full decoupling in the future.

These ACEEE policy excerpts clearly show the need for, and evolution of, utility ratemaking that supports energy efficiency goals.

C. **Support for Decoupling: Ratemaking**

Q. Please describe and explain the structure of decoupling mechanisms.

A. RDMs calculate a surplus or shortfall between actual and allowed revenues. There are two common RDM structures: (a) revenue per customer ("RPC") RDMs and (b) total revenue RDMs. The primary difference between these two structures is the revenue "true up" calculation and the treatment of new customers. The RPC RDM revenue true up determines the revenue shortfall or surplus by (a) calculating the difference between the target RPC and actual current period RPC by customer group or rate class and (b) multiplying the difference per customer ("RDM per Customer Adjustment") by the current period number of customers. The effect of a RPC RDM is that the sum of actual rate class/rate group revenues per customer plus the RPC RDM per customer adjustment will always equal the target RPC, and total actual revenues will change in direct proportion to the change in the number of customers between the test year and current period. New customer revenues are therefore preserved to fund new customer investment made by the utility.

The total revenue true up determines the revenue shortfall or surplus by calculating the difference between the target revenues and actual current period revenues by customer group or rate class. The effect of a Total Revenue RDM is that the sum of actual rate class/rate group revenues plus the Total Revenue RDM true up for each rate class/rate group will always equal the revenue target and total actual revenues will not change until the LDC's next rate case. There is no inherent recognition of new customer additions in this approach.

Q. Of these two types of RDM, which is most common for gas LDCs?

A. The application of a RPC RDM best suits utilities that add new customers to their system, and is the prevalent methodology among LDCs that have decoupling. Unlike electric distribution companies, gas LDCs typically do not have 100% market share in their service territories and are motivated to convert customers from alternate fuels, such as oil or propane. Adding new customers to the system involves incremental capital investment, which requires that the revenues from these new customers be necessarily retained by the Company to fund this new investment. Therefore, RPC RDMs are superior to Total Revenue RDMs for gas utilities, as new customer revenues are retained (at the system average RPC) to help cover the cost of the corresponding new investment. If a Total Revenue RDM is employed instead, then the LDCs incentive to add new customers is significantly diminished, as total revenues will remain unchanged while rate base grows.

Q. Does decoupling guarantee utility earnings?

A. No, it does not. The proposed RDM trues up revenues to the amount allowed on a per-customer basis. The utility remains at risk for managing its expenses commensurate with the level set for the test year base rates. This means the utility must manage its capital expenditure programs, its operations (e.g., salaries and wages, benefits, overtime, maintenance programs, uncollectibles, outside services, etc.), and pay taxes (including property taxes that are adjusted annually by most municipalities).

D. LDC Experience with Decoupling

1. Decoupling in the U.S.

Q. Please summarize your research on U.S. gas LDCs that have implemented RDMs.

A. I have identified 67 gas LDCs in 29 states that have implemented a RPC RDM or a Total Revenues RDM. This is summarized as follows:

Table 1: Revenue Decoupling Mechanisms in Effect in the U.S.

State	RPC RDM	Total Revenue RDM	Grand Total
AR	1	2	3
AZ	1		1
CA		4	4
CO	1		1
CT		1	1
GA		1	1
ID		1	1
IL	2	1	3
IN		3	3
LA		1	1
MA	6		6
MD	4	1	5
MI	1		1
MN	1	1	2
MS		1	1
NC	1	1	2
NJ	2		2
NV	1		1
NY	9	2	11
OR	2	1	3
RI	1		1
SC		1	1
TN	1		1
UT	1		1
VA	3		3
VT		1	1
WA	2	1	3
WI	1		1
WY	2		2
Grand Total	**43**	**24**	**67**

Q. Do any LDCs with RDMs also have other ratemaking adjustment mechanisms?

A. Yes, many LDCs with RDMs have also sought recovery of certain expenses and investments (plant / rate base additions) between general rate cases. Cost-related modifications to traditional ratemaking include several approaches to adjusting rates between rate cases to account for changes in (a) overall costs or (b) specific categories of costs. Rate plans that provide for allowed annual increases in a utility's allowed revenues[14] for a set number of years after the rate case is decided is an example of cost based departures that account for changes in overall costs. Step Adjustment increases are common practice in New Hampshire; step adjustments are a form of a rate plan.

Cost tracker mechanisms are another category of modifications to traditional gas LDC ratemaking. Cost trackers recover actual costs incurred on a timely basis. For example, capital cost trackers allow for periodic rate adjustments to recover the incremental revenue requirements associated with replacement and/or safety and reliability projects, while expense cost trackers recover certain specific expenses on a timely basis. New Hampshire has implemented some of these cost tracking measures, including the Cost of Gas Adjustment ("CGA"), indirect gas costs, EE/DSM program costs, environmental remediation costs, and the Cast Iron and Bare Steel ("CIBS") mechanism.

Common cost tracking mechanisms include:

a. Gas costs[15];
b. Pension and Post-Retirement Benefits Other than Pensions ("PBOP") expense;
c. Bad debt expense;
d. Environmental response costs;
e. EE program expense;
f. Property and/or franchise taxes;

[14] For example, the annual revenue increases may be (a) determined for each year of the rate plan in a rate case proceeding, or (b) calculated annually during the rate plan by a formula that accounts for changes in a price index.

[15] Recovery of gas costs through a rate adjustment mechanism is now so common that it is generally considered to be part of "traditional ratemaking."

g. Infrastructure replacement costs (e.g., CIBS);
h. System reinforcement costs, and
i. Integrity management costs.

The following table summarizes the prevalence of pairing an RDM with a cost tracker:

Table 2: LDCs With Decoupling and Cost Tracker

RDM Type	With a Tracker	No Tracker	Total
RPC	25	18	43
Total Revenue	20	4	24
Total	45	22	67

A complete listing of the 67 LDCs that currently have decoupling is included in Attachment GHT/DECPL-1.

Q. Have you identified any other common features in the structure of RDMs that you identified in your research?

A. Yes, I have. In Section III.A of this testimony, I explain that an RDM revenue true up calculation determines the difference between (a) Target RPC and Actual RPC or (b) Target Revenues and Actual Revenues. Both of these approaches to calculating the revenue true up account for differences in revenues that are the result of weather that is colder or warmer than normal in addition to accounting for differences due to conservation and related factors. For example, if weather in the current time period was colder than normal, the RDM would return to customers the revenue surplus associated with the colder weather in the following winter period, and if weather was warmer than normal, the RDM true up calculation would include a charge to recover the revenue deficiency associated with the warmer weather.

Alternatively, an RDM revenue true up calculation could determine the difference between (a) Target RPC and weather normalized RPC or (b) Target Revenues and weather normalized revenues. The true up calculation could be performed by determining the difference between target revenues and weather normalized actual revenues. Using this approach, the revenue true up calculation would not be affected by colder or warmer than normal weather.

Q. What does your research on RDMs indicate about the prevalence of RDMs that are based on actual revenues and RDMs that are based on weather normalized revenues?

A. I determined that 57 of the 67 LDCs have implemented RDMs that are based on actual revenues. Of the remaining 10 LDCs that have implemented RDMs based on normalized revenues, 7 have separate weather normalization adjustment mechanisms ("WNA").

Q. In your opinion, why are most RDMs – approximately 85 percent – based on actual revenues?

A. It is my belief that RDMs that are based on actual revenues, rather than weather normalized revenues, are more common because this RDM approach is easier to administer and oversee as the review process is straight-forward. RDMs that use actual revenues capture all sales-related variances, thus avoiding the need for a WNA (and explanation of its mechanics to customers) or a complicated normalization calculation and subsequent Commission review. Either (a) an RDM that is based on actual revenues or (b) an RDM that is based on weather normalized revenues together with a weather normalization adjustment mechanism have symmetrical, balanced effects that stabilize customers' bills and LDCs' revenues.

Q. What conclusions do you draw from the number of LDCs that have adopted revenue-related and cost-related modifications to traditional ratemaking?

A. Based on the widespread adoption of decoupling mechanisms (67 LDCs in 29 states; see Section III.D.1), of which 45 of these LDCs (two thirds) also have some form of cost tracker, I conclude that there is general understanding that (a) decoupling mechanisms are now viewed as an appropriate ratemaking approach that remove LDC disincentives to effectively promote EE programs and offset the overall effect of conservation on LDC revenues and earnings (b) cost tracking measures are now viewed as an appropriate approach to partially offsetting the effect of LDCs' capital spending plans on earnings between rate cases, and (c) the combination of a decoupling mechanism paired with an appropriate cost tracking measure may be necessary to provide a reasonable opportunity to earn a fair return.

2. Summary and Conclusion to Decoupling Overview

Q. Please summarize your findings about decoupling.

A. Over the past decade or longer, there has been considerable attention given to decoupling, which I believe is the result of a growing acceptance that decoupling is a balanced and administratively manageable ratemaking tool that will: (a) break the link between a utility's revenues and the amount of energy that the utility delivers or sells; and (b) address problems with traditional ratemaking that are caused by long term trends of declining customer energy usage.

I have found that, because LDCs in a number of states have adopted decoupling mechanisms over the last decade, there is now a rich source of data available concerning features of RDMs that have been implemented and issues related to the administration and implementation of RDMs, including, for example, RDM calculations and filing documentation.

IV. ENERGYNORTH'S EXPERIENCE

A. Introduction

Q. In Section III above, you provided a discussion of circumstances that would support the implementation of an RDM. Do those circumstances apply specifically to EnergyNorth?

A. Yes. As I will explain in the remainder of this section, EnergyNorth's circumstances demonstrate that an RDM is appropriate and justified for the Company. Specifically, I will:

- Describe EnergyNorth's current EE programs;
- Summarize the 2015 EERS Settlement Agreement;
- Describe and explain EnergyNorth's recent customer and revenue per customer trends; and
- Demonstrate that EnergyNorth's level of involvement in and support for EE

programs warrant the implementation of an RDM.

B. <u>EnergyNorth's Energy Efficiency programs</u>

Q. Please provide some background on EnergyNorth's EE programs.

A. EnergyNorth has been offering EE programs to its customers since 2003 that provide rebates and technical support for residential and commercial customers who seek to minimize their energy use.[16]. Table 3 below provides a summary of the actual and planned direct energy savings that result from EnergyNorth's EE programs.

[16] Referred to as the "Core programs" in the EERS Settlement Agreement.

1 **Table 3: EnergyNorth Energy Efficiency Program Savings (Annual Dth)**

Year	Actual / Estimate	Residential	C&I	Total Energy Savings
2006	Actual	25,529	47,269	72,797
2007		27,151	104,730	131,881
2008		35,360	48,278	83,638
2009		32,414	88,174	120,588
2010		43,524	34,703	78,227
2011		29,281	46,466	75,747
2012		39,702	108,565	148,267
2013		40,509	74,831	115,340
2014		34,401	82,545	116,946
2015		63,685	80,069	143,754
2016	Plan[17]	57,226	65,118	122,344
2017	Proposed Savings Targets	57,791	65,762	123,553
2018		61,594	70,088	131,682
2019		66,158	75,280	141,438
2020		69,958	79,606	149,564

2

3 Q. **Is the intent of the EE program incentive payment to compensate EnergyNorth for**
4 **foregone EE revenues?**

5 A. No, the incentive payment is intended to "incent the utilities to aggressively pursue
6 achievement of the performance goals of their energy efficiency programs" and "to
7 motivate the companies to achieve or exceed program goals".[18] It is not intended to
8 offset EnergyNorth's foregone EE revenues.

[17] Settlement Agreement, Attachment B.
[18] *Energy Efficiency Programs for Gas and Electric Utilities,* Order No. 24,203 at 13 (September 5, 2003).

C. The EERS Settlement Agreement

Q. Please describe the EERS Settlement Agreement.

A. The Company, along with the Settling Parties, entered into a Settlement Agreement on April 27, 2016, more than a year after the inception of the Commission's investigation of Staff's proposed Energy Efficiency Resource Standard.[19] The Settlement Agreement represents the Parties' implementation of the approved EERS in New Hampshire,[20] and specifically:

1) Extends the Core programs;
2) Requires implementation of a LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);
3) Contemplates the subsequent implementation of a decoupling mechanism to replace the LRAM;
4) Will implement the EERS commencing January 1, 2018;
5) Retains the Performance Incentive, with modifications;
6) Increases the low income share of the overall energy efficiency budget; and
7) Includes other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (August 2, 2016).

[19] Docket No. IR 15-072, "Electric and Natural Gas Utilities - Energy Efficiency Investigation" dated March 13, 2015.
[20] Settlement Agreement, page 2.

Q. Please describe EnergyNorth's Implementation of the LRAM.

A. EnergyNorth implemented the LRAM effective January 1, 2017.[21] The Local Distribution Adjustment Charge ("LDAC") includes an embedded LRAM of $0.0016/therm and $0.0009 per therm for Residential and C&I customers, respectively. This LRAM will remain in effect (as part of the LDAC) until it is either recalculated for 2018 deliveries or replaced by the proposed decoupling mechanism described in Section V below.

Q. Does the Commission's Order approving the Settlement Agreement specifically require the Utilities, such as EnergyNorth, to implement decoupling?

A. Yes. The Commission approved the Settling Parties' proposed LRAM, and recognized that some parties prefer decoupling to an LRAM. Specifically, the Order states:

> "We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC)) are *required* to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before" (*emphasis added*).[22]

[21] Docket No. DG 16-814, "Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities -2016/2017 Cost of Gas", noticed on September 16, 2016. Approved by Commission Order No. 25,958 (October 26, 2016).
[22] Order No. 25,932 at 60.

Q. Is it the Company's position that proposing a decoupling mechanism in the instant proceeding comports with the Settlement Agreement and the Order?

A. Yes. The phrase "if not before" from the above caption clearly allows the Company to propose a decoupling mechanism prior to the end of the first EERS triennium, if desired.

D. <u>Impact of Customer Consumption Trends on EnergyNorth</u>

1. Introduction

Q. To set the stage for your discussion of the impacts of declining consumption on Energy North, please describe the analysis that you have prepared.

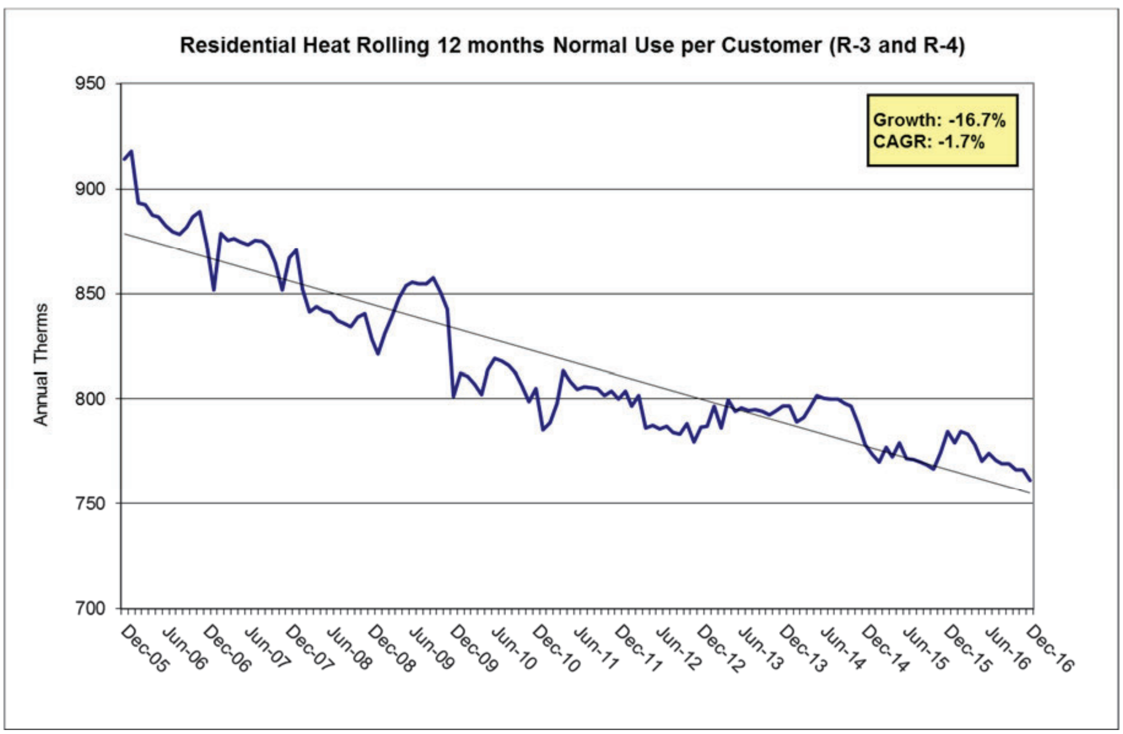
A. In this section, I discuss trends in EnergyNorth's NUPC and number of customers since 2005. I provide summary analyses that I prepared for the following customer groups: (a) Residential Non-Heating; (b) Residential Heating; (c) Low Load Factor C&I; (d) High Load Factor C&I; and (e) Total Company. I prepared separate analyses for the Residential and C&I Customer Groups because customers in these two groups have generally behaved very differently over the period of analysis, 2005 to 2016, particularly the High Load Factor C&I group. I also offer high level explanations for the changes in deliveries, customers and use per customer that EnergyNorth has experienced in the past several years.

2. Analysis of UPC and customer trends

Q. Please summarize the trends in EnergyNorth's weather NUPC that you have identified.

A. To identify trends in EnergyNorth's NUPC, I prepared Residential (Heating and Non-Heating), C&I (Low and High Load Factor) and Total Company NUPC graphs. These graphs are based on a 12-month rolling total NUPC, and are provided in Attachment GHT/DECPL-2. The first graph in Attachment GHT/DECPL-2 shows the NUPC for the Residential Heating Customer Class. A snapshot of this chart is as follows:

Chart 1: Residential Heating NUPC Snapshot



NUPC for the Residential Heating customer class declined 16.7% during the period of analysis, from 912 therms per customer in 2005 to 761 therms per customer in 2016, representing an average annual decline of 1.7%.[23] More recently, from 2013 to 2016 the Residential Heating class has declined at a similar rate of 1.5%.

The Residential Non-Heating NUPC in Attachment GHT/DECPL-2 shows a relatively level usage profile over time, with a 5.3% decline since 2005, or a -0.5% CAGR. Since 2013 NUPC for this class has decreased 12.4%, or 4.3%, primarily as a result of customer rate classification changes. At the conclusion of the last rate case in Docket No. DG 14-180 the Company discovered that 540 existing Rate R-1 customers should have been served under Rate R-3. Following that discovery, the Company initiated a program to convert these customers to Rate R-3.

The two C&I graphs in GHT/DECPL-2 show diverging trends depending on how customers in these classes use natural gas. Low Load Factor ("LLF") customers use gas predominantly for heating, while High Load Factor ("HLF") C&I customers tend to utilize natural gas for process loads, and are potentially subjected to multiple and unique usage drivers compared to LLFr C&I customers (and Residential Heating customers). As these two C&I graphs show, the LLF customer group had declining NUPC from 2005-2010, then rebounded back to 2005 levels by 2014. Their growth rate from 2005 to 2016 showed a slight decline at 0.2%, and a flat CAGR. Conversely, the HLF customer group exhibited rapid NUPC growth over the eleven-year historical period, growing 58.3%, or

[23] As calculated on the Compound Annual Growth Rate ("CAGR") formula.

4.3% annually. Since 2013 the LLF C&I group has remained flat (a 0.1% increase in NUPC) while the HLF C&I class' growth was comparatively lower (0.7% growth since 2013 compared to 4.3% CAGR since 2005).

The last graph in Attachment GHT/DECPL-2 shows that total company NUPC increased slightly by 2.3% percent, or 0.2% annually, which indicates that overall, the increasing HLF C&I NUPC offset much of the decreasing Residential and LLF C&I NUPC over the entire period. Of interest is the recent increase in volatility, including a declining overall NUPC trend since December 2013 of 2.0%. This is likely the result of recent winter period price spikes described further in Section IV.D.3 below.

Q. Please summarize the trends in EnergyNorth's number of customers that you have identified.

A. To identify trends in EnergyNorth's customer counts, I prepared graphs of the number of Residential, C&I and Total Company customers; these graphs are provided in Attachment GHT/DECPL-3. The first graph in Attachment GHT/DECPL-3 shows that the average number of Residential Non-Heating customers decreased by 2,285 (42.9%), or 5.0% annually. This is not surprising, as many low-use customers have converted their heating system to gas over the past decade, taking advantage of the favorable gas-to-oil price spread described in Section IV.D.3 and Table 6 below. The average Residential Heating customer class has increased by 9,914 customers (15.0%), or 1.3% annually. This increase is attributable to heating conversions and new customer attachments to the system (e.g., oil-to-gas conversions and new construction). This growth rate accelerated to 1.8% since 2013.

The next two graphs in Attachment GHT/DECPL-3 show that the number of LLF C&I average customers grew by 1,590 (18.6%), or 1.6% annually, while the HLF C&I class decreased by 86 customers on average, a 5.1% decrease (-0.5% annually).

The last graph in Attachment GHT/DECPL-3 demonstrates that the overall Company customer growth reflects an annual 1.0% growth in average firm customer count. Since the dramatic increase in the oil-to-gas price spread (using a 2013 base), the Residential Heating class has increased to a 1.8% annual growth rate.

3. Explanation for UPC and Customer trends

Q. What are the major contributors to declining NUPC?

A. Categorically, declining NUPC can be attributable to:

1) Utility-sponsored Energy Efficiency (EE)/DSM programs;
2) Customer self-funded conservation measures;
3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to increases in natural gas prices and/other economic and demographic factors; and
5) A warmer normal weather trend.

Q. Please explain each of these factors.

A. Utility-sponsored EE/DSM programs represent the Core programs, plus any additional programs contemplated in the EERS. These measures result in direct energy efficiency spending for EnergyNorth customers. Each program will have an avoided unit of energy and known levels of participation.

Customer self-funded conservation measures are the result of customers acting independently of utility-sponsored programs (e.g., when a customer installs insulation purchased at a home improvement store). Unlike company-funded conservation programs that track actual installed energy efficiency measures, the utility does not track customer-funded installations.

Appliance efficiencies and building code changes affect customer usage whenever an existing (less efficient) appliance is replaced by a new (more efficient) one, and new housing stock replaces old stock. There are known changes to building requirements and appliance efficiency standards that have been enacted over the past few decades. These include increased appliance efficiency requirements for furnaces and hot water heaters. Additionally, New Hampshire has passed a series of more stringent building codes consistent with national standards.

Price elasticity and economic impact on usage can be estimated using econometric modeling, but will have less of a degree of accuracy compared to known and measurable

EE/DSM installations. Although prices are low now[24], in the not so distant past, prices were high and customers responded by installing low cost permanent measures (weather stripping, water heater jackets, set back thermostats, etc.) and high cost permanent measures (insulated doors, added wall and attic insulation, efficient windows, etc.) as well as temporary measures (closing off rooms, turning down thermostats and wearing sweaters). The permanent measures reduce NUPC forever, long after the natural gas prices return to moderate levels. Further, changes in demographics (e.g., number of people per household, number of residents in a service territory or state) can also influence NUPC. Lastly, a significant downward trend in the 30-year normal weather standard also contributes to declining NUPC.

Q. What are the current and forecasted trends for each of these factors?

A. New Hampshire is clearly committed to EE, evidenced by the Settling Parties' commitment to implementing a comprehensive EERS in 2018. Customer-funded conservation measures are likely to continue, as low-cost weatherization options proliferate the home improvement marketplace. Even if the current appliance efficiencies and building codes do not change in the coming years, customer equipment and housing stock will be replaced resulting in net energy savings (e.g., replacing a failed gas furnace with a new gas furnace). Although the gas-to-oil pricing advantage has shrunk since

[24] The U.S. Energy Information Administration ("EIA") Annual Energy Outlook 2017 forecast of residential delivered cost of natural gas shows stable prices through 2025 (2017 forecast = $1.06 per therm compared to the forecasted 2025 delivered price of $1.14 per therm).

2012, the EIA is forecasting a return to a price spread where oil is twice the delivered price of natural gas.[25]

Q. Please elaborate on how customer-funded conservation contributes to declining NUPC.

A. Existing customers have chosen to invest in conservation measures using their own money without utilizing utility-sponsored EE programs. This occurs because of either a lack of understanding of the existence of utility programs or ineligibility based on program requirements. The quantification of energy savings for an individual, representative premise is easily obtainable for many conservation measures. The effectiveness of thermal resistance, for instance, is measured in "R-value" units. Increasing a surface's R-value reduces heat loss. Therefore, when a consumer installs additional insulation in their home, thus increasing the surface's R-value (e.g., attic floor, ceilings, walls, etc.) their natural gas usage (all else being equal) will decline. The following table demonstrates the impact of increasing R-values in a sample 1,000 square foot home in Concord, New Hampshire:

[25] EIA Annual Energy Outlook 2017.

Table 4: Potential Energy Savings from Increased R-Value [26]

Percentage Savings (therms)												
			OLD									
NEW	R-Value	Δ in R	R-10	R-11	R-12	R-13	R-14	R-15	R-16	R-17	R-18	R-19
	R-11	1	2.0%									
	R-12	2	3.7%	1.7%								
	R-13	3	5.1%	3.1%	1.4%							
	R-14	4	6.3%	4.3%	2.6%	1.2%						
	R-15	5	7.4%	5.4%	3.7%	2.3%	1.0%					
	R-16	6	8.3%	6.3%	4.6%	3.2%	2.0%	0.9%				
	R-17	7	9.1%	7.1%	5.4%	4.0%	2.8%	1.7%	0.8%			
	R-18	8	9.8%	7.8%	6.1%	4.7%	3.5%	2.5%	1.5%	0.7%		
	R-19	9	10.5%	8.5%	6.8%	5.4%	4.1%	3.1%	2.2%	1.4%	0.6%	
	R-20	10	11.0%	9.0%	7.4%	5.9%	4.7%	3.7%	2.8%	1.9%	1.2%	0.6%

As the above table indicates, an existing homeowner who upgrades their home with insulation, which increases the overall R-value of the dwelling, can decrease their natural gas usage significantly. For example, increasing the R-value from R-10 to R-16 would reduce annual usage from 682 to 626 therms, more than eight percent. Even a modest improvement in R-value can have a significant impact on declining usage.

Q. Please elaborate on how increased appliance efficiencies contribute to declining NUPC.

A. Appliance manufacturers have been improving the energy efficiencies of their gas equipment on both a mandated and voluntary basis. The U.S. Department of Energy ("DOE") regulates minimum efficiency standards for many appliances, including gas furnaces, boilers, and water heaters. In the early 1990s the DOE changed the standards on Annual Fuel Utilization Efficiency ("AFUE") factors. Under the new code, a gas furnace was required to meet at least an 80% AFUE while high efficient gas furnaces

[26] The average usage for a 1,000-square foot house in Concord, NH is estimated at 682 therms per year, using the estimator tool found at www.energydepot.com/residentialenergycalculator. The quantification of saved therms assumes EnergyNorth's normal annual heating degree days of 6,273 and utilizes the Insulation Investment Calculator found at www.chuck-wright.com/calculators/insulpb.html.

must achieve at least an 90% AFUE to meet the new standard. This is an increase from the 78% AFUE standard enacted in 1992.[27] Therefore, whenever an existing gas appliance (e.g., furnace, water heater, stove, dryer, grill, etc.) fails, its replacement will be more efficient and use less gas, resulting in lower NUPC.

Q. Have building codes changed as well?

A. Yes. New Hampshire has adopted the International Energy Conservation Code ("IECC"). Significant changes to New Hampshire's building code changes are as follows:

Table 5: New Hampshire Building Codes

New Hampshire Building Code Change History	
April 2010	2009 IECC adopted, with amendments
July 2007	2006 IECC adopted, with amendments
March 2002	Mandatory statewide building code is signed into law, using the 2000 IECC as reference, effective September 14th, 2002.

Q. How do these building code changes affect natural gas consumption?

A. Similar to the example provided in Table 4, changes in building codes has resulted in mandatory increases in R-value. Therefore, new buildings will be significantly more energy efficient. As old housing stock is replaced, average consumption (all else being equal) decreases.

[27] The National Appliance Energy Conservation Act of 1987, enacted March 17, 1987, and amended by the Energy Policy Act of 1992 and the Energy Policy Act of 2005.

Q. What are the economic and demographic effects on natural gas consumption?

A. I believe, based on preparing LDC demand forecasts, that the most significant economic factors that affected the Company's customer and NUPC trends include: (a) a dramatic spike in gas prices that started in 2005 caused by supply interruptions along the Gulf Coast; (b) equally dramatic decreases in gas prices since 2009, caused by a large increase in supply from shale formations in Pennsylvania and New York; (c) the economic recession that started in December 2007 and ended in June 2009[28]; and (d) the actual and forecasted long term price advantage that gas has over oil, caused by the large increase in gas supplies from shale formations. Some of these factors, such as the increased shale gas supply, have resulted in increased NUPC while other factors such as utility and customer-funded conservation, appliance efficiencies and building codes have contributed to declining NUPC.

To demonstrate the impact of gas prices on the Company's NUPC over the past several years, I have prepared Attachment GHT/DECPL-4, which shows the history of EnergyNorth's Residential Heating (Rate R-3) Cost of Gas ("COG") rates and the New York Mercantile Exchange ("NYMEX") futures settlement values. The significant decrease in COG rates since 2009 has likely had a positive effect on EnergyNorth's

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[28] Recessions are determined by the Business Cycle Dating Committee of the National Bureau of Economic Research. The following is excerpted from a report issued September 20, 2010 by the Business Cycle Dating Committee:

> The Business Cycle Dating Committee of the National Bureau of Economic Research … determined that a trough in business activity occurred in the U.S. economy in June 2009. The trough marks the end of the recession that began in December 2007 and the beginning of an expansion. … In determining that a trough occurred in June 2009, the committee did not conclude that economic conditions since that month have been favorable or that the economy has returned to operating at normal capacity. … The trough marks the end of the declining phase and the start of the rising phase of the business cycle. Economic activity is typically below normal in the early stages of an expansion, and it sometimes remains so well into the expansion.

NUPC during the years immediately following this price change.[29] The polar vortex winter of 2013-2014 had a detrimental impact on national gas prices, coupled with increased concern over capacity constraints in the New England region. As a result, EnergyNorth appropriately responded with COG rate increases during this period. Although these price increases were significant, they were not as severe or long-lasting as the price increases between 2005 and 2009.

I believe that the decrease in Residential NUPC was caused by customer conservation efforts in response to (a) the high gas prices in 2005 – 2006 and again in 2009, and (b) the great recession of 2007-2009, which reduced customers' incomes and wealth.[30] In addition, I believe that more stable and slower declining Residential NUPC since 2010 indicates that the increase in usage that would be caused by the recovery from the recession and the decrease in gas costs has been largely offset by the continuing impact of energy conservation.

Customer NUPC trends during this period have also been impacted by the difference in oil and gas prices. Table 6, below, demonstrates the competitive price advantage that natural gas has had over oil in recent years.

[29] That is, if EnergyNorth COG rates had been constant or increasing during this period rather than decreasing by at least 40 percent, the NUPC growth rates would have been lower than the actual growth rates that are summarized in Attachment GHT/DECPL-2.

[30] In response to the high gas prices, customers installed long term irreversible conservation measures, such as high efficiency gas heating and water heating equipment, energy efficient windows and doors, and increased insulation. Customers also implemented short term reversible conservation efforts, such as reducing temperatures in heated living and working spaces, or closing off parts of homes and buildings. In response to the recession, customers would likely be limited to implementing low-cost, reversible conservation efforts.

Table 6: Residential Delivered Cost of Heating Oil and Natural Gas

Residential Delivered Cost per Therm			
Year	Distillate Fuel Oil	Natural Gas	Oil / gas ratio
2005	$1.42	$1.47	0.970
2006	$1.65	$1.61	1.028
2007	$1.84	$1.63	1.129
2008	$2.33	$1.61	1.445
2009	$1.73	$1.48	1.165
2010	$1.95	$1.40	1.390
2011	$2.36	$1.42	1.670
2012	$2.71	$1.33	2.033
2013	$2.65	$1.34	1.971
2014	$2.58	$1.58	1.638
2015	$1.96	$1.03	1.903
2016	$1.54	$0.99	1.556
2017	$1.85	$1.06	1.745
2018	$2.04	$1.06	1.925
2019	$2.16	$1.07	2.019
2020	$2.21	$1.09	2.028
2021	$2.26	$1.10	2.055
2022	$2.29	$1.10	2.082
2023	$2.33	$1.11	2.099
2024	$2.36	$1.13	2.088
2025	$2.41	$1.14	2.114

2005 – 2014 data from the U.S. EIA Residential Sector Energy Price and Expenditure Estimates, (Table ET3). 2015 - 2025 values from EIA's Annual Energy Outlook 2017.

Given the above natural gas price advantage, existing natural gas customers that use oil for other household needs (e.g., hot water) would be motivated to replace such equipment with gas-fired appliances. Low-use residential customers replacing their oil furnace with a natural gas furnace would increase overall system usage, but may contribute to declining NUPC once they become heating (Rate R-3) customers, as their usage (with a new, efficient furnace) would be lower than the Rate R-3 class average.

Q. How would this oil-to-gas price spread impact C&I customers?

A. I believe that the increases in C&I customers and NUPC have likely been driven by the impact of (a) existing EnergyNorth C&I customers converting from oil to gas equipment to take advantage of the competitive advantage of gas over oil, and (b) new C&I customers also converting to gas equipment, especially on-the-main energy users.

Finally, although overall NUPC has remained relatively flat since 2005, volatility has begun to increase. I believe this increased volatility is a reaction to shorter duration, less severe price spikes over the past three winters. If this trend continues and the price spikes become longer and more severe, NUPC will likely decline.

Q. Please describe how demographics can play a role in NUPC.

A. Demographics can influence NUPC at the individual premise level when more or fewer people occupy the premise. Additionally, premise vacancy rates caused by shifts in population also may affect use per customer[31]. The State of New Hampshire's August 2013 report[32] on the state's economic health recognizes the importance of demographics in the State's economic recovery. In the report, it was recognized that population growth in New Hampshire lags the nation:

> "Population changes may affect New Hampshire job growth and how job needs are met. From 2008 to 2012, the nation's population grew by 3.2 percent, compared to 0.4 percent for New Hampshire. This slower growth was primarily caused by domestic outmigration. A low rate of population growth

[31] Assuming that the premise retains an active gas account for minimal space heating, for example.
[32] "Measuring New Hampshire's Economic Health: A Workforce Perspective", published by the New Hampshire Employment Security, Economic and Labor Market Information Bureau, August 2013.

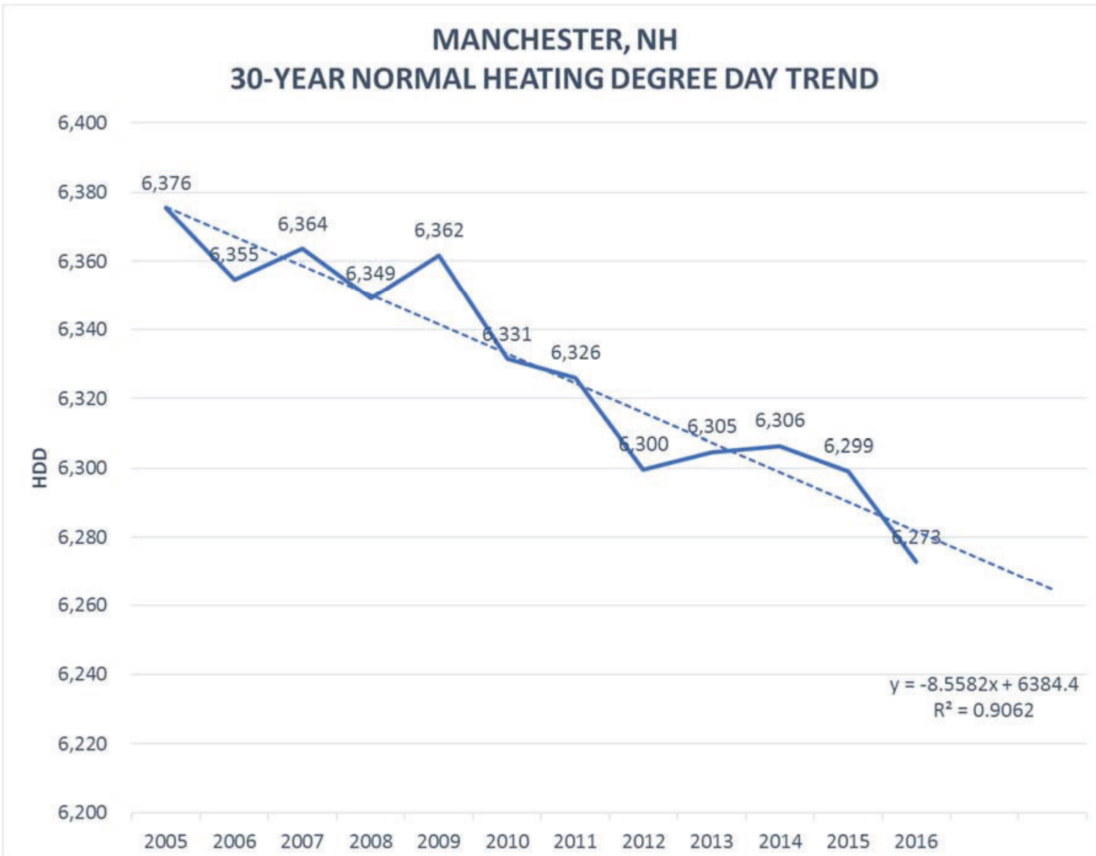
> will affect the rate of job growth in the future, as well as the distribution of jobs by industry and occupation."

Although the above quotation is addressing the issue of employment, it clearly speaks to the trend in New Hampshire's population growth, which can have a direct impact on NUPC, particularly in the Residential classes.

Q. The Company's proposed decoupling mechanism will symmetrically adjust for weather deviations from EnergyNorth's 30-year normal degree day standard. Are there other weather-related reasons to implement decoupling?

A. Yes. Normal temperature, defined in New Hampshire as the latest 30-year average heating degree days, has been declining. The trend over the past decade is for warmer years (most recent) to replace colder years (oldest of the 30-years). This is demonstrated as follows:

Table 7: 30-Year Normal Degree Day History



As the above graph shows, annual normal degree days has declined 103 heating degree-days ("HDD") since 2005. Even under "normal" weather conditions, it is reasonable to assume future year allowed revenues will be deficient if this warming trend continues.

4. Summary and Conclusion

Q. Please summarize why EnergyNorth is proposing, and should be granted, a decoupling mechanism.

A. The EERS Settlement Agreement states that each of the utilities in the state shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM. The Company's preferred solution is decoupling. Further, decoupling is now a mainstream ratemaking tool for gas LDCs across the country. 67 LDCs in 29 different states have a form of decoupling, with the clear majority utilizing actual revenues. EnergyNorth's proposed structure, detailed in Section V below, follows this nationally preferred and accepted design.

Decoupling further solves a long-standing ratemaking issue. There are clear declining NUPC trends in EnergyNorth's largest, most homogeneous customer classes (e.g., Residential Heating) that impact the Company's ability to earn its allowed rate of return. The factors contributing to this declining use reach well beyond utility-funded programs. The data and analysis presented in section IV.D above detail the main contributors to declining NUPC, including: customer-funded conservation; stricter appliance efficiency and building codes; economic and demographic drivers; and a warmer weather trend. None of these factors are within the control of the Company, and the Company should not be penalized between general rate cases for these exogenous events. Decoupling frees EnergyNorth from the negative effects of these causes of declining NUPC, and enables unfettered support and promotion of the State's energy efficiency goals.

V. ENERGYNORTH'S DECOUPLING PROPOSAL

A. Details of EnergyNorth's Proposed Decoupling Mechanism

1. Introduction

Q. Please provide a general description of the decoupling mechanism that EnergyNorth is proposing.

A. The Company is proposing a RPC decoupling mechanism that will be applied to all customers in all firm tariffed rate classes. The proposed RDM provides for separate winter and summer rate adjustments that correspond to the seasonality of the Company's distribution rates and Cost of Gas clause.

Q. Please list the RDM components that define EnergyNorth's proposed RDM.

A. EnergyNorth's proposed RDM is defined by the following RDM design components:

1) Basis for the true up calculation;
2) Rate classes to be included in the RDM;
3) Rate classes to be included in separate true-up customer groups;
4) Approach for returning RDM revenue surplus or recovering revenue shortfall from customers;
5) Frequency and timing of RDM rate adjustment filing;
6) Adjustments to Actual and Target revenues;
7) Treatment of new customers; and
8) Customer impact protections.

I will describe, explain and support these components of the Company's proposed RDM in the following sections of my testimony.

2. Basis for the true up calculation

Q. Please explain the approach that the Company is proposing for the true up calculation.

A. As described earlier in my testimony, the Company's proposed decoupling mechanism is a RPC RDM. A RPC RDM is critical to providing the Company with some opportunity to earn a reasonable return between rate cases, and retain revenues related to the growth in customers. Our RDM research indicates that RPC decoupling mechanisms are most common for gas LDCs because LDCs are experiencing significant customer growth that is related to the strong economic incentives for conversion from oil to gas. A RPC decoupling mechanism provides growth in revenues to partially offset the costs to connect the new customers.

3. Rate classes to be included in the RDM

Q. Which rate classes will be included in the Company's proposed RDM?

A. EnergyNorth proposes to include all firm tariffed customer classes in the RDM true up calculations, and to apply RDM rate adjustments to all firm rate classes.

It is appropriate to apply the RDM to all customers because (a) all EnergyNorth firm customers are eligible for the Company's EE programs and (b) Residential and C&I customers are likely to implement conservation efforts that are not directly associated with EnergyNorth's EE programs.

The RDM will not be applied to special contract customers because special contract customers are not eligible for EE programs, and special contract customers are not charged other rate adjustments, such as the LDAC.

4. True up Customer Groups

Q. How will the Company's customers be grouped for purposes of administering the proposed RDM?

A. The Company's firm rate classes will be combined into RDM Customer Groups as shown in Table 8 below:

Table 8: RDM Customer Groups

RDM Customer Group	Firm Rate Classes
Residential Non-Heating	R-1
Residential Heating	R-3, R-4
Commercial and Industrial	G-41, G-42, G-43, G-51, G-52, G-53, G-54

Q. Please explain why you are proposing to combine rate classes into the three rate groups that you have listed in Table 8, rather than keeping each C&I rate class separate?

A. I am not proposing to keep each rate class separate because C&I customers are assigned to the C&I rate classes based on their annual usage and percent of their annual usage that occurs in the Winter period. The potential shifting of C&I customers between rate classes may cause unintended results in the RDM calculations; these unintended results are avoided if all C&I customers are included in the same RDM customer group. In addition, I have prepared Attachment GHT/DECPL-5 to provide a summary of the variability in normal revenue per customer for each of the C&I rate classes[33]. Attachment GHT/DECPL-5 demonstrates that there is significant year-to-year variability in normal revenue per customer for several C&I rate classes, especially the large use classes G-42, G-43 and G-53. If the Company's RDM provided for separate revenue true ups and separate RDM rate adjustments for each C&I rate class, the calculation of the seasonal revenue shortfall/surplus would be significantly affected by whether the target RPC for that rate class had been determined in an "up" year or a "down" year. Separate RDM rate adjustments for each C&I rate class would likely result in noticeable rate volatility for some C&I rate classes.

This potential volatility is avoided with a single RDM true up calculation for all C&I rate classes combined. Attachment GHT/DECPL-5 also demonstrates that the normal revenue per customer for all C&I rate classes combined is relatively stable. Thus, the seasonal calculated revenue shortfall or surplus for the combined C&I RDM customer group will not be affected by the year (i.e. the rate case test year) that is used to determine the target RPC.

5. Frequency and timing of RDM rate adjustment filing

Q. Please explain how often and when the RDM rate adjustments will be made.

A. The Company will calculate separate Winter and Summer season RDM rate adjustments based on the prior winter or summer season RDM revenue shortfalls or surpluses, for

[33] This analysis is based on the same actual and weather normalized billing determinant data that was used to prepare Attachment GHT/DECPL-7; monthly revenues are based on 2016 rates, and R-4 revenues are calculated at R-3 rates. Additional discussion of the decoupling data base and analysis is provided in Section V.10.

each RDM customer group. Separate seasonal RDMs would reduce the shifting of charges or credits (associated with RDM revenue shortfalls or surpluses) between temperature sensitive and non-temperature sensitive customers.

6. Adjustments to Target and Actual revenues

Q. Please explain how the RDM Target Revenue per Customer will be determined.

A. The initial Winter and Summer RDM Target Revenue per Customer will be set in this proceeding; the target RPCs for each RDM customer group and for each season will be calculated in the Company's compliance filing by summing the allowed revenues by season for each RDM customer group, divided by the seasonal average number of RDM customer group customers.

For each seasonal RDM filing, the RDM target RPCs will be adjusted to account for the rates that were in effect during the recently-completed RDM season, because the Company's base distribution rates are adjusted annually, effective every July 1 to reflect the CIBS rate adjustment. The derivation of the Target Revenue per Customer by RDM Rate Group, based on the Company's proposed rates, is included as Attachment GHT/DECPL-9.

Q. Please explain how actual revenues per customer will be calculated.

A. Winter and Summer Actual Revenues per Customer, by RDM Rate Group, will be calculated directly from the actual booked base distribution revenues and actual booked number of average customers. The Company will calculate the RDM Actual Revenues per Customer and the RDM revenue shortfall/surplus monthly on a calendar month basis.

At the end of each season, the Company will sum all of the monthly data and will calculate RPC on a seasonal basis.

7. Treatment of new customers

Q. How will new customers be treated in the Company's proposed RDM?

A. The Company will include new, non-expansion rate customers in the RDM calculations. These customers will be charged the rate adjustments associated with the RDM and the calculations of actual revenues per customer will include the new customers. The Company proposes that expansion rate new customers be excluded from the RDM calculation and not be charged or credited the RDM rate. The reason for this proposed exclusion is that the expansion rates include a higher delivery rate than existing or new (non-expansion) customer rates. For example, expansion rate R-6 (Residential Heating - Expansion) delivery rates are 30% higher than existing R-3 Residential Heating rates. If R-3 and R-6 customers were included in the same RDM customer group, then the revenues associated with the 30% R-6 delivery premium, all else being equal, would be returned to all customers through the RDM. This defeats the purpose of the expansion rates, whereby the delivery premium revenue supports the incremental costs of the expansion investment.

An alternative treatment that creates a separate RDM customer group for expansion customers is not appropriate. Currently there are no expansion rate customers. Therefore, the near-term population of expansion rate customers will be small and would likely result in an unstable RDM calculation. For these reasons the Company proposes to exclude expansion rate customers from the RDM until they are migrated into the existing rate schedules once their expansion term expires.

8. Customer impact protections

Q. Is EnergyNorth proposing a customer impact cap on the annual RDM adjustments?

A. Yes. The Company's proposed RDM includes a plus or minus 5 percent cap on rate changes; that is, the RDM increase or decrease to rates will be limited to 5 percent of distribution revenues (revenues that exclude charges for COG and LDAC revenues, and all other related charges). Any excess over the 5 percent upper or lower limit will be deferred for recovery in the next period with carrying charges at the prime lending rate. The proposed 5 percent customer impact cap, based on distribution rates, is approximately equivalent to a 2.5 percent increase in total bills.[34]

Lastly, the proposed RDM includes a provision that the Company will file for a mid-period adjustment if the projected RDM end of season under or over collection exceeds 10 percent of total projected seasonal distribution revenues.

9. Summary

Q. To summarize, please describe how the Company's proposed RDM will be calculated and applied.

A. As a general summary of my testimony in this section, summer and winter RDM adjustments will be determined prior to the start of each season by (1) calculating Target

[34] The percent increase based on all charges, including COG and LDAC rates in addition to distribution rates, will depend on the level of the COG and LDAC rates at any time.

Revenue[35] per customer for that season for each RDM Rate Group; (2) calculating actual revenue per customer for that season (i.e. the most recently completed season) for each RDM Rate Group; (3) calculating the difference between Target and actual revenue per customer; (4) calculating RDM Rate Group revenue shortfalls or surpluses by multiplying the revenue per customer differences times actual average monthly customers for each rate group; (5) calculating the Company total revenue shortfall or surplus by summing the RDM Rate Group revenue shortfalls or surpluses; and lastly (6) calculating the RDM adjustment by dividing the Company total revenue shortfall or surplus by projected therm deliveries for the upcoming season.

This adjustment will also include a reconciliation of the same season prior period authorized Company total revenue shortfall or surplus to actual revenues recovered or returned in the same season prior period.

10. Additional RDM details

Q. Have you prepared a schedule to illustrate how the RDM calculations would be made?

A. Yes, I have prepared Attachments GHT/DECPL-6 and GHT/DECPL-7 for that purpose. To prepare this hypothetical illustration I used actual Company data for the period from January 2010 - 2016 to show:

[35] The summer and winter Target Revenue per customer for each rate group will be determined from the revenue requirement approved in this proceeding.

The calculation of the Target RPC for the three customer groups (Residential Heating, Residential Non-Heating, and C&I). I developed the Target RPC for a 2010 Test Year, which is shown in Attachment GHT/DECPL-6.

The calculation of actual RPCs, RDM revenue shortfalls or surpluses per customer, and total revenue shortfalls or surpluses for Summer 2011 through Summer 2016, which is shown in Attachment GHT/DECPL-7.

The hypothetical calculations for all years (2010-2016) utilize 2016 rates.

Q. Please summarize the results of the analysis that is provided in Attachment GHT/DECPL-9.

A. I have prepared Table 9,[36] below, to summarize the revenue shortfalls, by season, from Summer 2011 through Summer 2016:

[36] Please see Attachment GHT/DECPL-7 for supporting calculations. Also, Table 10 below provides further explanatory information regarding these hypothetical results.

Table 9: RDM Class Accrual Analysis

	Accrued Revenue Shortfall (Surplus) $			
	R-1	R-3, R-4	C&I	Total
Summer 2011	$763	$207,719	$15,778	$224,260
Winter 2011 - 2012	$3,978	$2,233,390	$1,732,447	$3,969,815
Summer 2012	$1,846	$373,048	$71,814	$446,707
Winter 2012 - 2013	-$15,033	$346,231	-$175,192	$156,005
Summer 2013	-$592	$288,368	-$124,816	$162,960
Winter 2013 - 2014	-$45,365	-$1,469,303	-$1,964,463	-$3,479,131
Summer 2014	-$687	$175,820	-$500,720	-$325,587
Winter 2014 - 2015	-$3,697	-$910,895	-$1,847,245	-$2,761,837
Summer 2015	$3,499	$356,979	-$421,197	-$60,720
Winter 2015 - 2016	$5,915	$2,509,631	$1,171,639	$3,687,184
Summer 2016	$3,656	$381,248	-$299,262	$85,642

[1] Utilizing a 2010 base year and billing determinants and 2016 billing rates.

Q. How will the seasonal revenue shortfalls or surpluses be billed to customers?

A. As described above, a singular rate per therm will be calculated each season based on the sum of the accrued class RDMs, and billed the subsequent matching season. For example, the Summer 2011 total accrued shortfall of $224,260 will be collected over the 2012 summer period. The rate per therm will be calculated on a total system basis and applied to all firm rate classes.

These accrued seasonal totals must first pass the 5% test prior to calculating the billing rate per therm. If the RDM accrual is a shortfall and exceeds 5% of total distribution revenues for that season, then the dollars in excess of 5% will be deferred for recovery until the next applicable season. For example, the Winter 2011/2012 total RDM value exceeded 5%; therefore, the excess dollars would have been deferred until the following

2012/2013 winter period. The 5% test applies to the sum of the calculated RDM and deferred RDM for the applicable period. This may result in deferred dollars not being collected for multiple seasons, if the RDM continues to yield a surcharge in excess of the 5% limit. However, the Company's proposal includes a provision whereby if the calculated RDM exceeds 10%, the Company may petition the Commission for a more immediate recovery of the RDM dollars in excess of 10%.

Based on the sample data, the billing of the calculated seasonal RDMs is as follows:

Table 10: Seasonal RDM Accruals, Deferrals, and Billing Rates

Hypothetical RDM

	Accrued Revenue Shortfall (Surplus) $				+/- 5.0% Limit Test		Billable Amounts		
Season	R-1	R-3, R-4	C&I	Seasonal Accrued Total	klokoshjlzih	Deferral	Adjusted Total	Adjusted % of distribution revenues	Rate Per Therm
Summer 2011	$763	$207,719	$15,778	$224,260	1.0%	$0	Billing Lag		
Winter 2011 - 2012	$3,978	$2,233,390	$1,732,447	$3,969,815	9.8%	$1,937,300			
Summer 2012	$1,846	$373,048	$71,814	$446,707	2.1%	$0	$224,260	1.0%	$0.0061
Winter 2012 - 2013	-$15,033	$346,231	-$175,192	$156,005	0.3%	$0	$2,032,515	5.0%	$0.0178
Summer 2013	-$592	$288,368	-$124,816	$162,960	0.7%	$0	$446,707	2.1%	$0.0113
Winter 2013 - 2014	-$45,365	-$1,469,303	-$1,964,463	-$3,479,131	-7.1%	-$1,022,620	$2,093,305	4.7%	$0.0180
Summer 2014	-$687	$175,820	-$500,720	-$325,587	-1.4%	$0	$162,960	0.7%	$0.0042
Winter 2014 - 2015	-$3,697	-$910,895	-$1,847,245	-$2,761,837	-5.5%	-$1,261,730	-$2,456,511	-5.0%	($0.0207)
Summer 2015	$3,499	$356,979	-$421,197	-$60,720	-0.3%	$0	-$325,587	-1.4%	($0.0075)
Winter 2015 - 2016	$5,915	$2,509,631	$1,171,639	$3,687,184	8.4%	$240,762	-$2,522,728	-5.0%	($0.0211)
Summer 2016	$3,656	$381,248	-$299,262	$85,642	0.4%	$0	-$60,720	-0.3%	($0.0014)
Winter 2016 - 2017							$2,184,693	5.0%	$0.0180
Summer 2017							$85,642	0.4%	$0.0021
					Outstanding Deferrals	Winter	$240,762		
						Summer	$0		
Based on a 2010 base year and billing determinants, and 2016 billing rates.									

The results of the above calculations are shown graphically below:

Chart 2a: Cumulative Effect of RDM - Summer

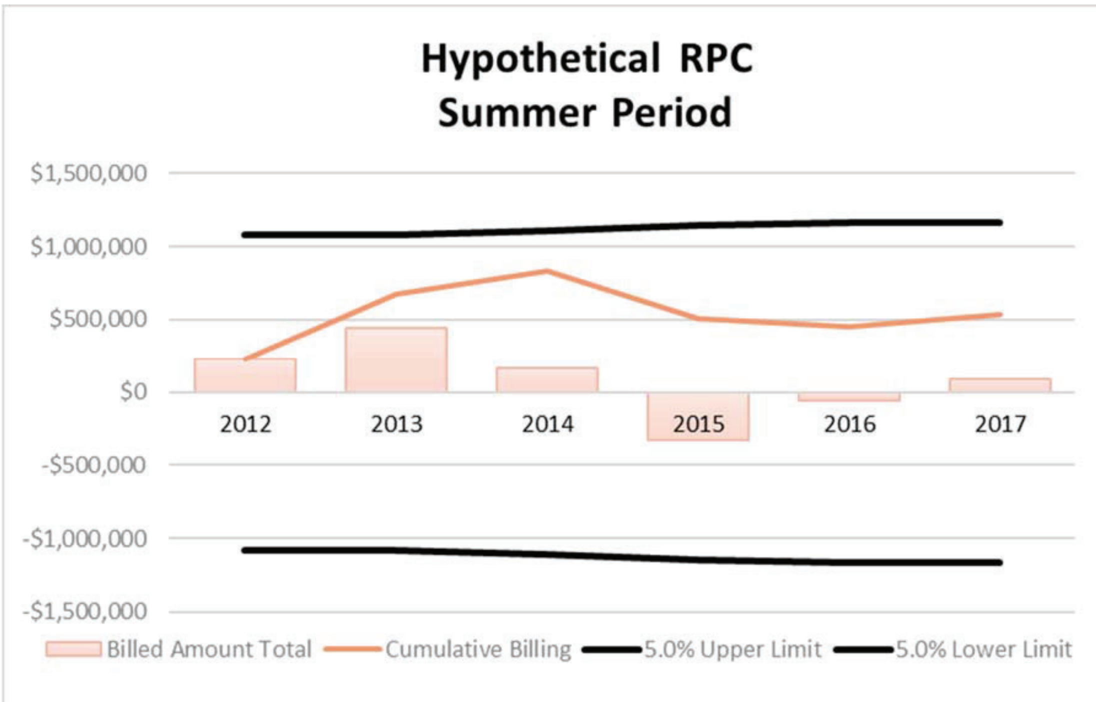
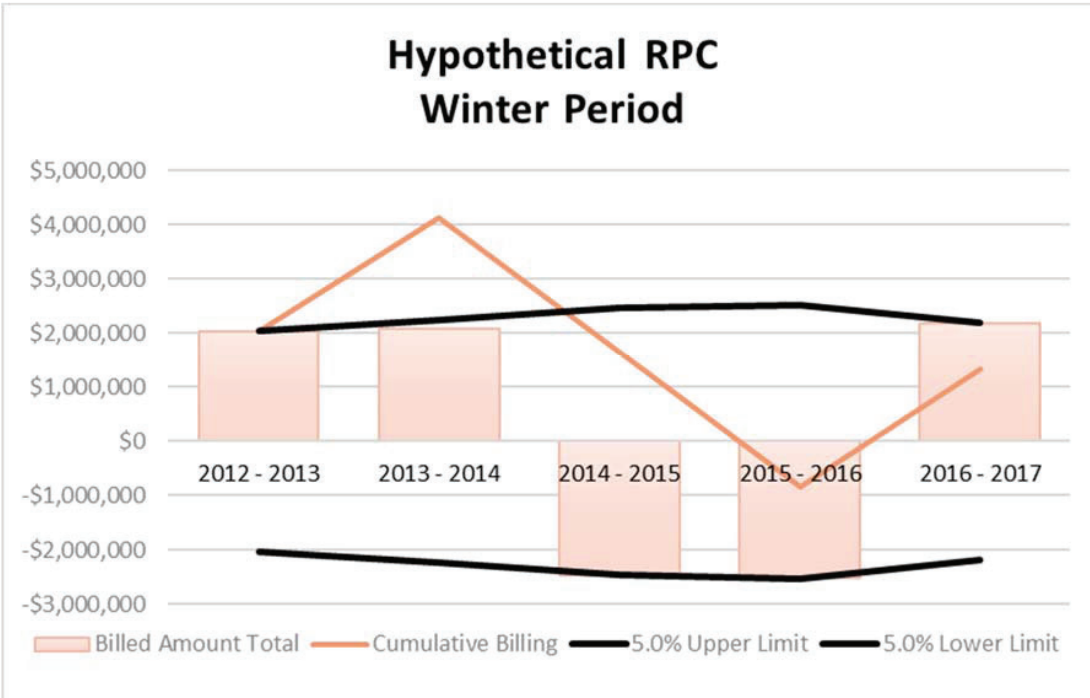


Chart 2b: Cumulative Effect of RDM - Winter



Tables 9 and 10 demonstrate that if an RDM had been in effect during this period, the RDM rate accrual would have been a debit (charge) in 5 seasons and a credit in the other 6 seasons. The largest shortfall is $3,969,815, or 9.8% of distribution revenues and the largest surplus is -$3,479,131, or 7.1% of distribution revenues. On a cumulative basis, the five-year cumulative RDM shortfall would have been $2,105,298; or 0.6% of total distribution revenues.

On a billed basis, the RDM rate adjustments would have been generally small. Seven of the seasons would have resulted in a charge to customer bills, and four seasons would have been credits. The 5 percent customer impact cap would have been applied in two of the five winter seasons, to be recovered in following winter periods. The 5 percent cap would not have been exceeded in any of the six summer periods. Lastly, there is a hypothetical shortfall to be collected in the Winter 2017 – 2018.

Q. Please describe the timing of RDM calculations, filings, and rate adjustments.

A. I have prepared Attachment GHT/DECPL-8 to illustrate the timing of RDM calculations, filings, and rate adjustments. Referring to Attachment GHT/DECPL-8, the Winter or Summer RDM Adjustment Factor will be based on the calculations related to the most recently completed corresponding Winter or Summer RDM prior period. The Company proposes to make its Winter RDM filing together with its annual LDAC filing, on or before September 1 of each year and each Summer RDM filing will be made on or before March 1 of each year. Each Winter and Summer RDM filing will also include a final reconciliation of actual and allowed RDM revenues for the prior same period.

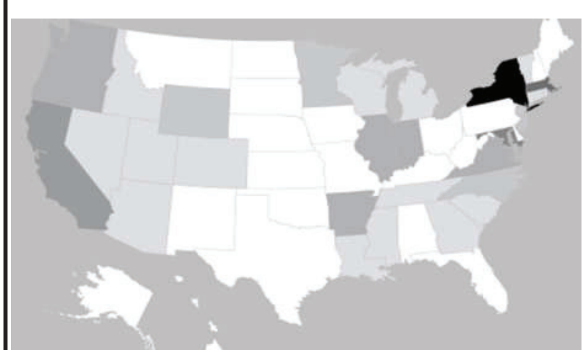
Q. Has the Company prepared an RDM tariff provision?

A. Yes. The Company's proposed Local Distribution Adjustment Clause ("LDAC"), which includes provisions for the RDM in Section 18(C.1) of the LDAC, is included in the proposed tariff in this proceeding. Section 18(C.1) describes the manner in which the Company proposes to annually true up Actual Revenues versus Target Revenues, and to recover the RDM Adjustment Factors through rates. Section 18(C.1) also describes the documentation that the Company will provide with annual RDM filings. This new RDM language replaces the current "Lost Revenue Adjustment Mechanism Allowable for LDAC" provisions, as the proposed RDM replaces the LRAM in its entirety.

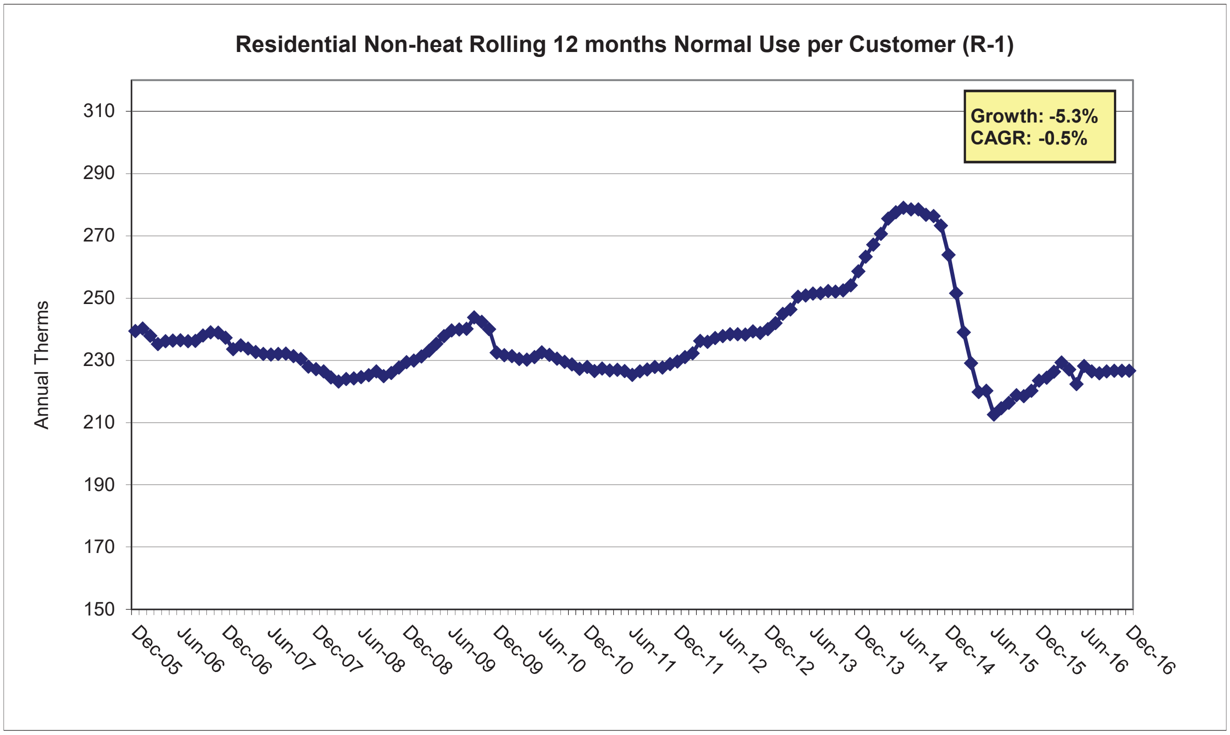
Q. Does this complete your testimony?

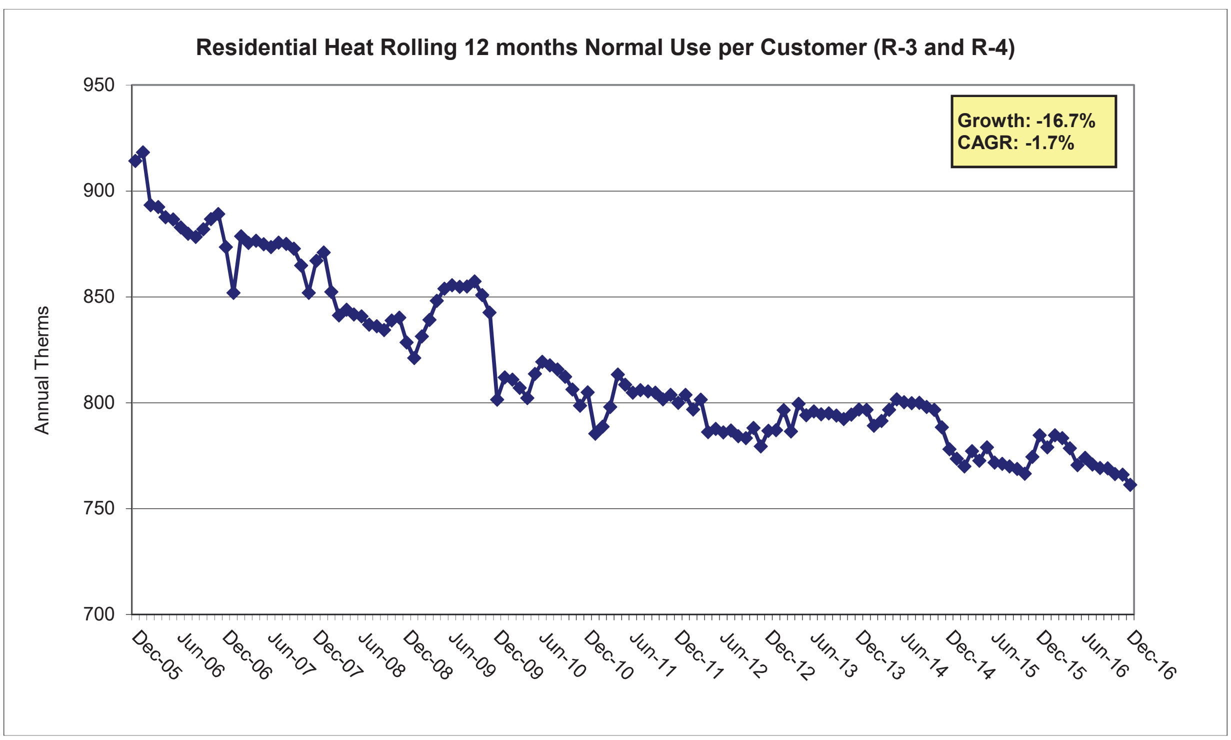
A. Yes, it does.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
U.S. LDCs with Decoupling Mechanisms

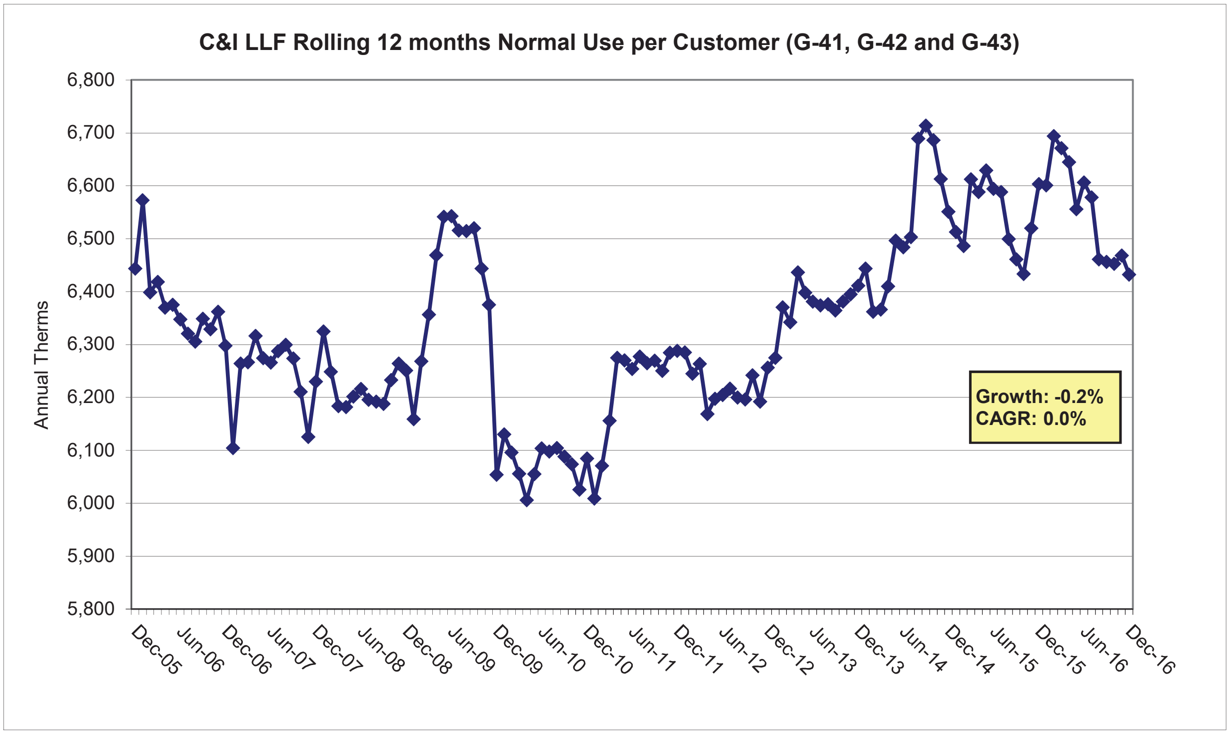
Northeast	Midwest
CT	**IL**
Connecticut Natural Gas Corporation	Ameren Illinois Company
MA	North Shore Gas Company
Bay State Gas Company	Peoples Gas Light and Coke Company
Boston Gas Company	**IN**
Colonial Gas Company	Citizens Energy Group
Fitchburg Gas & Electric	Indiana Gas Company, Inc.
Liberty Utilities (New England Natural Gas Company) Corp.	Southern Indiana Gas and Electric Company, Inc.
NSTAR Gas Company	**MI**
NJ	Michigan Gas Utilities Corporation
New Jersey Natural Gas Company	**MN**
South Jersey Gas Company	CenterPoint Energy - MN
NY	Minnesota Energy Resources Corporation
Brooklyn Union Gas Company	**WI**
Central Hudson Gas & Electric Corporation	Wisconsin Public Service Corporation
Consolidated Edison Company of New York, Inc.	**West**
Corning Natural Gas Corporation	**AZ**
KeySpan Gas East Corporation	Southwest Gas Corporation
National Fuel Gas Distribution Corporation	**CA**
New York State Electric & Gas Corporation	Pacific Gas and Electric Company
Niagara Mohawk Power Corporation	San Diego Gas & Electric Co.
Orange and Rockland Utilities, Inc.	Southern California Gas Company
Rochester Gas and Electric Corporation	Southwest Gas Corporation
St. Lawrence Gas Company, Inc.	**CO**
RI	Public Service Company of Colorado
Rhode Island Gas & Electricity (National Grid-RI)	**ID**
VT	Avista Gas
Vermont Gas Systems, Inc.	**NV**
South	Southwest Gas Corporation
AR	**OR**
Arkansas Oklahoma Gas Corp.	Avista Utilities
Black Hills Energy Arkansas, Inc.	Cascade Natural Gas Corporation
CenterPoint Arkansas	Northwest Natural Gas Company
GA	**UT**
Atlanta Gas Light Company	Questar Gas Company
LA	**WA**
Atmos - LA	Avista Corporation
MD	Cascade Natural Gas Corporation
Baltimore Gas and Electric Company	Puget Sound Energy, Inc.
Chesapeake Utilities - Maryland	**WY**
Columbia Gas of Maryland	Black Hills Northwest Wyoming Gas Utility Company, LLC
Sandpiper Energy	Questar Gas - WY
Washington Gas Light (WGL)	
MS	
Atmos - Mississippi	
NC	
Piedmont Natural Gas Company, Inc.	
Public Service Company of North Carolina, Incorporated	
SC	
Piedmont Natural Gas Company - SC	
TN	
Chattanooga Gas Company	
VA	
Columbia Gas of Virginia, Incorporated	
Virginia Natural Gas, Inc.	
Washington Gas Light	

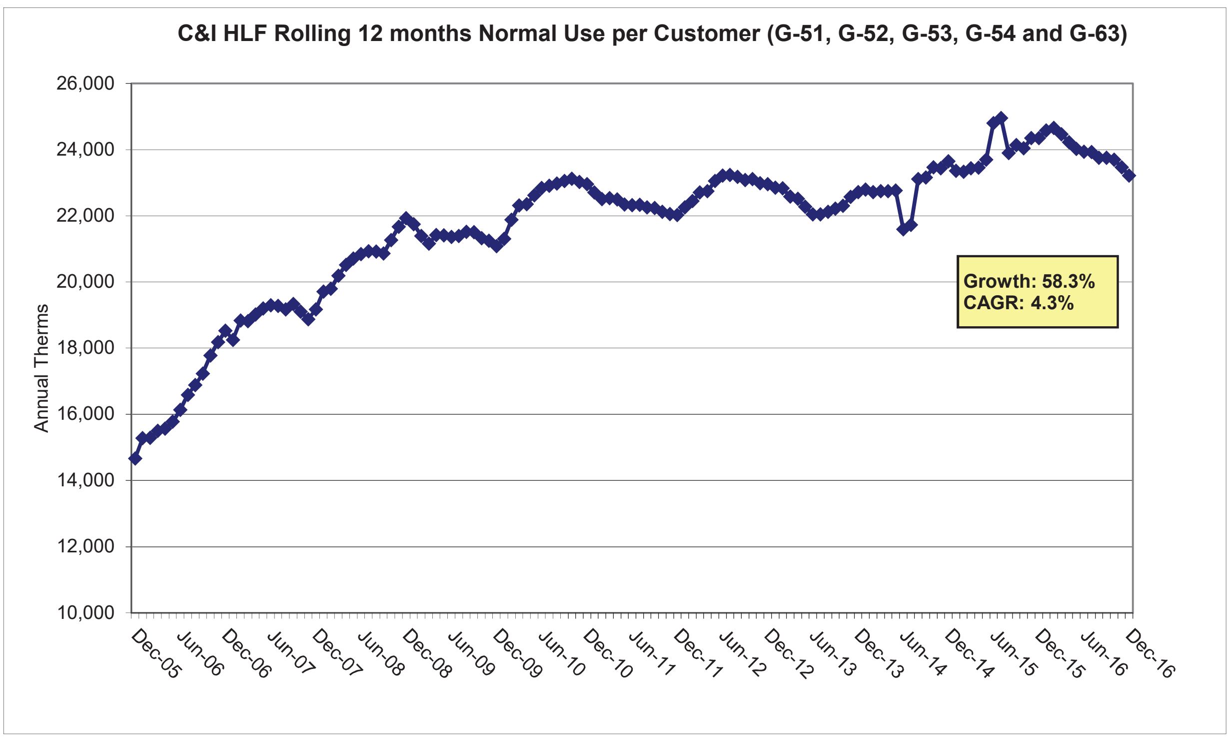
Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Normalized Use per Customer, 2005 – 2016



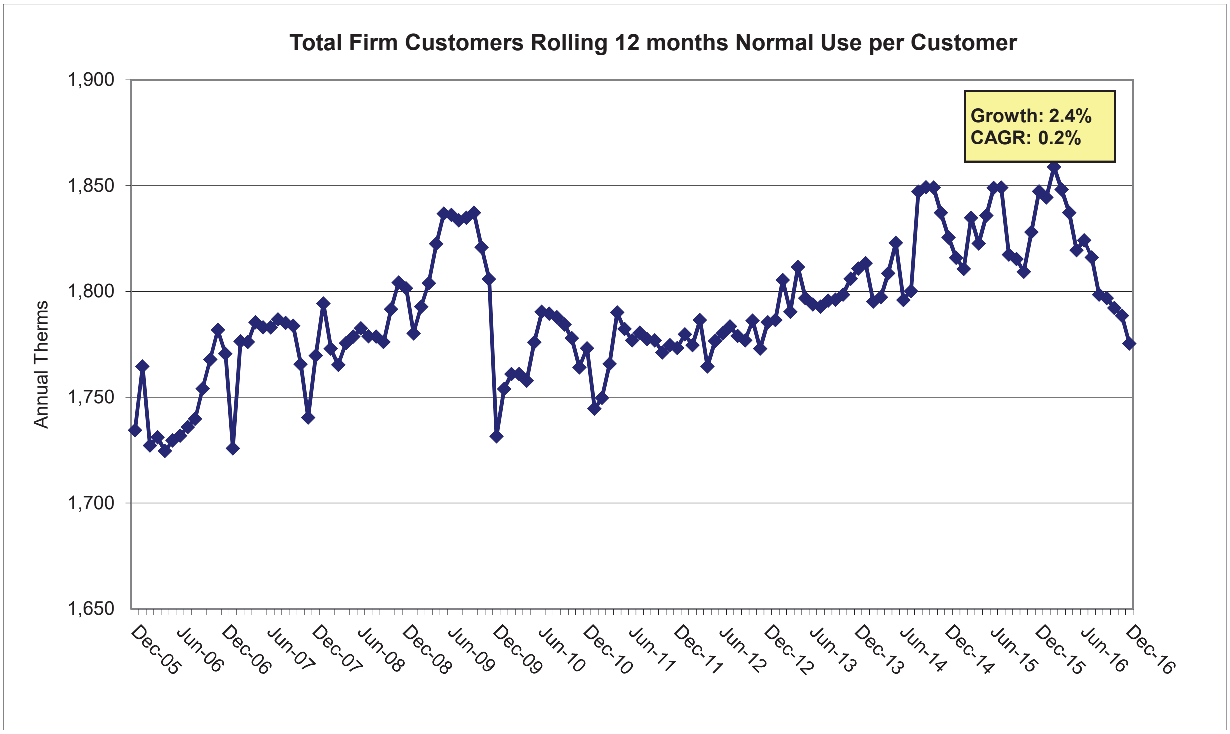


Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Normalized Use per Customer, 2005 – 2016

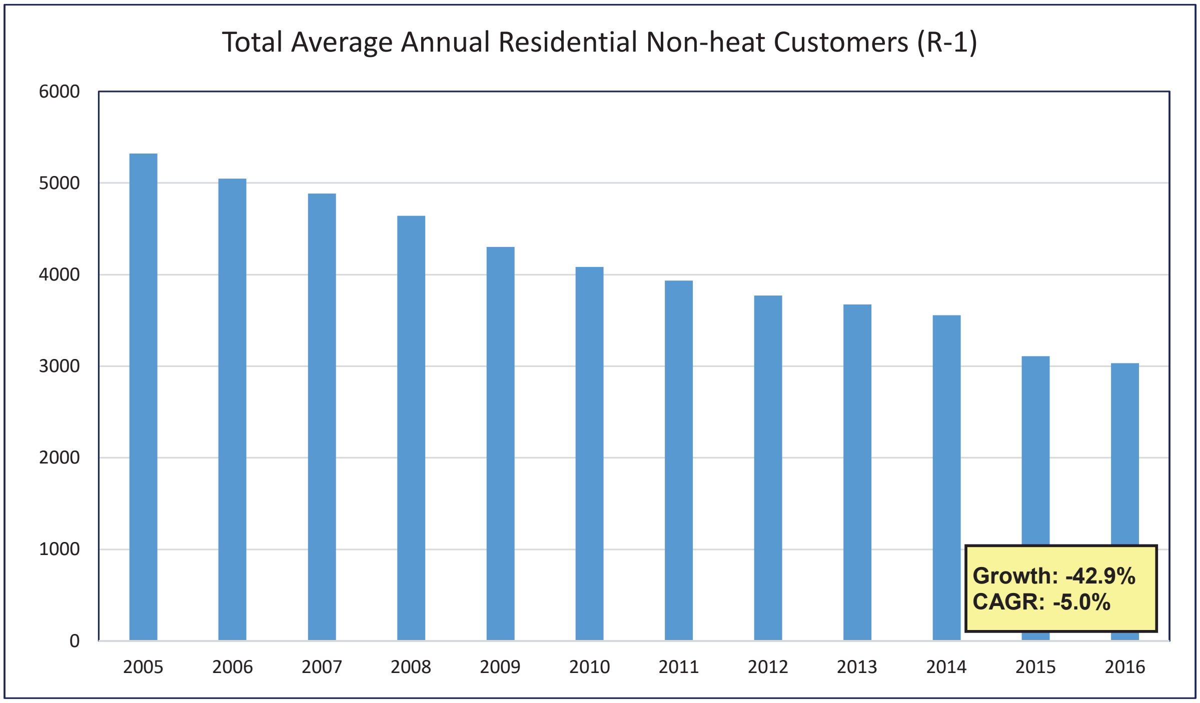


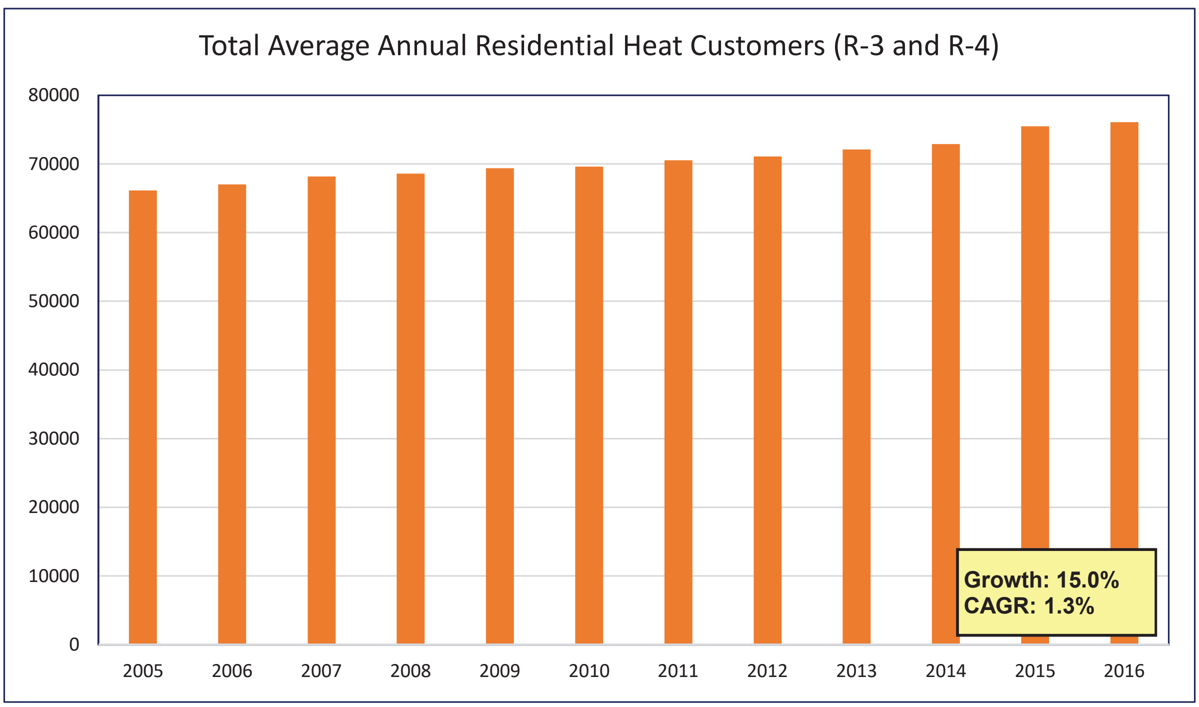


Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Normalized Use per Customer, 2005 – 2016

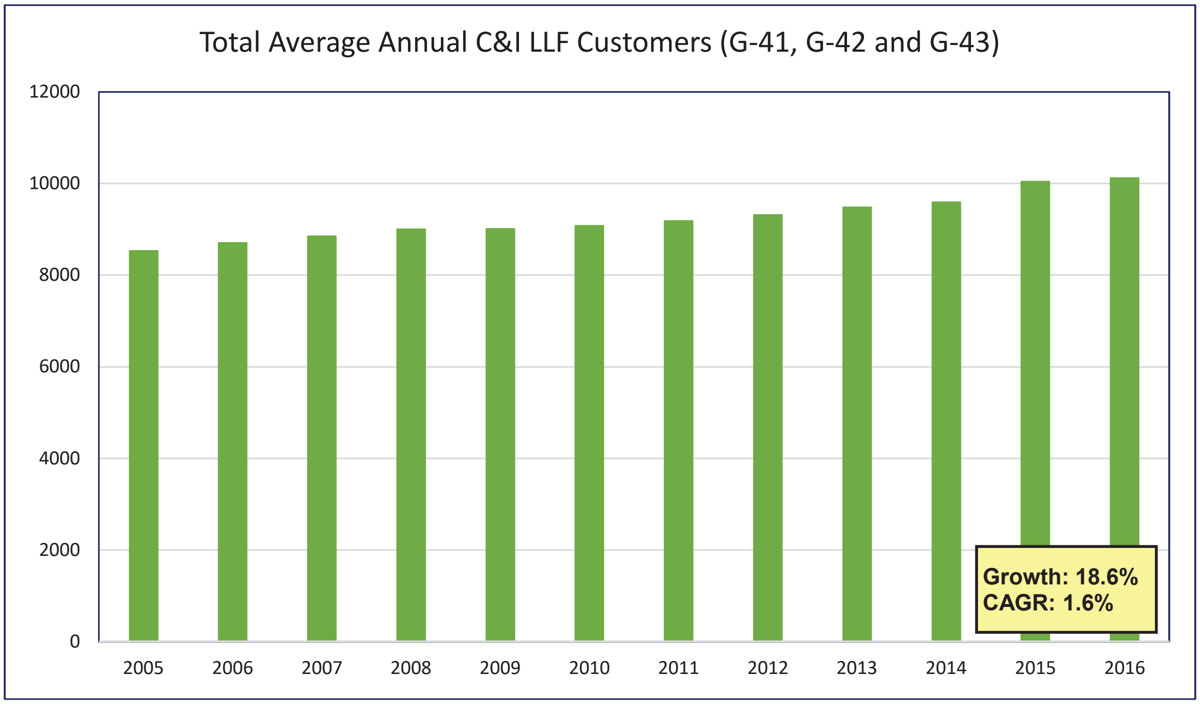


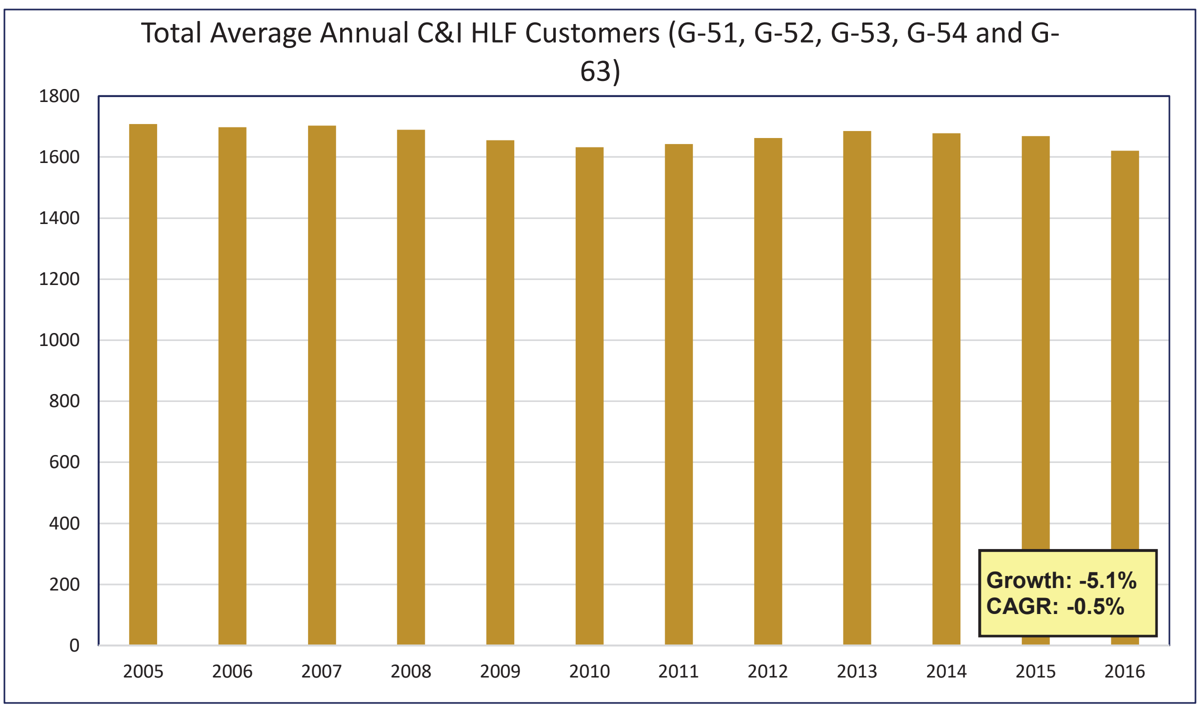
Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Customers, 2005 – 2016



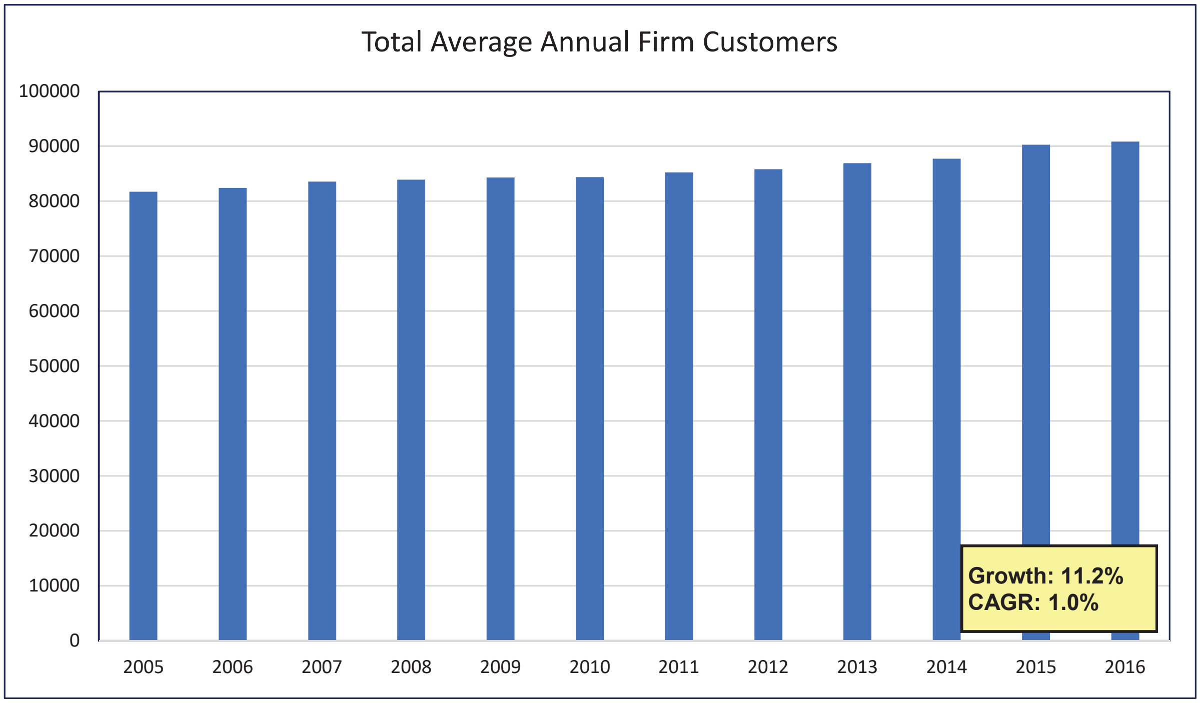


Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Customers, 2005 – 2016

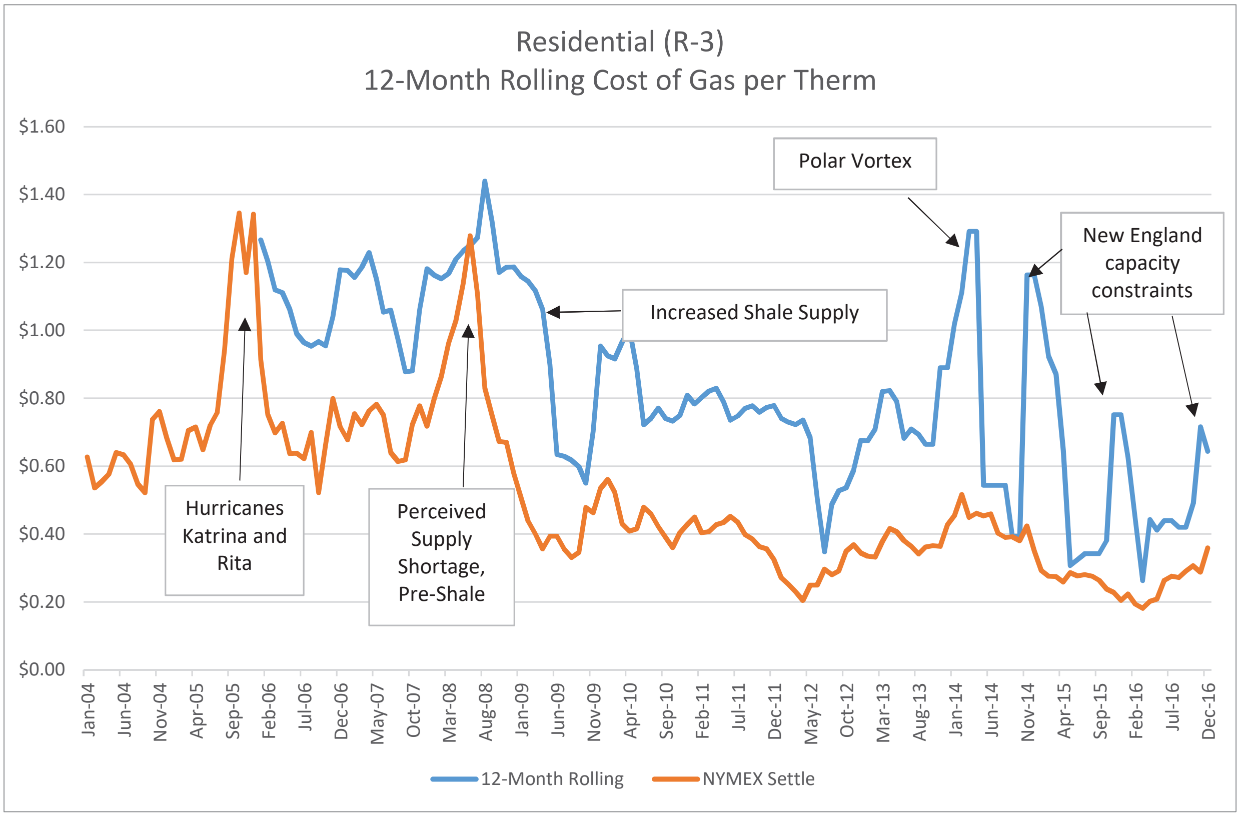




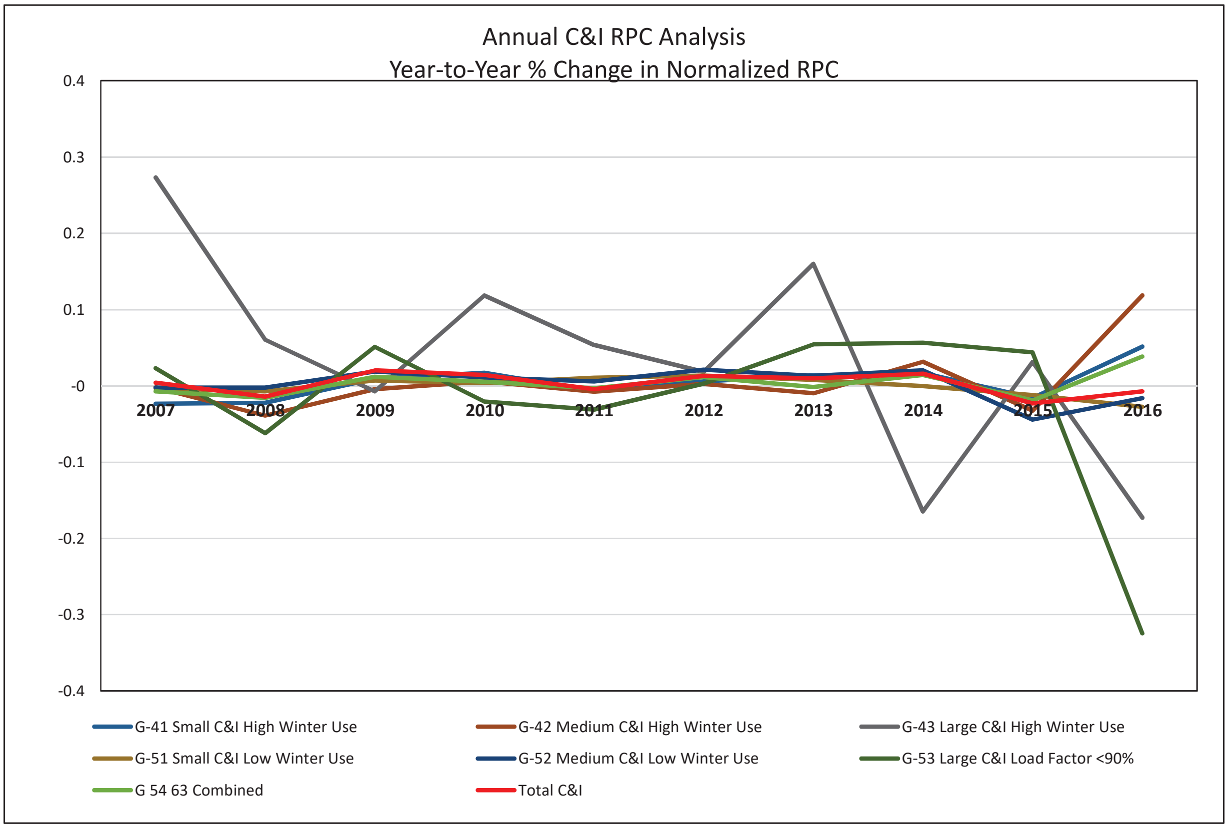
Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Customers, 2005 – 2016



Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth 12-Month Rolling R-3 Unit Cost of Gas, 2006 – 2016



Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Year-to-Year C Revenue Per Customer



Liberty Utilities (EnergyNorth Natural Gas) Corp.
Hypothetical RDM Target Revenues: 2010 Billing Determinants, 2016 rates

Line	Class		2010 Base Rate Revenues at 2016 rates		Average Customers		Target Revenue per Customer	
			Winter	Summer	Winter	Summer	Winter	Summer
1			(A)	(B)	(C)	(D)	(E)	(F)
2	Residential Non-heat	R-1	$499,480	$435,831	4,103	4,060	**$121.73**	**$107.34**
3	Residential Heat	R-3, R-4	$24,336,541	$12,789,369	70,111	69,146	**$347.12**	**$184.96**
4	Total Residential		$24,336,541	$12,789,369	70,111	69,146		
5	Small, High Winter Use	G-41	$6,836,739	$2,931,513	7,697	7,382		
6	Medium, High Winter Us	G-42	$8,189,424	$2,927,026	1,503	1,490		
7	Large High Winter Use	G-43	$1,077,990	$419,234	42	40		
8	Total High Winter Use		$ 16,104,153	$ 6,277,773	9,242	8,912		
9	Small, Low Winter Use	G-51	$791,325	$592,542	1,282	1,249		
10	Medium, Low Winter Us	G-52	$909,699	$597,965	311	309		
11	Large Low Winter Use	G-53	$745,035	$462,344	37	36		
12	Large Use, LF >90%	G-54	$456,463	$361,789	21	20		
13	Total Low Winter Use		$2,902,522	$2,014,640	1,651	1,615		
14	Total C&I		$19,006,674	$8,292,413	10,893	10,527	**$1,744.83**	**$787.74**
15	**TOTAL**		**$43,343,216**	**$21,081,782**	**81,004**	**79,673**		

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

			Target Revenue per Customer		Summer 2011					Winter 2011 - 2012				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
Line			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Residential Non-heat	R-1	$121.73	$107.34	$418,346	3,904	$107.15	$0.20	$763	$467,375	3,872	$120.70	$1.03	$3,978
2	Residential Heat	R-3, R-4	$347.12	$184.96	$12,793,077	70,289	$182.01	$2.96	$207,719	$22,566,735	71,446	$315.86	$31.26	$2,233,390
3	Total Residential				$12,793,077					$22,566,735				
4														
5	Small, High Winter	G-41			$2,959,325	7,483				$6,350,235	7,844			
6	Medium, High Winter	G-42			$2,954,098	1,526				$7,430,603	1,539			
7	Large High Winter	G-43			$438,949	41				$1,057,130	38			
8	Small, Low Winter	G-51			$597,278	1,265				$782,543	1,306			
9	Medium, Low Winter	G-52			$651,079	310				$861,902	305			
10	Large Low Winter	G-53			$452,023	38				$717,814	38			
11	Large LF > 90%	G-54			$346,494	19				$415,959	19			
12	Total C&I		$1,744.83	$787.74	$8,399,247	10,682	$786.27	$1.48	$15,778	$17,616,186	11,089	$1,588.60	$156.23	$1,732,447
13	TOTAL				$21,610,669	84,876			$224,260	$40,650,296	86,407			$3,969,815
14	Seasonal RDM Adjustment								$224,260					$3,969,815

Notes

Lines 1, 2, 12 Columns(A), (B)	Attachment GHT/DECPL-5
Columns (C), (H)	Workpapers
Columns (D), (I)	Workpapers
Columns (E), (J)	Column (C) / Column (D); Column (H) / Column (I)
Columns (F), (K)	Column (B) - Column (E), Column (A) - Column (J)
Columns (G), (L)	Column (F) x Column (D), Column (I) x Column (K)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

			Target Revenue per Customer		Summer 2012					Winter 2012 - 2013				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
Line			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Residential Non-heat	R-1	$121.73	$107.34	$400,490	3,748	$106.85	$0.49	$1,846	$462,364	3,675	$125.82	($4.09)	($15,033)
2	Residential Heat	R-3, R-4	$347.12	$184.96	$12,729,928	70,842	$179.70	$5.27	$373,048	$24,512,126	71,614	$342.28	$4.83	$346,231
3	Total Residential				$12,729,928					$24,512,126				
4														
5	Small, High Winter	G-41			$3,004,719	7,602				$7,165,823	7,940			
6	Medium, High Winter	G-42			$2,947,729	1,537				$8,320,931	1,566			
7	Large High Winter	G-43			$457,215	40				$1,357,501	42			
8	Small, Low Winter	G-51			$620,045	1,295				$836,321	1,310			
9	Medium, Low Winter	G-52			$656,952	312				$935,860	313			
10	Large Low Winter	G-53			$462,561	39				$728,336	39			
11	Large LF > 90%	G-54			$316,383	14				$422,583	19			
12	Total C&I		$1,744.83	$787.74	$8,465,605	10,838	$781.12	$6.63	$71,814	$19,767,356	11,229	$1,760.44	($15.60)	($175,192)
13	TOTAL				$21,596,022	85,428			$446,707	$44,741,847	86,517			$156,005
14	Seasonal RDM Adjustment								$446,707					$156,005

Notes

Lines 1, 2, 12 Columns(A), (B)	Attachment GHT/DECPL-5
Columns (C), (H)	Workpapers
Columns (D), (I)	Workpapers
Columns (E), (J)	Column (C) / Column (D); Column (H) / Column (I)
Columns (F), (K)	Column (B) - Column (E), Column (A) - Column (J)
Columns (G), (L)	Column (F) x Column (D), Column (I) x Column (K)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2013					Winter 2013 - 2014				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Residential Non-heat	R-1	$121.73	$107.34	$394,169	3,667	$107.50	($0.16)	($592)	$493,821	3,684	$134.04	($12.31)	($45,365)
2	Residential Heat	R-3, R-4	$347.12	$184.96	$12,953,149	71,591	$180.93	$4.03	$288,368	$26,877,471	73,198	$367.19	($20.07)	($1,469,303)
3	Total Residential				$12,953,149					$26,877,471				
4														
5	Small, High Winter	G-41			$3,003,894	7,699				$7,999,789	8,037			
6	Medium, High Winter	G-42			$3,119,974	1,575				$9,179,266	1,581			
7	Large High Winter	G-43			$518,306	45				$1,473,838	45			
8	Small, Low Winter	G-51			$623,216	1,305				$873,602	1,302			
9	Medium, Low Winter	G-52			$683,908	317				$1,000,744	315			
10	Large Low Winter	G-53			$471,235	38				$771,519	39			
11	Large LF > 90%	G-54			$371,274	23				$460,166	25			
12	Total C&I		$1,744.83	$787.74	$8,791,807	11,002	$799.09	($11.34)	($124,816)	$21,758,924	11,345	$1,918.00	($173.16)	($1,964,463)
13	TOTAL				$22,139,125	86,260			$162,960	$49,130,217	88,227			-$3,479,131
14	Seasonal RDM Adjustment								$162,960					($3,479,131)

Notes

Lines 1, 2, 12 Columns(A), (B)	Attachment GHT/DECPL-5
Columns (M), (R)	Workpapers
Columns (N), (S)	Workpapers
Columns (O), (T)	Column (M) / Column (N); Column (R) / Column (S)
Columns (P), (U)	Column (B) - Column (O), Column (A) - Column (T)
Columns (Q), (V)	Column (P) x Column (N), Column (S) x Column (U)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2014					Winter 2014 - 2015				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)
1	Residential Non-heat	R-1	$121.73	$107.34	$388,594	3,614	$107.53	($0.19)	($687)	$388,238	3,159	$122.90	($1.17)	($3,697)
2	Residential Heat	R-3, R-4	$347.12	$184.96	$13,245,331	72,562	$182.54	$2.42	$175,820	$27,385,331	76,270	$359.06	($11.94)	($910,895)
3	Total Residential				$13,245,331					$27,385,331				
4														
5	Small, High Winter	G-41			$3,192,573	7,800				$8,311,916	8,486			
6	Medium, High Winter	G-42			$3,234,255	1,590				$9,498,893	1,679			
7	Large High Winter	G-43			$643,606	40				$1,598,755	50			
8	Small, Low Winter	G-51			$627,080	1,302				$896,110	1,337			
9	Medium, Low Winter	G-52			$691,224	317				$1,040,248	321			
10	Large Low Winter	G-53			$463,789	35				$884,813	41			
11	Large LF > 90%	G-54			$394,871	20				$450,250	27			
12	Total C&I		$1,744.83	$787.74	$9,247,399	11,103	$832.84	($45.10)	($500,720)	$22,680,984	11,940	$1,899.54	($154.71)	($1,847,245)
13	TOTAL				$22,881,325	87,279			-$325,587	$50,454,553	91,369			-$2,761,837
14	Seasonal RDM Adjustment								($325,587)					($2,761,837)

Notes

Lines 1, 2, 12 Columns(K), (L)	Attachment GHT/DECPL-5
Columns (W), (AB)	Workpapers
Columns (X), (AC)	Workpapers
Columns (Y), (AD)	Column (W) / Column (X); Column (AB) / Column (AC)
Columns (Z), (AE)	Column (B) - Column (Y), Column (A) - Column (AD)
Columns (AA), (AF)	Column (Z) x Column (X), Column (AC) x Column (AE)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

			Target Revenue per Customer		Summer 2015					Winter 2015 - 2016				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
Line			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)
1	Residential Non-heat	R-1	$121.73	$107.34	$329,373	3,101	$106.21	$1.13	$3,499	$368,107	3,073	$119.80	$1.93	$5,915
2	Residential Heat	R-3, R-4	$347.12	$184.96	$13,440,224	74,595	$180.18	$4.79	$356,979	$23,899,279	76,081	$314.13	$32.99	$2,509,631
3	Total Residential				$13,440,224					$23,899,279				
4														
5	Small, High Winter	G-41			$3,384,256	8,163				$7,115,946	8,445			
6	Medium, High Winter	G-42			$3,260,739	1,621				$8,015,245	1,664			
7	Large High Winter	G-43			$581,137	50				$1,415,144	50			
8	Small, Low Winter	G-51			$596,770	1,252				$776,716	1,274			
9	Medium, Low Winter	G-52			$681,154	311				$886,259	310			
10	Large Low Winter	G-53			$525,103	39				$753,469	36			
11	Large LF > 90%	G-54			$422,274	28				$463,685	27			
12	Total C&I		$1,744.83	$787.74	$9,451,432	11,463	$824.49	($36.74)	($421,197)	$19,426,465	11,805	$1,645.59	$99.25	$1,171,639
13	TOTAL				$23,221,030	89,159			-$60,720	$43,693,851	90,959			$3,687,184
14	Seasonal RDM Adjustment								($60,720)					$3,687,184

Notes

Lines 1, 2, 12 Columns(U), (V)	Attachment GHT/DECPL-5
Columns (AG), (AL)	Workpapers
Columns (AH), (AM)	Workpapers
Columns (AI), (AN)	Column (AG) / Column (AH); Column (AL) / Column (AM)
Columns (AJ), (AO)	Column (B) - Column (AI), Column (A) - Column (AN)
Columns (AK), (AP)	Column (AJ) x Column (AH), Column (AM) x Column (AO)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2016				
					Actual Summer Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(AQ)	(AR)	(AS)	(AT)	(AT)
1	Residential Non-heat	R-1	$121.73	$107.34	$319,355	3,009	$106.13	$1.21	$3,656
2	Residential Heat	R-3, R-4	$347.12	$184.96	$13,592,320	75,548	$179.92	$5.05	$381,248
3	Total Residential				$13,592,320				
4									
5	Small, High Winter	G-41			$3,379,440	8,266			
6	Medium, High Winter	G-42			$3,368,966	1,670			
7	Large High Winter	G-43			$557,697	48			
8	Small, Low Winter	G-51			$594,855	1,237			
9	Medium, Low Winter	G-52			$661,495	307			
10	Large Low Winter	G-53			$463,563	32			
11	Large LF > 90%	G-54			$401,843	28			
12	Total C&I		$1,744.83	$787.74	$9,427,859	11,588	$813.57	($25.82)	($299,262)
13	TOTAL				$23,339,534	90,146			$85,642
14	Seasonal RDM Adjustment								$85,642

Notes

Liberty Utilities (EnergyNorth Natural Gas) Corp.
RDM Timeline

	Start	End
2017 Summer RDM True Up Period	5/1/2017	10/31/2017
Prepare Filing	2/2/2018	3/1/2018
Submit Filing	3/1/2018	3/1/2018
2017 Summer RDM Adjustment effective dates	5/1/2018	10/31/2018
2017-18 Winter RDM True Up Period	11/1/2017	4/30/2018
Prepare Filing	8/1/2018	8/31/2018
Submit Filing	9/1/2018	9/1/2018
2015-16 Winter RDM Adjustment effective dates	11/1/2018	4/30/2019
2018 Summer RDM True Up Period	5/1/2018	10/31/2018
Prepare Filing	2/1/2019	3/1/2019
Submit Filing	3/1/2019	3/1/2019
2018 Summer RDM Adjustment effective dates	5/1/2019	10/31/2019
2018-19 Winter RDM True Up Period	11/1/2018	4/30/2019
Prepare Filing	8/1/2019	8/31/2019
Submit Filing	9/1/2019	9/1/2019
2018-19 Winter RDM Adjustment effective dates	11/1/2019	4/30/2020

Liberty Utilities (EnergyNorth Natural Gas) Corp.
RDM Target Revenues: Permanent Rates

Line	Class		Rate Year 1 Pro-forma Base Rate Revenues		Rate Year 1 Average Customers		Rate Year 1 Target Revenue per Customer	
			Winter	Summer	Winter	Summer	Winter	Summer
1			(A)	(B)	(C)	(D)	(E)	(F)
2	Residential Non-heat	R-1	$577,648	$519,062	3,485	3,567	**$165.77**	**$145.53**
3	Residential Heat	R-3, R-4	$33,116,584	$16,129,504	76,309	76,479	**$433.98**	**$210.90**
4	Total Residential		$33,694,233	$16,648,566	79,794	80,045		
5	Small, High Winter Use	G-41	$9,797,494	$4,118,770	8,900	8,859		
6	Medium, High Winter Use	G-42	$11,032,480	$4,010,218	1,714	1,738		
7	Large High Winter Use	G-43	$2,207,715	$469,223	51	50		
8	Total High Winter Use		$ 23,037,690	$ 8,598,211	10,665	10,646		
9	Small, Low Winter Use	G-51	$1,064,357	$785,147	1,345	1,358		
10	Medium, Low Winter Use	G-52	$1,328,109	$779,591	318	320		
11	Large Low Winter Use	G-53	$1,161,177	$479,674	33	34		
12	Large Use, LF >90%	G-54	$668,388	$442,320	27	28		
13	Total Low Winter Use		$4,222,031	$2,486,733	1,723	1,740		
14	Total C&I		$27,259,721	$11,084,944	12,388	12,386	**$2,200.52**	**$894.95**
15	**TOTAL**		**$60,953,954**	**$27,733,510**	**92,182**	**92,431**		

Liberty Utilities

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 20-105

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIRECT TESTIMONY

OF

STEVEN E. MULLEN

July 31, 2020

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TABLE OF CONTENTS

ATTACHMENTS

Attachment	Title
SEM-1	Compliance Checklist
SEM-2	Pelham Risk Sharing Analysis
SEM-3	Depreciation Reserve Analysis
SEM-4	Decoupling Impact on EE (Company)
SEM-5	Decoupling Impact on EE (FTI Consulting)
SEM-6	EE Marketing, Builder Education, and State/Local Meetings
SEM-7	Customer Feedback re: Decoupling

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Steven E. Mullen. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. By whom are you employed and in what capacity?

A. I am employed by Liberty Utilities Service Corp. ("Liberty") as Director, Rates and Regulatory Affairs. I am responsible for rates and regulatory affairs for Liberty Utilities (EnergyNorth Natural Gas) Corp. ("EnergyNorth" or "the Company") and Liberty Utilities (Granite State Electric) Corp. ("Granite State") in New Hampshire, Liberty Utilities (Peach State Natural Gas) Corp. in Georgia, and Liberty Utilities (St. Lawrence Gas) Corp. in New York.

Q. Please state your professional experience and educational background.

A. In 2014, I was hired by Liberty as the Manager, Rates and Regulatory, and was promoted to Senior Manager in August 2017 and to my current position of Director in July 2018. In addition to managing the Rates and Regulatory Affairs department, I am responsible for the development of regulatory strategy, interacting with regulators and other parties on behalf of Liberty, reviewing and preparing testimony and other aspects of regulatory filings, and internal approval of rate changes for EnergyNorth and Granite State, among other duties.

From 1996 through 2014, I was employed by the New Hampshire Public Utilities Commission ("Commission") in various roles. Through 2008, I held positions first as a

PUC Examiner, then as a Utility Analyst III and Utility Analyst IV. In those roles, I had a variety of responsibilities that included field audits of regulated utilities' books and records in the electric, telecommunications, water, sewer, and gas industries; rate of return analysis; review of a wide variety of utility filings; and presenting testimony before the Commission. In 2008, I was promoted to Assistant Director of the Electric Division. Working with the Electric Division Director, I was responsible for the day-to-day management of the Electric Division, including decisions on matters of policy. In addition, I evaluated and made recommendations concerning rate, financing, accounting, and other general industry filings. In my roles at the Commission, I represented Commission Staff in meetings with utility officials, outside attorneys, accountants, and consultants relative to the Commission's policies, procedures, Uniform System of Accounts, rate cases, financing, and other industry and regulatory matters.

From 1989 through 1996, I was employed as an accountant with Chester C. Raymond, Public Accountant, in Manchester, New Hampshire. My duties involved preparation of financial statements and tax returns, as well as participation in year-end engagements.

I graduated from Plymouth State College with a Bachelor of Science degree in Accounting in 1989. I attended the NARUC Annual Regulatory Studies Program at Michigan State University in 1997. In 1999, I attended the Eastern Utility Rate School sponsored by Florida State University. I am a Certified Public Accountant and have obtained numerous continuing education credits in accounting, auditing, tax, finance, and utility related courses.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of EnergyNorth in support of its request for an increase to distribution revenues, including its request for approval of step adjustments to recover the revenue requirement associated with non-growth related capital additions placed in service after the test year. I also address certain issues related to the implementation of decoupling and other ratemaking impacts that depress earnings and have created financial pressures on the Company and contributed to its need to seek rate relief.

My testimony also describes the Company's request for approval of a property tax recovery mechanism, consistent with RSA 72:8-d and -e, to capture the impact of annual property tax increases that are beyond the Company's control.

In addition, I provide testimony to demonstrate the Company's compliance with the matters identified by the Commission in the February 28, 2020, secretarial letter in Docket No. DG 19-161, which was a rate case filing by EnergyNorth that was ultimately withdrawn. My testimony addresses each of these items, including and in addition to matters from Docket No. DG 17-048, EnergyNorth's prior rate case; Docket No. DG 15-362, the docket wherein EnergyNorth received approval to expand its franchise area to the towns of Pelham and Windham; and Docket No. DG 17-035, the proceeding wherein Liberty was granted approval of a special contract with the New Hampshire Department of Administrative Services ("NHDAS"). I will describe how the Company has complied with the requirements from the various orders and secretarial letter issued in these dockets.

I also briefly discuss several regulatory matters involving due dates for certain rate and other filings, the examination and review of which would serve all parties well in terms of process improvements and possible workload reduction and efficiency gains.

Lastly, I describe an upcoming customer service initiative of the Company to switch its account payment services provider, which will involve migration of current payment options through Liberty's Interactive Voice Response ("IVR") system and its website.

II. REASONS FOR RATE CASE FILING

Q. What are the main factors that led to the Company's filing of this rate case?

A. The major factors leading to this rate case filing are the lag on recovery for capital investments and increases in costs such as property taxes. These factors are described in more detail later in my testimony.

In addition to these factors, there are financial impacts related to the implementation of decoupling that have negatively impacted the Company. The decoupling impacts arose from an increase in use per customer since the 2016 test year in the prior rate case, as well as the February 2017 reclassification of 1,598 commercial and industrial customers to different rate classes based on a review of their usage. Because that reclassification happened after the test year, it was not reflected in the Docket No. DG 17-048 rate case billing determinants used to establish the revenue per customer ("RPC") amounts established as part of the decoupling mechanism. Each rate class has a different RPC amount each month. The customer reclassification changed the results that would have otherwise occurred in the class specific RPC amounts determined in the rate case. In addition, as part of its decision in Docket No. DG 17-048, the Commission adopted a revenue adjustment originally proposed by Staff based on the year-end customer count of EnergyNorth, rather than the average number of customers during the test year and using average revenues by customer class. Consequently, following the implementation of decoupling, the year-end customer count adjustment significantly overstated the estimated number of new customers and thus overstated the amount of estimated annual revenue associated with those customers. The Company did not actually receive this revenue because those customers did not exist, so the Company experienced a detrimental financial impact due to the operation of the decoupling mechanism.

Q. Would you please explain this impact in more detail?

A. The revenue adjustment was performed in a simplified manner, but the results of that adjustment were found to vary significantly from the determination of revenues to be received from customers under the Company's decoupling structure that uses monthly RPC amounts that vary by class. Due to the significant variations in monthly RPC amounts, the simplified methodology in the year-end customer count adjustment overstated the amount of revenue to be received from new customers. This had the effect of decreasing the amount of necessary distribution revenue increase in the prior rate case, which, in turn, lowered the RPC amounts calculated in that case. The longer the situation exists, the more the Company's revenues will be lower than they should be. In Order No. 26,122, the Commission recognized that a reset of the test year revenues would be necessary and directed that the next test year to be used in a rate case be no later than a twelve-month period ending December 31, 2020, so that such a reset could occur.

Q. Was termination of the Cast Iron/Bare Steel Replacement Program also a factor that led to this rate case filing?

A. Yes. With the termination of the accelerated recovery mechanism that was previously available as part of the Cast Iron/Bare Steel Replacement ("CIBS") program, the Company needs to have an alternative method to obtain timely recovery of the costs involved with the replacement of leak-prone pipe on its distribution system. As described in the joint testimony of Company witnesses Brian Frost, Robert Mostone, and Heather Tebbetts, the Company is proposing an initial step adjustment for certain capital investments made during calendar year 2020, including the replacement of leak-prone pipe. This proposal is consistent with the recommendation made by Staff in Docket No. DG 19-054 with respect to termination of the CIBS program.[1] In that docket, the Commission agreed with Staff and stated:

> We encourage Liberty to seek recovery of 2019 CIBS spending through its anticipated general rate filing rather than a CIBS FY 2020 filing. Recovery of 2019 CIBS spending through a general rate filing would be administratively efficient and recovery would commence at approximately the same time as provided for under the CIBS settlement agreement if a general rate case is filed by mid-year 2020.[2]

As described later in my testimony, the Company is also proposing step adjustments to recover capital expenditures through 2022.

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1 https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-054/INITIAL%20FILING%20-%20PETITION/19-054_2019-02-14_STAFF_RECOMMENDATION.PDF

2 Order No. 26,266 at 7.

Given all of these factors described above, the Company found it necessary to file this rate case to avoid a prolonged period of continued detrimental financial impacts and to better position the Company to effectively and efficiently provide safe and reliable service to its customers going forward.

III. REQUEST FOR STEP ADJUSTMENTS

Q. What is the largest source of downward pressure on a utility's earnings between rate cases?

A. The largest negative impact on a utility's earnings between rate cases is the regulatory lag between the time capital investments are made and the time that recovery of the revenue requirement associated with those capital investments begins, particularly when those investments are considered non-revenue producing or non-growth related. The revenue requirement includes a return on and of (*i.e.*, depreciation expense) the investment as well as associated costs, such as property taxes.

Q. Please demonstrate the impact of regulatory lag on a utility's earnings.

A. This can best be demonstrated by way of example. Assume a utility places $40,000,000 of non-growth related capital investments into service in a given year with no mechanism for rate recovery related to those investments. As a rule of thumb, the revenue requirement for utility capital investments can be roughly estimated by multiplying the capital investments by 15 percent, which provides for such items as depreciation, property taxes, and the impact of deferred taxes. For that $40,000,000 of non-growth related capital investments, the associated revenue requirement would be approximately

$6,000,000. Therefore, all else being equal, those investments in a utility's plant and equipment would reduce earnings by $6,000,000. That reduction to earnings occurs each year there is no method for rate recovery, such as in the years between test years. This is the primary reason that utilities investing in their system and replacing existing infrastructure need to file frequent rate cases.

Applying this concept to EnergyNorth, and as described in the joint testimony of Messrs. Frost and Mostone and Ms. Tebbetts, EnergyNorth made significant capital investments that were placed in service during 2018 and 2019 for which there has been no cost recovery. These investments are a primary reason for the filing of this request for an increase in distribution revenues.

Q. Please describe more specifically how the current regulatory structure for EnergyNorth impacts its earnings during the time interval between rate cases.

A. Since Liberty Utilities' acquisition of EnergyNorth in mid-2012, EnergyNorth has had to file distribution rate cases approximately every three years -- in 2014, 2017, and now in 2020.[3] The 2014 and 2017 rate cases resulted in permanent rate increases based on historic test years, each accompanied by a step increase for plant placed in service during the year following the test year (*e.g.*, for Docket No. DG 17-048, the test year was 2016 and the step increase covered plant investments in 2017). This timing creates a lag in recovery for plant investments outside the test years and not covered by step increases. In addition, EnergyNorth historically was allowed annual recovery of investments made

[3] As noted, the Company also filed a rate case in 2019 that was subsequently withdrawn.

as part of its CIBS program. However, annual recovery through the CIBS program ceased as of March 31, 2020, which was the end of the most recent CIBS year, based on a decision by the Commission in Docket No. DG 19-054. As a result, investments placed in service after 2017 that were outside of the CIBS program have not been allowed for cost recovery, and this has negatively impacted the Company's earnings.

Q. You mentioned property taxes as one of the cost items included in the revenue requirement associated with new plant investments. Have property taxes increased on previously existing plant investments?

A. Yes. Property taxes are the primary funding source for municipal budgets, and for many municipalities utility property comprises a large portion of their tax base. Utility property taxes are also a significant funding source for the State of New Hampshire. As a result, even if no new capital investments are made, utilities often see their property tax bills increase.

Q. Have EnergyNorth's property taxes increased since its last rate case?

A. Yes. The Company's prior rate case in Docket No. DG 17-048 had a 2016 test year and the property tax expense in that rate case was $9.3 million. For the test year in this case, the twelve months ended December 31, 2019, the total property tax expense was $12.4 million, which is an increase of $3.1 million, or 33 percent.

Q. Was EnergyNorth granted a step adjustment for plant investments placed in service after the last rate case that provided recovery for additional property taxes?

A. Yes. As part of Docket No. DG 17-048, the Commission approved a step adjustment for plant placed in service during calendar year 2017, and the Company was also allowed annual adjustments related to CIBS plant placed in service through March 31, 2020. However, the total amount of property tax recovery provided in those rate adjustments totaled only approximately $1.15 million, leaving an additional increase of approximately $1.95 million for which there has not been any recovery to date. As compared to the amount of the Company's request in this proceeding for a temporary distribution revenue increase, property taxes alone account for a significant portion of the earnings shortfall.

Q. Based on these facts, what is the Company requesting in its multi-year rate plan proposal?

A. The Company is requesting approval of a multi-year rate plan that includes a provision for step adjustments related to plant investments through 2022, along with a separate mechanism addressing changes in property taxes. As explained above, plant investments placed in service in the years outside of test years, particularly non-growth related capital investments, have a significant impact on EnergyNorth's earnings, as do uncontrollable increases in property taxes. Absent an alternative means of cost recovery, these costs end up causing frequent distribution rate case filings, which is administratively inefficient and costly for customers. Specifically, rate cases place significant demands on Company resources, as well as those of the Commission, its Staff, the Office of the Consumer Advocate ("OCA"), and other affected parties. Each rate case requires substantial costs to be incurred by the Company, Staff, and the OCA to prepare, review, and prosecute the case, and these costs are ultimately borne by EnergyNorth's customers. Thus, the step adjustment approach, coupled with the proposed property tax mechanism, is a reasonable method to allow for more timely recovery of assets placed in service after the test year without the need for a full rate case, and would enable the Company to potentially lengthen the time between rate cases and have a reasonable opportunity to earn a reasonable rate of return. A multi-year plan that includes a provision for step adjustments related to plant investments, along with addressing changes in property taxes, would be a step in the right direction. This would allow the Company to focus on operating the business while also reducing rate case expenses being incurred on a frequent basis.

Q. Is the Company's multi-year rate plan proposal limited solely to providing for step increases?

A. No. Although step increases would be a necessary component of a multi-year plan for at least 2020 through 2022 capital investments, the Company is open to exploring other alternatives such as performance based ratemaking mechanisms, a program similar to National Grid's Gas Infrastructure, Safety, and Reliability Plan that is in place in Rhode Island, or other possible methodologies. The Company looks forward to having discussions with the Staff and the OCA to explore alternative approaches.

Q. Have there been any other developments related to property taxes that would support approval for a rate mechanism for property taxes?

A. Yes. On June 21, 2019, the Governor signed HB 700, which established a methodology for valuing utility distribution assets for property tax purposes, codified as RSA 72:8-d and -e. Part of that law established a new methodology for assessing utility property, and a five-year phase-in period to fully transition to that new methodology. The first property tax year of the phase-in period is the tax year beginning April 1, 2020.

The law also requires the Commission to establish by order a rate recovery mechanism for the property taxes paid by a public utility. Thus, the Company's proposal for a property tax recovery mechanism is supported by the recent law.

Q. To date, has the Commission initiated any actions to develop a rate recovery mechanism for property taxes?

A. To the Company's knowledge, no, it has not.

Q. Does the law require the rate recovery mechanism to be the same for all utilities?

A. No. The law states as follows:

> **72:8-e Recovery of Taxes by Electric, Gas and Water Utility Companies**. For the implementation period of the valuation of utility company assets under RSA 72:8-d, VI and terminating with the property tax year effective April 1, 2024, the public utility commission shall by order establish a rate recovery mechanism for any public utility owning property that meets the definition of utility company assets under RSA 72:8-d, I. Such rate recovery mechanism shall either:

> I. Adjust annually to recover all property taxes paid by each such utility on such utility company assets based upon the methodology set forth in of RSA 72:8-d; or
>
> II. Be established in an alternative manner acceptable to both the utility and the public utility commission.

Q. Taking into account the last sentence quoted above, does the Company have a proposed mechanism to capture the changes in property taxes that it will experience pursuant to RSA 72:8-d?

A. Yes. As the Company has assets in many communities, and understanding that the law is new and requires changes to valuation methodologies previously used by those municipalities, it is likely there will be challenges over the first couple of years of implementation that will have to be worked through as the communities and Liberty understand the full effects of the new law and make sure it is applied appropriately. As an initial data point, many municipalities did not change the property valuations on their June 2020 tax bills, even though those bills are for the first property tax year impacted by the law. Given the likelihood of inconsistent treatment and timing of the property tax adjustments among the municipalities, it is imperative that any recovery mechanism be simple to administer for all involved. With that in mind, the Company proposes a full property tax recovery mechanism that each year compares the most recent municipal and state property tax bills to the amount currently collected in distribution rates. Such a mechanism would be simple to implement, administer, and verify, and would be consistent with the letter and spirit of the cost recovery contemplated in the law.

Q. Would the Company's proposed property tax mechanism cover all property taxes paid by the Company and not just the property that is considered "utility company assets" pursuant to RSA 72:8-d?

A. Yes.

Q. Why is it reasonable to include certain assets beyond "utility company assets" in such a mechanism?

A. To begin, recall that Liberty does not profit off property taxes; they are simply a pass-through cost. In addition, "utility company assets"[4] encompass the vast majority of the Company's taxable property, so the inclusion of non-"utility company assets" is a relatively insignificant item, particularly since the valuation of those assets is not subject to the changes prescribed in RSA 72:8-d. It is possible, however, that the taxation of non-"utility company assets" may be increased as municipalities deal with changes to their operating budgets and revenues resulting from the property tax law. Thus, inclusion of the non-"utility company assets," which are included in the Company's rate base, in the property tax mechanism would be appropriate to capture any such unintended consequences as they occur.

[4] "Utility company assets" as defined in RSA 72:8-d are: "For a gas company providing gas service to retail customers: distribution pipes, fittings, meters, pressure reducing stations, buildings, contributions in aid of construction (CIAC), construction works in progress (CWIP), and land rights including use of the public rights of way, easements on private land owned by third parties, and land owned in fee by the gas company."

Q. What are some examples of assets that are not encompassed in the definition of "utility company assets" for purposes of the valuation provisions of RSA 72:8-d and -e?

A. Examples of such assets are transmission plant, production plant, and general plant such as office buildings.

Q. Would a deferral account need to be established with respect to the property tax mechanism?

A. Yes. A deferral account would be necessary to capture the increases and decreases that may occur as the property tax year progresses, and to capture the recoveries and timing differences between tax billing periods, the start of recovery, and timing of collections.

Q. Does the Company have a proposed implementation date for the property tax mechanism?

A. Ideally, the effective date would occur soon after the Company receives its second tax bills of the property tax year in 2020, taking into consideration any adjustments by municipalities dating back to the April 1, 2020, which was the effective date of this new law. Those bills are expected to be received during the fourth quarter of 2020. However, as this mechanism is being proposed as part of this rate case, the Company proposes that the adjustment for the first property tax year of April 1, 2020, through March 31, 2021, take effect coincident with the August 1, 2021, implementation date of permanent rates at the conclusion of this proceeding. The effective date for subsequent property tax years could then be moved earlier in those calendar years.

IV. FOLLOW-UP ITEMS FROM PRIOR DOCKETS

Q. Does the Company's rate case filing address all of the directives of the Commission from prior dockets?

A. Yes. In its February 28, 2020, secretarial letter in Docket No. DG 19-161, the Commission included a list of items it required the Company to address in this rate case filing. The letter summarized the following requirements from prior dockets:

1. Analysis comparing revenue requirement versus anticipated revenue from Pelham customers per Docket No. DG 15-362;
2. From Docket No. DG 17-048:
    a. An analysis of the depreciation reserve imbalance;
    b. Information necessary to permit the Commission to evaluate the impact of decoupling;
    c. An updated analysis similar to Exhibit 46 in that docket regarding the Company's investment in the iNATGAS facility;
    d. A reduction to the proposed revenue requirement by 50 percent of any revenue shortfall for the first phase of the Keene CNG/LNG conversion;
3. Adjustments to the revenue requirement for items such as the year-end customer count versus the average customer account, vacancies, and severance pay;
4. Updated indirect gas costs; [5]
5. An identification and explanation of all non-supply costs to be recovered through the Keene Cost of Gas; and

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[5] The Company notes that, contrary to testimony from Staff during the January 10, 2020, prehearing conference in Docket No. DG 19-161, each EnergyNorth rate case filed subsequent to Liberty ownership has included an updated analysis of indirect gas costs as part of Functional Cost of Service Studies that were filed in each case. However, due to the particular circumstances of each case and how they were resolved, the indirect gas costs remained static, notwithstanding the fact that the Company did provide updated analyses of the costs.

6. If applicable, supporting information for the use of a test year other than a calendar year test year (*note: this item is not applicable to the current filing because the test year for this filing is calendar year 2019*).

The Company's filing presents the information necessary to address each of these directives, along with related requirements from Docket No. DG 15-362, Docket No. DG 17-035, and Docket No. DG 17-048. This section of my testimony describes how the Company has complied with the requirements from the various orders and secretarial letter issued in these dockets.

Q. Have you included an attachment that identifies the various requirements from those dockets and where the Company is addressing them in the rate case filing?

A. Yes. Attachment SEM-1 presents a list of the various requirements along with a reference to the Company's testimonies and attachments where the pertinent information is located.

Q. Please describe the follow-up information provided in the Company's filing with respect to Docket No. DG 15-362, the Windham and Pelham franchise docket.

A. As discussed in that docket, the Company is serving customers in Pelham via a newly constructed take station on the Concord Lateral that is owned by Tennessee Gas Pipeline. Customers in Pelham are served under Managed Expansion Area rates in order to help pay the cost of the take station. In Docket No. DG 15-362, the Commission approved a settlement agreement that, in part, included a "risk sharing" mechanism whereby, as applicable to this rate case filing, the Company is required to prepare a discounted cash flow ("DCF") analysis that compares the revenue requirement of the take station with the anticipated annual revenue from new Pelham customers. If there is a shortage in the average anticipated annual revenue over a three-year period following the date of implementation of permanent rates, as compared to the average annual revenue requirement over the same three-year period, the Company is required to absorb one-half of that shortfall.

Q. When was the Pelham take station placed into service?

A. It was placed into service on January 29, 2018.

Q. What is the proposed implementation date for permanent rates?

A. The proposed implementation date for permanent rates in this case is August 1, 2021.

Q. In accordance with the settlement agreement in Docket No. DG 15-362, what is considered as "anticipated revenue?"

A. The settlement agreement in that docket defines "anticipated revenue" as follows: "For purposes of this risk sharing section, anticipated revenue will include committed revenue plus Estimated Annual Margin as defined in EnergyNorth's main extension provision in its tariff."

Q. Has the required analysis been prepared?

A. Yes. Attachment SEM-2 presents the required analysis. As shown in Attachment SEM-2, the calculated average annual shortfall is approximately $129,165, with one-half of that amount being $64,583.

Q. Will this information be updated as the case proceeds?

A. Yes. It is expected that during the course of this proceeding additional sales opportunities will materialize, thus reducing the estimated shortfall.

Q. Have the results of the analysis been incorporated into the overall revenue requirement schedules?

A. Yes. The adjustment is included on Schedule RR-EN-3-1 in the attachments to the permanent rates testimony of Company witnesses David Simek and Kenneth Sosnick.

Q. Please describe the follow-up items you are addressing from Docket No. DG 17-048, EnergyNorth's last rate case, as identified in the secretarial letter.

A. The items I discuss are as follows: (i) the status of the amortization of the depreciation reserve deficiency that was determined in that case; and (ii) various items with respect to the topic of decoupling, including information to enable the Commission to evaluate the impact of decoupling. In addition, although not noted in the secretarial letter, I also provide a description of how various software-related items were assigned to the 3-, 5-, and 10-year amortization buckets.[6]

Q. With respect to the depreciation reserve, what was required as part of the Commission's Order No. 26,122 in Docket No. DG 17-048?

A. A relatively large depreciation reserve deficiency of just over $9.9 million was determined in that docket, and the order approved its amortization over a six-year period.

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[6] Order No. 26,156 (July 10, 2018), at 7.

As part of its order, the Commission adopted the Company's position to perform a re-examination of the reserve variance in EnergyNorth's next rate case, rather than performing a full depreciation study.

Q. Has that analysis been performed?

A. Yes. The Company engaged the services of Management Applications Consulting, Inc. ("MAC"), which is the same consulting firm that prepared the depreciation study in Docket No. DG 17-048, in order to leverage the consultant's knowledge of the proceeding as well as its existing database of Company plant information. A copy of MAC's technical report is provided as Attachment SEM-3.

Q. What were the results of that analysis?

A. As detailed in Attachment SEM-3, the results of the review were that the reserve deficiency had actually grown since the last rate case to $16.4 million. The result was not what was expected as the amortization of the $9.9 million deficiency, which began in May 2018, was expected to decrease. However, as described in the consultant's report, there are several factors that contributed to this result, including the regulatory lag between the period involved in the study (i.e., plant in service as of December 31, 2016) and the May 1, 2018, start of the amortization; the fact that during that interim period a reserve surplus from an earlier case was still being amortized which, coupled with the fact that a deficiency actually existed, increased the amount of the deficiency by approximately $3.4 million; and the Company's long-standing cost of removal estimate of 10 percent that is applied to certain capital projects that dates back to prior ownership of the Company.

Q. Did the consultant have any recommendations as to how to address the reserve deficiency going forward?

A. Yes. Although MAC recommended the Company continue to use the 10 percent proxy for the cost of removal, MAC further recommended that the Company analyze jobs of various sizes and types to ascertain whether the 10 percent proxy currently being used for cost of removal should be adjusted downward. In addition, MAC recommended that the new depreciation study including calendar year 2020 plant data be performed during 2021 to determine if the life analyses support a longer service life for any accounts.

Q. Is the Company requesting any adjustment to the depreciation reserve deficiency amortization that was approved by the Commission in Docket No. DG 17-048?

A. No. The Company has determined that the best course of action is to follow the recommendations of its consultant and perform additional analysis to determine if any internal policies need to be changed. Thus, the Company is not proposing any adjustment to the approved six-year amortization of the reserve deficiency.

Q. Next, what are the decoupling items from Docket No. DG 17-048 that you are addressing?

A. In Order No. 26,122, the Commission required EnergyNorth to file the following information in its next rate case as part of its approval of a decoupling mechanism:

1) the amount of revenue collected or passed back through this mechanism, by year;

2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs;

3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes;

4) an account of efforts taken to educate builders about energy efficiency;

5) a detailed list of meetings with state and local officials and associations to promote energy efficiency;

6) customer feedback resulting from decoupling as implemented through the rate design; and

7) any changes in the Company's credit rating.

In addition to those items, the Commission required the Company to demonstrate that decoupling has allowed the Company to "remain an effective champion of energy efficiency" and has unlocked its "ability to enthusiastically support energy efficiency policy goals."[7]

Q. Please discuss each of the above items.

A. With respect to item (1), revenue collected or passed back to customers pursuant to the decoupling mechanism can happen in one of two ways. First, through the operation of the Normal Weather Adjustment ("NWA") that appears on each customer's monthly bill during the November through April winter period, a refund or charge is determined based on the difference between actual degree days over the billing period versus the "normal" heating degree days over the same historic period. Since the implementation of

[7] Order No. 26,122 (Apr. 27, 2018), at 46.

decoupling on November 1, 2018, the total revenue passed back to customers for the NWA through the end of May 2020[8] was $2,413,206, with the totals by year shown in Table 1 below.

The second method by which revenue can be either collected or passed back to customers is through the Revenue Decoupling Adjustment Factor ("RDAF"). The RDAF was addressed in Docket No. DG 19-145, in which the Company's Cost of Gas and its Local Delivery Adjustment Charge ("LDAC") were reviewed. The RDAF is one component of the LDAC. The RDAF provides an annual reconciliation of allowed revenues versus actual revenues, and beginning November 1, 2019, customers began receiving a credit of approximately $7 million, which is being returned over a twelve-month period. The yearly amounts of revenue collected or passed back through the NWA and the RDAF are shown below in Table 1:

Table 1

Period	NWA	RDAF	Total
11/2018 - 12/2018	$ (995,662)		$ (995,662)
01/2019 - 12/2019	$ 50,691	$ (986,682)	$ (935,991)
01/2020 - 05/2020	$ 3,358,177	$ (4,008,376)	$ (650,199)
	$ 2,413,206	$ (4,995,058)	$ (2,581,852)

[8] The NWA is in effect during the November through April winter period. In the months beyond April there are still amounts reflecting April usage billed in May as well as very minor adjustments in other months related to cancel/rebill transactions that may be necessary for individual customer bills.

In summary, through May 31, 2020, customers as a whole have received a positive financial benefit since the inception of decoupling of approximately $2.6 million.

Regarding item (2), please refer to Attachments SEM-4 and SEM-5 for information prepared by the Company and FTI Consulting ("FTI"), respectively, that provide assessments of the measurable impacts of decoupling on the Company's energy efficiency programs as well as the Company's ability to remain an "effective champion of energy efficiency." FTI analyzed the Company's data as well as data of peer companies locally and in New England to gauge the impact decoupling has had on the Company's energy efficiency efforts. FTI reached several conclusions, as detailed in Attachment SEM-5, most notably that "it is clear that the increased revenue certainty that came with decoupling either incented it to more zealously expand its EE program, or eliminated disincentives to do so, and that savings from its EE programs increased as a result."[9] The positive conclusions by FTI stand out even more when one considers factors that may have otherwise tempered energy efficiency efforts during the time following the implementation of decoupling. First, the relatively modest NWA adjustments provided in Table 1 above, especially when considered on an individual customer basis, would not be expected on their own to have much of an impact on customer behavior with respect to the energy efficiency programs. Second, it is important to keep in mind that decoupling only impacts the distribution portion of customers' bills. Commodity prices have recently been lower than in the past, so when

[9] Attachment SEM-5, page 25 of 25.

customers assess their overall bill, lower Cost of Gas prices also affect customer behavior and the demand for energy efficiency measures. Finally, as described above, customers are currently receiving the benefit of a sizable credit through the RDAF. All of these factors working together, along with the infancy of the decoupling mechanism, make FTI's conclusions regarding the positive effects of decoupling on Liberty's energy efficiency efforts even more impressive.

EnergyNorth's activities and efforts through June 1, 2020, with respect to items (3), (4), and (5) above are summarized and detailed in Attachment SEM-6. Page 1 summarizes the total number of 2018, 2019, and 2020 activities through June 1, 2020, along with providing the total number of activities associated with requirements (3), (4), and (5). The remainder of Attachment SEM-6 is a detailed list of each activity including the date and details as to the type of activity, the audience, the market segment (e.g., residential, C&I), and other relevant information.

With respect to item (6), there has been very little customer feedback and few inquiries with respect to decoupling, with most of the inquiries occurring near the beginning of the implementation period. A list of the inquiries through June 1, 2020, is provided in Attachment SEM-7. The Company also refers the Commission to its report on the first 90 days of decoupling that was submitted to Staff on February 28, 2019, and was submitted to the Commission by Staff on March 4, 2019, as part of Docket No. DG 17-048.[10]

Lastly, with respect to item (7), through June 24, 2020, the Company has not experienced any changes to its credit rating as a result of the implementation of decoupling.

Q. What did the Commission require in Docket No. DG 17-048 with respect software classifications and amortization periods?

A. Because the creation of separate classifications of software with varying amortization periods in the DG 17-048 matter was new for EnergyNorth, the Commission required that in the next rate case Liberty clearly describe how each piece of software is assigned an average service life.[11]

Q. Please describe how various items of software are assigned to the 3-, 5-, and 10-year amortization buckets.

A. With each item of software, the subject matter experts who use the software and are familiar with its features are consulted as to the appropriate life to apply to the software. Those subject matter experts reside in various departments, such as Information Technology, Engineering, Dispatch and Control, or other areas, depending on the particular nature and use of the software. The amortization period for cloud-based hosting arrangements will be the term of the service contract. The amortization period

[10] The Company's 90-day report on decoupling can be accessed at: http://www.puc.nh.gov/Regulatory/Docketbk/2017/17-048/LETTERS-MEMOS-TARIFFS/17-048_2019-03-04_STAFF_FILING_LIBERTY_DECOUPLING_RPT.PDF

[11] Order No. 26,156 at 6 (July 10, 2018).

for other software solutions will depend on the specifics of the software and may vary between contracts. In some cases, details from a business case document will provide details supporting the useful life. Regardless of the particular circumstances, the Company's Plant Accounting department will not issue the job without having a clear direction on the appropriate useful life.

Q. Are there other follow-up items from Docket No. DG 17-048 identified in the secretarial letter that are addressed elsewhere in the Company's filing?

A. Yes. The following items are addressed elsewhere in the Company's rate case filing:

- An analysis of the Company's investment in the iNATGAS compressed natural gas facility is included in the joint testimony of Messrs. Clark and Stevens;
- Adjustments to the revenue requirement for a year-end customer count, employment vacancies, and severance pay are included in the joint testimony of Messrs. Simek and Sosnick;
- Information regarding production costs incurred by the Keene Division as well as any non-supply costs to be recovered through the Keene cost of gas are also included in the joint testimony of Messrs. Simek and Sosnick; and,
- Indirect gas costs are addressed in the testimony of Mr. Sosnick on the Functional Cost of Service Study.

Q. In summary, has the Company addressed all of the directives in the February 28, 2020, secretarial letter in Docket No. DG 19-161?

A. Yes, with one addition. Item 2(d) of the secretarial letter related to the Keene CNG/LNG conversion. The conversion of the Keene system from propane/air to CNG and LNG has not reached a phase where the concept of a revenue shortfall would come into effect. The only conversion that has happened to date is to the limited number of customers located at the Monadnock Marketplace and, consistent with Order No. 26,294,[12] no customer commitment requirement was required as part of the Commission's approval of the conversion of that limited portion of the system.

Q. Lastly, please describe the follow-up item from Docket No. DG 17-035 with respect to the special contract with the New Hampshire Department of Administrative Services.

A. As stated above, Docket No. DG 17-035 involved a special contract with NHDAS related to its need for temporary boilers in order to ensure uninterrupted service for various State of New Hampshire buildings during the interim period between Concord Steam's cessation of service and NHDAS's completion of necessary retrofitting of natural gas equipment at those locations. A requirement of that special contract proceeding was that Liberty inform the Commission about the final costs associated with the contract. The Company has provided this information in the joint testimony of Company witnesses William Clark and Mark Stevens.

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[12] Docket No. DG 17-068, Order No. 26,294 (September 25, 2019) at 14.

Attachment SEM-1 provides a further summary of the Company's compliance with the Commission's directives.

V. <u>DUE DATES FOR RATE AND OTHER FILINGS</u>

Q. Please provide your general comments regarding due dates of rate-related and other required filings.

A. Over just the past five years, the regulatory reporting requirements of EnergyNorth and Keene have grown to where, on a combined basis, the weekly, monthly, quarterly, and annual required filings total slightly over 400 per year. That does not include other event-driven filings such as incident reports, interruptions of service, and similar filings that each year add to that total, depending on the occurrence of the relevant "events." Those reporting requirements have been established by rules, laws, Commission orders, settlement agreements, and other measures over the years, which have for the most part included due dates either in mid-month or on the last day or first day of a month. In addition to the increase in the total number of reporting requirements, an increase in the number of reports due simultaneously has also occurred. Moreover, directives from the Commission, whether by order or secretarial letter, to file supplemental information in dockets, special reports, or other documents also typically include mid-month or end of month due dates. Although the use of overlapping due dates is most likely coincidental, it creates a significant burden on the utility.

Particularly with respect to rate-related filings, the overlapping due dates also create burdens for the Commission, its Staff, and the OCA to review and analyze those filings simultaneously, recognizing that Liberty is not the only utility submitting filings at any particular time. It is important to note that many of the same Liberty personnel who are involved with filings for EnergyNorth are also involved with filings for Granite State that fall on the same due dates or otherwise overlap.

Q. Taking your above comments into account, what do you recommend?

A. Recognizing the burden that overlapping filings can cause for those on both ends of the regulatory structure, and while recognizing that some of the overlapping dates stem from laws or Commission rules, the Company recommends that a discussion take place among Liberty, Commission Staff, and the OCA to review existing reporting requirements and deadlines and determine if certain requirements (including due dates) can be revised in terms of content or frequency, and whether some may be combined or eliminated. Through such a meeting the Company is hopeful of developing reporting requirements and timelines that work well for all involved and spread the workload to allow everyone to work more efficiently, which is in everyone's best interest.

Q. Did you raise this same issue in Granite State's recently concluded rate case, Docket No. DG 19-064?

A. Yes. In that case a provision was included in the Settlement Agreement by which the Company, Staff, and the OCA would meet by a certain date to review Granite State's reporting requirements. Liberty would seek a similar agreement in this proceeding with respect to EnergyNorth's reporting requirements.

VI. CUSTOMER SERVICE INITIATIVE

Q. Please describe the planned initiative to switch the Company's payment services provider.

A. Liberty plans to change its payment services provider from Fiserv to Kubra in January 2021. As part of that change, payment options that are currently available through the Company's IVR system and website will be processed by Kubra rather than Fiserv. Associated with change of providers, the current credit card fee payment structure will be modified.

Q. Please explain the options the Company is evaluating to change the credit card fee payment structure?

A. In response to feedback from customer satisfaction surveys, the Company is exploring two different credit card fee structures. One option is to continue the current practice of requiring the customer pay a separate transaction fee for using a credit or debit card to make their bill payment. The other option is to offer the credit card payment option without a transaction fee, with the cost of the service borne by the Company and included as part of operating costs. Customers frequently express dissatisfaction with the current structure that requires a transaction fee for credit card usage, so exploring a fee free model is important to addressing customer concerns.

Q. How would this work?

A. Under the fee free model, EnergyNorth customers would be able to pay their bills by using a credit or debit card without incurring a separate transaction fee for using that payment method. This approach is consistent with customer expectations, which are changing in response to the growing availability of digital technology and a proliferation of methods to purchase and sell goods and services in an e-commerce environment. The Company's customer satisfaction surveys show that customers expect to be able to use their credit cards without incurring a separate fee, in large part because they now routinely make purchases and pay bills using these methods. In today's economy, customers rarely pay a separate transaction fee to use a credit or debit card to make payments. Consequently, requiring a transaction fee for utility payments causes a high level of dissatisfaction for customers. A fee free payment option would be a significant step in increasing customer satisfaction.

Q. Does the Company have a specific proposal at this time?

A. No. The Company believes it would be appropriate to have discussions with Staff and the OCA to examine the pros and cons of the various alternative and keep the costs of either approach reasonable for customers. If the Company were to pursue a fee free model, it is likely that customer usage of the credit card payment option would increase substantially, and has the potential to become a relatively significant cost. For this reason, the Company will not implement the program without Commission approval.

Q. Does this conclude your testimony?

A. Yes, it does.

Liberty ENNG Rate Case – Compliance Items

Docket	Compliance Requirement	Docket No. DG 20-105 Initial Filing Cross Reference
DG 19-161 2019 Rate Case	Secretarial Letter (2/28/2020) Item 1: "In Order No. 25,987 (concerning expansion of gas service in to Pelham and Windham) the Commission approved a risk sharing mechanism requiring Liberty to absorb one half of a Pelham revenue shortfall in its first rate case after commencing service, based on a comparison of the anticipated average annual revenue requirement and an updated actual average annual revenue requirement." • "Liberty must include in its initial filing of its next rate case all the information required to be filed by Order No. 25,987, including but not limited to, a revenue requirement calculation that includes an adjustment, if applicable, as outlined in the Settlement Agreement approved in that Order, and detailed supporting schedules as required by that Settlement Agreement."	• Mullen Testimony, Att. SEM-2 • Rev. Req. Schedule EN-RR-3-1
	Secretarial Letter (2/28/2020) Item 2: Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • an analysis of Liberty's depreciation reserve imbalance (Order No. 26, 122 at 18).	• Mullen Testimony, Att. SEM-3
	Secretarial Letter (2/28/2020) Item 2: Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • the information necessary to permit the Commission to evaluate the impact of decoupling (Order No. 26,122 at 46).	• Mullen Testimony • Atts. SEM-4, SEM-5, SEM-6, SEM-7
	Secretarial Letter (2/28/2020) Item 2: Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • an analysis of Liberty's investment in its iNATGAS facility similar to Exhibit 46 in DG 17-048, in sufficient detail, to allow the Commission to evaluate the investment and its impacts on firm customers.	• Clark/Stevens Testimony
	Secretarial Letter (2/28/2020) Item 2: "Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • a reduction to Liberty's proposed revenue requirement by 50 percent of any revenue shortfall for the first phase of the Keene CNG/LNG conversion.	• Mullen Testimony (project has not progressed to that point)

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Docket	Compliance Requirement	Docket No. DG 20-105 Initial Filing Cross Reference
	Secretarial Letter (2/28/2020) Item 3: Order No 26, 122 also established a number of adjustments to be included in Liberty's revenue requirement calculations. In its next rate case filing, Liberty's revenue requirement calculation must include adjustments for each item specifically adopted in Order 26,122 (or an explanation as to the change in circumstance that obviates the need for specific adjustments). Those adjustments include: • Year-End Customer Count vs. Average Customer Count (Order No. 26, 122 at 1 O); • A payroll calculation that reflects a representative level of vacancies (Order No, 26, 122 at 11); and • Severance Pay (Order No. 26, 122 at 13).	• Simek/Sosnick Testimony (Perm)
	Secretarial Letter (2/28/2020) at 2: • "Liberty's next rate petition should also include in its initial filing updated indirect gas costs with supporting testimony and schedules." • "In addition, the initial filing should identify and explain all non-supply costs to be recovered through the Keene cost of gas."	• Sosnick Testimony (Functional Cost of Service Study) • Simek/Sosnick Testimony (Perm)
	Secretarial Letter (2/28/2020) at 2: "Finally, at the prehearing conference, Staff and the Office of the Consumer Advocate stated that a calendar year test year is preferable to a split-year test-year because it aligns with the Company's Annual Report to the PUC, Form F-16. The Commission found those statements persuasive and thus recommends Liberty use a calendar year in its next filed rate case. If it chooses not to do so, the Company must provide all supporting information in the format of a Form F-16 Annual Report."	• Not applicable: No split-year test year.

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Docket	Compliance Requirement	Initial Filing Cross Reference
DG 17-048 2017 Rate Case	Order No. 26,122 (Apr. 27, 2018): • Depreciation – Amortization of Reserve Deficiency: "Thus, we approve a six-year amortization period of the existing test year-end balance and direct the Company to prepare and present in its next rate case, a review of the reserve imbalance, a thorough explanation of the cause of any imbalance, and a proposal for amortizing that reserve imbalance." Id. at 18.	• Mullen Testimony • Att. SEM-3
	Order No. 26, 122 (Apr. 27, 2018): • Revenue Requirement Adjustments: o Customer count. Id. at 10 o Employee vacancies. Id. at 11 o Severance pay. Id. at 13.	• Simek/Sosnick Testimony (Perm)
	Order No. 26,122 (Apr. 27, 2018): • Rate Base – iNATGAS: "Nevertheless, the plant has been built and, for purposes of the base rates set in this case, we will allow recovery of the plant up to the level of costs presented in DG 14-091 ($2,245,000) plus related O&M expense. We will re-evaluate this investment in Liberty's next rate case and may consider putting more of the investment in rate base at that time. The remedy fashioned here will put ratepayers in the position they were in when this project was approved." Id. at 31-32.	• Clark/Stevens Testimony
	Order No. 26,122 (Apr. 27, 2018): • Keene: Commission permits the consolidation of Keene Division distribution rates with those of EnergyNorth subject to conditions, including: o "Liberty must reduce its revenue requirement by 50 percent of any revenue shortfall in the first distribution rate case filed within five years following construction of each Phase and by 100 percent of any revenue shortfall in the second distribution rate case filed within the five years following the construction of each Phase." Id. at 39. o Revenue requirement to include both production and distribution costs. Id. o Direct cost of Keene system shall be recovered in rates to all distribution customers. Id. o Customer commitment requirements. Id. o Liberty to file updated DCF analyses at the in-service date of each phase and annually. Id. at 40.	• Simek/Sosnick Testimony (Perm) • Sosnick Testimony (Functional Cost of Service Study) (Not all items are applicable at this time)

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Docket	Compliance Requirement	Initial Filing Cross Reference
	Order No. 26,122 (Apr. 27, 2018): • Decoupling: "Further, to assist the Commission in evaluating Liberty's decoupling, we require the Company to report in its next rate case on the following: (1) the amount of revenue collected or passed back through this mechanism, by year; (2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs; (3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes; (4) an account of efforts taken to educate builders about energy efficiency; (5) a detailed list of meetings with state and local officials and associations to promote energy efficiency; (6) customer feedback resulting from decoupling as implemented through the rate design; and (7) any changes in the Company's credit rating. The above list is not intended to be exhaustive. In short, we require the Company to demonstrate that decoupling has allowed the Company to "remain an effective champion of energy efficiency" and has unlocked its "ability to enthusiastically support energy efficiency policy goals.'" Id. at 46.	• Mullen Testimony • Atts. SEM-4, SEM-5, SEM-6, SEM-7
	Order No. 26,122 (Apr. 27, 2018): • Test Year: Liberty shall file its next distribution rate case using a test year ending no later than December 31, 2020, and that rate case shall include a report on the effects of decoupling as detailed in the order. Id. at 56.	• Mullen Testimony
	Order No. 26,156 (July 10, 2018): • As suggested by Staff, we require that Liberty, in its next rate case, clearly explain how each piece of software is assigned an A[verage]S[ervice]L[ife]. Id. at 7	• Mullen Testimony

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Docket	Compliance Requirement	Initial Filing Cross Reference
DG 17-068 Keene Declaratory Ruling re CNG/LNG	Order No. 26,274 (July 26, 2019) (order on affirming/clarifying declaratory ruling): • "We note that Puc 503.04(a) requires gas utilities to 'provide certain services to its customers when service conditions such as change in pressure or composition of gas affect or would affect efficiency of operation or adjustment of appliances.' Puc 503.04(b) further requires that if any such change occurs, the 'utility shall, without undue delay and without charge, inspect the appliances of its customers and, if necessary, readjust those appliances for the new conditions.' Based on the Staff Assessment, it appears that these provisions will apply to the Keene system conversion, and we direct Liberty to address these rules when it seeks to recover Keene conversion costs from ratepayers." Id. at 11. • "In addition, in accordance with the directives set forth in Order No. 26,122, Liberty must provide updated discounted cash flows (DCFs) based on detailed engineering plans and customer commitments that will produce at least 50% of the revenue requirement associated with the new facilities prior to the initiation of construction of each conversion phase." Id. at 13.	• Not applicable at this time.
	Order No. 26,294 (Sept. 25, 2019) (order on rehearing): • "We clarify that before initiation of construction for each phase of the Keene system conversion/expansion, Order No. 26,122 requires Liberty to file a detailed report of its business plan. The business plan shall include all conversion/expansion project costs, as well as detailed projected cost estimates for all conversion/expansion projects to be included in the revenue requirement analysis required as part of the risk-sharing mechanism. The business plan must be supported by updated DCF analyses based on detailed engineering plans and customer commitments that will produce at least 50 percent of the revenue requirement associated with the new facilities. As established in DG 17-048, such DCF analyses are the first step in gaining approval for each phase of the conversion/expansion and will be used to demonstrate that Liberty's New Hampshire ratepayers are not burdened with unfair or unwarranted costs." Id. at 14.	• Not applicable at this time

II-231

Docket	Compliance Requirement	Initial Filing Cross Reference
DG 17-035 NHDAS Special Contract	Order No. 26,018 (May 15, 2017), at 4: Liberty shall "notify the Commission if its costs related to this special contract exceed $2,725,000, and if a contract amendment is necessary and denied, an explanation of the Company's plans in light of the denial, and the expected impact on boiler operations, cost, and cost recovery."	• Clark/Stevens Testimony

Docket	Compliance Requirement	Initial Filing Cross Reference
DG 15-362 Franchise Approval in Pelham and Windham	Order No. 25,987 (Feb. 8, 2017), at 4 (Settlement Agreement Condition #4): "Liberty would recover the costs incurred to construct a take station off of the TGP Concord Lateral in Pelham through its distribution rates as part of a rate case. These costs would be amortized over 10 years, including a pre-tax return, based on the Commission-approved capital structure and cost of capital for Liberty."	• Mullen Testimony • Att. SEM-1 • Rev. Req. Schedules EN-RR-3-1
	Order No. 25,987 (Feb. 8, 2017), at 4 (Settlement Agreement Condition #5): "As a 'risk-sharing' provision Liberty would reduce its revenue deficiency in any rate case filed within five years of the in-service date of Phase 1 of the Pelham build-out as follows (as demonstrated in Appendix B of the Settlement Agreement): . . . a. In the first rate case any revenue deficiency between the anticipated average annual revenue from Pelham customers over the three years following implementation of permanent rates, and the average annual revenue requirement over the same period of the Pelham construction costs and amortization of the Pelham TGP take station, **would be reduced by one half**. If a second rate case is filed within the five year period, the amount of the reduction to the revenue deficiency **would be the full difference between** the anticipated Pelham revenue requirement and projected revenues. . . . b. For purposes of the risk-sharing provision, costs would include actual direct capital costs to date, the Pelham take station amortization expense, and projected direct capital costs for system reinforcement and customer growth to serve Pelham. . . . c. For purposes of the risk-sharing provision, anticipated revenue would include committed revenue plus Estimated Annual Margin as defined in Liberty's main extension provision in its tariff. . . . d. The risk-sharing provision would terminate if average annual revenue exceeds average annual revenue requirement. e. Liberty would file annual updated Pelham and Windham Discounted Cash Flow ("DCF") analyses in January of each year following the first full year of commencement of service until the projects achieve a positive annual return, but for no less than three years, and for no more than five years (as demonstrated in Appendix C of the Settlement Agreement). . . ."	• Mullen Testimony

Pelham DCF Analysis as of June 2020

Capital Cost w/o Take Station - Phases IA & IB & Pike	$1,612,698	Direct Costs
One time payment to TGP to build Take Station	$1,206,028.00	
Required Return (pre tax) Rate Base & Take Station	8.50%	
Take Station Annual Amortization (10 years)	($183,808)	
Net Present Value (Delta yrs 1-10 & 9.35% discount rate)	($859,770)	

Required Return (Requested Cost of Capital)

	Ratio	Rate	Pre-tax	Weighted Pre-tax
Equity	49.20%	9.30%	12.75%	6.27%
Debt	50.80%	4.38%	4.38%	2.23%
				8.50%

Year	IRS MACRS Rates	IRS MACRS Table	Book Depr	Delta Book less Tax	Tax Rate	Deferred Inc Tax	Accumulated Deferred Inc Tax	Rate Base	Required Return	$19.37 Property Tax	Insurance	O&M	Take Station Amortization of Initial Payment	Revenue Requirement	Projected Revenues MEP Rates	Delta Rev Req less Revenue		Risk Sharing Calculation
								1,612,698										
1	5	80,635	40,317	(40,317)	27.08%	(10,918)	(10,918)	1,561,463	$134,902	$31,238	$2,761	$4,470	$183,808	$397,496	$242,261	($155,235)		
2	9.5	153,206	40,317	(112,889)	27.08%	(30,570)	(41,488)	1,490,575	$129,712	$30,246	$2,761	$4,582	$183,808	$391,425	$242,261	($149,164)		
3	8.55	137,886	40,317	(97,568)	27.08%	(26,421)	(67,910)	1,423,836	$123,862	$28,872	$2,761	$4,696	$183,808	$384,318	$242,261	($142,057)		
4	7.7	124,178	40,317	(83,860)	27.08%	(22,709)	(90,619)	1,360,809	$118,347	$27,580	$2,761	$4,814	$183,808	$377,627	$242,261	($135,366)		($135,366)
5	6.93	111,760	40,317	(71,443)	27.08%	(19,347)	(109,966)	1,301,145	$113,133	$26,359	$2,761	$4,934	$183,808	$371,312	$242,261	($129,051)		($129,051)
6	6.23	100,471	40,317	(60,154)	27.08%	(16,290)	(126,255)	1,244,538	$108,192	$25,203	$2,761	$5,057	$183,808	$365,339	$242,261	($123,078)		($123,078)
7	5.9	95,149	40,317	(54,832)	27.08%	(14,848)	(141,104)	1,189,372	$103,441	$24,107	$2,761	$5,184	$183,808	$359,618	$242,261	($117,357)	Total	($387,495)
8	5.9	95,149	40,317	(54,832)	27.08%	(14,848)	(155,952)	1,134,206	$98,752	$23,038	$2,761	$5,313	$183,808	$353,990	$242,261	($111,729)		
9	5.91	95,310	40,317	(54,993)	27.08%	(14,892)	(170,844)	1,078,997	$94,061	$21,970	$2,761	$5,446	$183,808	$348,363	$242,261	($106,102)	Average	($129,165)
10	5.9	95,149	40,317	(54,832)	27.08%	(14,848)	(185,693)	1,023,831	$89,370	$20,900	$2,761	$5,582	$183,808	$342,739	$242,261	($100,478)		
																	@ 50%	($64,583)

II-234

MANAGEMENT APPLICATIONS CONSULTING, INC.

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MEMO

DATE: July 20, 2020
TO: Steve Mullen, Liberty Utilities
FROM: Paul Normand and Marcy Stefan
SUBJECT: Review of Reserve Variance Deficiency for Liberty Depreciable Gas Plant

At Liberty's request, MAC has reviewed the growth in the Company's plant as it relates to depreciable plant with the goal of quantifying the change in reserve imbalances since the Company's last depreciation study. In evaluating the change in plant balances as ordered in the last rate case, this creates a very complicated process of identifying any change by specific plant account. Since the 2016 period of time, many plant balances have been reclassified to comply with the New Hampshire Public Utility Commission's Staff audit, and we have derived the following detail comparisons by category with which to quantify the growth in the reserve imbalance:

<u>TABLE 1</u>

Historical Plant Balances and Net Salvage

					SCHEDULE A 2016		
ACCOUNT / DESCRIPTION	**PLANT BALANCE @12/31/2016**	**PLANT BALANCE @12/31/2019**	**DIFFERENCE (PLANT INCREASE)**	**% INCREASE IN PLANT**	**THEO. RSV WITH NET SALVAGE @12/31/2016**	**BOOK RSV @12/31/2016**	**RESERVE VARIANCE @12/31/2016**
367.00 Mains *(UNDER CURRENT 367 & 376)*	$234,672,697	316,221,089	81,548,392	34.75%	63,315,172	54,187,131	9,128,041
380.00 Services	$146,720,226	187,120,798	40,400,572	27.54%	68,883,816	66,714,617	2,169,199
<u>TOTAL DEPREC GAS PLANT</u>	477,852,305	631,074,215	153,221,910	32.06%	165,193,965	155,247,187	9,946,778

Note: Mains account was Account 367 @ 12/31/2016

	SCHEDULE A 2019 PRELIMINARY		
	THEO. RSV WITH NET SALVAGE @12/31/2019	**BOOK RSV @12/31/2019**	**RESERVE VARIANCE @12/31/2019**
367.00 Mains	3,904,396	404,274	3,500,122
376.00 Mains	72,758,459	60,928,702	11,829,757
380.00 Services	84,274,853	83,285,975	988,878
<u>TOTAL DEPREC GAS PLANT</u>	$205,106,324	188,750,655	$16,355,669

Note: Mains account split into 367 & 376 @ 12/31/2019
Note: See Attachments A (2016) and B (2019)

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TABLE 2

Historical Cost of Removal

DATE	$ COST OF REMOVAL	ACCUMULATED $ COST OF REMOVAL
@12/31/2012	573.53	573.53
@12/31/2013	1,502,866.45	1,503,439.98
@12/31/2014	1,604,008.61	3,107,448.59
@12/31/2015	1,504,536.59	4,611,985.18
@12/31/2016	1,736,434.75	6,348,419.93
@12/31/2017	2,527,346.53	8,866,047.53
@12/31/2018	2,843,715.44	11,709,762.97
@12/31/2019	3,738,897.19	15,448,660.16

Note: The Cost of Removal relates to the following work types:
1. Relay Main
2. Main Replacement
3. Relay service
4. Service Relocation
5. Service Replacement

Two key aspects of the Company's reserve variance growth are with respect to the replacement/retirement of large quantities of mains and services and the potential change in average service life (ASL) of depreciable assets. The first key element relating to ASL has to do with the potential increase to the life once new additions are factored into any life analyses. Based on experience and the Company's historical growth data, we would expect that a new study would derive longer service lives for both mains and services which would impact the resulting reserve variance. The second key element recognized annually is the cost of removal portion of the Company's plant replacement activities. It is this portion of costs that the Company has historically been estimating as a blanket 10% of investments in major plant accounts. In understanding this process, large growth in plant investments which has been occurring for many years, especially for key plant accounts related to mains and services, results in large amounts of unrecovered dollars being identified but not recovered in the short term.

Historically, we have observed that some utilities had periodically used a flat 10% estimate for cost of removal as a proxy to the more detailed and laborious efforts required to quantify these amounts which are primarily labor related. In the last ten years, the rapid increase in plant replacement/retirement requirements had, in many cases, resulted in a more detailed review of these costs (COR) which has resulted in being modified to reflect a much lower 3 to 5% range of costs to new plant investments. The cost areas typically considered are with respect to digging a trench, cutting and purging pipe, capping, resurfacing and flaggers/police. Again, the growth in

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these costs has been a direct result of a much higher frequency of retirement/replacement occurring for gas plant.

Based on our review of the available data (Tables 1 and 2), we offer the following recommendations to consider for the future plant activities of the Company's depreciable plant accounts:

1. Continue to record and document the Company's 10% COR by plant account.
2. In order to evaluate the current level of COR, a detailed effort coordinated between engineering (field) and accounting be undertaken for all major plant activity with respect to identifying/estimating activities relating solely to COR (plant and labor associated with activities). This should consider various types of projects where one can balance small and large projects to achieve an outcome to compare with the current 10% estimated level.
3. Once in place, consider maintaining this process going forwards to ensure that the new proposed levels are supportable.
4. The efforts surrounding the application of Items 1 – 3, above, should be undertaken as soon as possible such that the results will be available to influence the Company's next depreciation study.
5. Recommend that a new depreciation study be undertaken with the calendar year 2020 data included to ascertain if the life analyses support a longer average service life for any accounts. This should be prepared in early 2021 to provide you with immediate information as to the possible impact along with the technical support to possibly suspend the current allowed annual recovery of the shortfall.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORPORATION
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/16
WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

SCHEDULE A

FERC ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/16	DISP TYPE	ASL	ACCRUAL RATE W/O NET SALV.	ACCRUAL WITHOUT NET SALV.	NET SALV. %	SALV. FACTOR	ACCRUAL RATE W/ NET SALV.	ACCRUAL WITH NET SALV.	THEO. RSV. WITHOUT NET SALV.	THEO. RSV. WITH NET SALV.	BOOK RSV. @12/31/16	RESERVE VARIANCE	COR RATE %
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
303.00	CAPITALIZED SOFTWARE	14,745,889	S 4.0	6.2	16.13	2,378,512	0	1.00	16.13	2,378,512	5,708,940	5,708,940	4,975,703	733,237	0.00
	PRODUCTION PLANT														
305.00	STRUCTURES AND IMPROVEMENTS	1,975,163	R 1.0	35.0	2.86	56,490	0	1.00	2.86	56,490	818,047	818,047	1,374,447	-556,400	0.00
311.00	LP GAS EQUIPMENT	258,481	R 1.0	35.0	2.86	7,393	0	1.00	2.86	7,393	59,141	59,141	63,766	-4,625	0.00
320.00	OTHER EQUIPMENT-LNG	2,556,209	R 1.0	35.0	2.86	73,108	0	1.00	2.86	73,108	357,489	357,489	364,891	-7,402	0.00
320.10	OTHER EQUIPMENT-PRODUCTION	8,777,306	R 1.0	35.0	2.86	251,031	0	1.00	2.86	251,031	4,967,873	4,967,873	7,765,237	-2,797,364	0.00
	TOTAL DEPREC. PRODUCTION PLANT	13,567,159		35.0	2.86	388,021			2.86	388,021	6,202,550	6,202,550	9,568,341	-3,365,791	
	STORAGE PLANT														
361.00	STRUCTURES AND IMPROVEMENTS-LNG	57,345	R 1.0	35.0	2.86	1,640	0	1.00	2.86	1,640	13,371	13,371	9,179	4,192	0.00
363.50	OTHER EQUIPMENT-LNG	7,646	R 1.0	35.0	2.86	219	0	1.00	2.86	219	1,783	1,783	1,560	223	0.00
	TOTAL DEPREC. STORAGE PLANT	64,991		35.0	2.86	1,859			2.86	1,859	15,154	15,154	10,739	4,415	
	TRANSMISSION PLANT														
366.20	STRUCTURES AND IMPROVEMENTS	269,809	R 1.0	35.0	2.86	7,717	0	1.00	2.86	7,717	119,856	119,856	177,630	-57,774	0.00
366.30	STRUCTURES AND IMPROVEMENTS-OTHER	353,851	R 1.0	35.0	2.86	10,120	0	1.00	2.86	10,120	192,816	192,816	278,219	-85,403	0.00
367.00	MAINS	234,672,697	R 3.0	60.0	1.67	3,919,034	-15	1.15	1.92	4,505,716	55,056,671	63,315,172	54,187,131	9,128,041	0.25
369.00	MEASURING AND REGULATING STATION EQUIP.	4,909,208	S 4.0	35.0	2.86	140,403	0	1.00	2.86	140,403	1,782,000	1,782,000	1,889,616	-107,616	0.00
	TOTAL DEPREC. TRANSMISSION PLANT	240,205,565		59.0	1.70	4,077,274			1.94	4,663,956	57,151,343	65,409,844	56,532,596	8,877,248	
	DISTRIBUTION PLANT														
380.00	SERVICES	146,720,226	R 4.0	45.0	2.22	3,257,189	-60	1.60	3.55	5,208,568	43,052,385	68,883,816	66,714,617	2,169,199	1.33
381.00	METERS	14,628,345	R 3.0	32.0	3.13	457,867	0	1.00	3.13	457,867	6,058,054	6,058,054	7,838,363	-1,780,309	0.00
381.10	METERS-INSTRUMENT	188,398	R 3.0	32.0	3.13	5,897	0	1.00	3.13	5,897	46,943	46,943	31,378	15,565	0.00
381.20	METERS-ERTS	5,647,769	SQ	15.0	6.67	376,706	0	1.00	6.67	376,706	4,689,816	4,689,816	2,073,245	2,616,571	0.00
382.00	METER INSTALLATIONS	14,360,005	R 3.0	32.0	3.13	449,468	0	1.00	3.13	449,468	3,013,872	3,013,872	2,510,354	503,518	0.00
387.00	OTHER EQUIPMENT	908,013	S 6.0	19.0	5.26	47,761	0	1.00	5.26	47,761	410,276	410,276	339,112	71,164	0.00
	TOTAL DEPREC. DISTRIBUTION PLANT	182,452,756		39.7	2.52	4,594,889			3.59	6,546,268	57,271,346	83,102,777	79,507,069	3,595,708	
	GENERAL PLANT														
390.00	STRUCTURES AND IMPROVEMENTS	22,070,702	R 1.0	35.0	2.86	631,222	0	1.00	2.86	631,222	2,218,786	2,218,786	3,314,051	-1,095,265	0.00
391.00	OFFICE FURNITURE AND EQUIP.	285,566	S 4.0	18.0	5.56	15,877	5	0.95	5.28	15,078	44,136	41,929	26,275	15,654	0.00
391.10	OFFICE FURNITURE AND EQUIP.-COMPUTERS	1,840,911	S 4.0	10.0	10.00	184,091	0	1.00	10.00	184,091	1,179,639	1,179,639	297,543	882,096	0.00
391.20	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	679,916	S 4.0	5.0	20.00	135,983	0	1.00	20.00	135,983	349,087	349,087	81,882	267,205	0.00
393.00	STORES EQUIPMENT	99,421	SQ	30.0	3.33	3,311	0	1.00	3.33	3,311	19,569	19,569	28,007	-8,438	0.00
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	825,963	S 6.0	19.0	5.26	43,446	0	1.00	5.26	43,446	270,641	270,641	347,637	-76,996	0.00
394.10	TOOLS, SHOP & GARAGE EQUIPMENT-CNG STATION	221,199	S 6.0	19.0	5.26	11,635	0	1.00	5.26	11,635	203,415	203,415	192,912	10,503	0.00
397.00	COMMUNICATION EQUIPMENT	443,965	SQ	10.0	10.00	44,397	0	1.00	10.00	44,397	343,778	343,778	212,912	130,866	0.00
398.00	MISCELLANEOUS GENERAL EQUIPMENT	348,302	S 5.0	15.0	6.67	23,232	0	1.00	6.67	23,232	127,856	127,856	151,520	-23,664	0.00
	TOTAL DEPREC. GENERAL PLANT	26,815,945		24.5	4.08	1,093,194			4.07	1,092,394	4,756,907	4,754,700	4,652,739	101,961	
	TOTAL DEPREC. GAS PLANT	477,852,305		38.1	2.62	12,533,748			3.15	15,071,009	131,106,240	165,193,965	155,247,187	9,946,778	
	AMORTIZED PLANT														
392	TRANSPORTATION EQUIPMENT	2,566,140		5.0	20.00	513,228	0	1.00	20.00	513,228			623,499		0.00
396	POWER OPERATED EQUIPMENT	491,943		5.0	20.00	98,389	0	1.00	20.00	98,389			430,651		0.00
	TOTAL AMORTIZED PLANT	3,058,083		5.0	20.00	611,617			20.00	611,617			1,054,150		
	TOTAL DEPREC. & AMORTIZED GAS PLANT	480,910,388		36.6	2.73	13,145,364			3.26	15,682,626			156,301,337		
1211	OPI-STRUCTURES-RETAINED												133,284		
304/365	LAND & LAND RIGHTS	592,018													
389.00	GNL LAND & LAND RIGHTS	16,806													
1012	ARO	139,286													
	DIFF. IN ACCOUNT 367 & 380 BAL. VS PUC ANNUAL REPORT	8,352													
	TOTAL GAS PLANT IN SERVICE	481,666,850											156,434,621		

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORPORATION
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/2019
WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

SCHEDULE A

FERC ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/2019	DISP TYPE	ASL	ACCRUAL RATE W/O NET SALV.	ACCRUAL WITHOUT NET SALV.	NET SALV. %	SALV. FACTOR	ACCRUAL RATE W/ NET SALV.	ACCRUAL WITH NET SALV.	THEO. RSV. WITHOUT NET SALV.	THEO. RSV. WITH NET SALV.	BOOK RSV. @12/31/2019	RESERVE VARIANCE	COR RATE %
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	CAPITALIZED SOFTWARE														
303.10	CAPITALIZED SOFTWARE- 3 YEARS	899,372	S 4.0	3.0	33.33	299,761	0	1.00	33.33	299,761	566,269	566,269	522,934	43,335	0.00
303.20	CAPITALIZED SOFTWARE- 5 YEARS	13,147,962	S 4.0	5.0	20.00	2,629,592	0	1.00	20.00	2,629,592	10,900,573	10,900,573	10,760,273	140,300	0.00
303.40	CAPITALIZED SOFTWARE- 10 YEARS	3,539,569	S 4.0	10.0	10.00	353,957	0	1.00	10.00	353,957	1,900,188	1,900,188	2,318,763	-418,575	0.00
	TOTAL ACCOUNT 303	17,586,903		5.4		3,283,310				3,283,310	13,367,030	13,367,030	13,601,970	-234,940	
	PRODUCTION PLANT														
305.00	STRUCTURES AND IMPROVEMENTS	852,167	R 1.0	35.0	2.86	24,372	0	1.00	2.86	24,372	388,738	388,738	266,638	122,100	0.00
319.00	GAS MIXING EQUIPMENT	368,345	R 1.0	20.0	5.00	18,417	0	1.00	5.00	18,417	164,887	164,887	241,392	-76,505	0.00
320.00	OTHER EQUIPMENT-LNG	315,570	R 1.0	35.0	2.86	9,025	0	1.00	2.86	9,025	44,571	44,571	-57,148	101,719	0.00
320.10	OTHER EQUIPMENT	3,478,111	R 1.0	35.0	2.86	99,474	0	1.00	2.86	99,474	2,087,209	2,087,209	1,389,131	698,078	0.00
	TOTAL DEPREC. PRODUCTION PLANT	5,014,193		33.2	3.02	151,289			3.02	151,289	2,685,405	2,685,405	1,840,013	845,392	
	STORAGE PLANT														
361.00	STRUCTURES AND IMPROVEMENTS-LNG	96,980	R 1.0	35.0	2.86	2,774	0	1.00	2.86	2,774	19,586	19,586	17,233	2,353	0.00
363.50	OTHER EQUIPMENT-LNG	7,646	R 1.0	35.0	2.86	219	0	1.00	2.86	219	2,224	2,224	2,044	180	0.00
	TOTAL DEPREC. STORAGE PLANT	104,626		35.0	2.86	2,992			2.86	2,992	21,810	21,810	19,277	2,533	
	LNG GAS TERMINATING AND PROCESSING PLANT														
364.20	STRUCTURES AND IMPROVEMENTS-LNG	609,078	R 1.0	35.0	2.86	17,420	0	1.00	2.86	17,420	192,797	192,797	438,133	-245,336	0.00
364.80	OTHER EQUIPMENT	3,896,019	R 1.0	35.0	2.86	111,426	0	1.00	2.86	111,426	1,531,470	1,531,470	2,400,155	-868,685	0.00
	TOTAL DEPREC. LNG TERM. AND PROCESS. PLANT	4,505,097		35.0	2.86	128,846			2.86	128,846	1,724,267	1,724,267	2,838,288	-1,114,021	
	TRANSMISSION PLANT														
367.00	MAINS	11,740,462	R 3.0	60.0	1.67	196,066	-15	1.15	1.92	225,417	3,395,127	3,904,396	404,274	3,500,122	0.25
369.00	MEASURING AND REGULATING STATION EQUIP.	138,182	S 4.0	35.0	2.86	3,952	0	1.00	2.86	3,952	61,651	61,651	-44,894	106,545	0.00
	TOTAL DEPREC. TRANSMISSION PLANT	11,878,644		59.5	1.68	200,018			1.93	229,369	3,456,778	3,966,047	359,380	3,606,667	
	DISTRIBUTION PLANT														
375.00	STRUCTURES AND IMPROVEMENTS	1,689,296	R 1.0	35.0	2.86	48,314	0	1.00	2.86	48,314	147,159	147,159	211,302	-64,143	0.00
376.00	MAINS	316,221,089	R 3.0	60.0	1.67	5,280,892	-15	1.15	1.92	6,071,445	63,268,225	72,758,459	60,928,702	11,829,757	0.25
377.00	COMPRESSOR STATION EQUIPMENT	2,246,186	R 1.0	35.0	2.86	64,241	0	1.00	2.86	64,241	164,456	164,456	192,723	-28,267	0.00
378.00	MEAS. AND REG. STATION EQUIPMENT-GENERAL	7,435,290	S 2.0	35.0	2.86	212,649	0	1.00	2.86	212,649	3,479,948	3,479,948	4,324,404	-844,456	0.00
379.00	MEAS. AND REG. STATION EQUIPMENT-CITY GATE	5,294,746	S 3.0	35.0	2.86	151,430	0	1.00	2.86	151,430	1,214,751	1,214,751	1,320,344	-105,593	0.00
380.00	SERVICES	187,120,798	R 4.0	45.0	2.22	4,154,082	-60	1.60	3.55	6,642,788	52,671,783	84,274,853	83,285,975	988,878	1.33
381.00	METERS	14,097,967	R 3.0	32.0	3.13	441,266	0	1.00	3.13	441,266	4,815,475	4,815,475	4,530,427	285,048	0.00
381.10	METERS-INSTRUMENT	276,522	R 3.0	32.0	3.13	8,655	0	1.00	3.13	8,655	94,411	94,411	113,499	-19,088	0.00
381.20	METERS-ERTS	6,045,353	SQ	15.0	6.67	403,225	0	1.00	6.67	403,225	4,435,265	4,435,265	2,730,186	1,705,079	0.00
382.00	METER INSTALLATIONS	18,597,177	R 3.0	32.0	3.13	582,092	0	1.00	3.13	582,092	4,539,321	4,539,321	4,116,883	422,438	0.00
385.00	INDUSTRIAL MEASURING & REGULATING EQUIPMENT	53,375	S 6.0	19.0	5.26	2,808	0	1.00	5.26	2,808	9,832	9,832	5,332	4,500	0.00
387.00	OTHER EQUIPMENT	2,682,115	S 6.0	19.0	5.26	141,079	0	1.00	5.26	141,079	1,081,159	1,081,159	1,078,797	2,362	0.00
	TOTAL DEPREC. DISTRIBUTION PLANT	561,759,914		48.9	2.05	11,490,733			2.63	14,769,992	135,921,785	177,015,089	162,838,574	14,176,515	
	GENERAL PLANT														
390.00	STRUCTURES AND IMPROVEMENTS	22,648,772	R 1.0	35.0	2.86	647,755	0	1.00	2.86	647,755	3,631,027	3,631,027	5,622,010	-1,990,983	0.00
391.00	OFFICE FURNITURE AND EQUIP.	636,368	S 4.0	18.0	5.56	35,382	5	0.95	5.28	33,600	160,564	152,536	119,886	32,650	0.00
391.10	OFFICE FURNITURE AND EQUIP.-COMPUTERS	867,103	S 4.0	10.0	10.00	86,710	0	1.00	10.00	86,710	451,043	451,043	-403,214	854,257	0.00
391.20	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	899,621	S 4.0	5.0	20.00	179,924	0	1.00	20.00	179,924	637,036	637,036	440,849	196,187	0.00
393.00	STORES EQUIPMENT	138,142	SQ	30.0	3.33	4,600	0	1.00	3.33	4,600	30,157	30,157	35,198	-5,041	0.00
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	3,339,457	S 6.0	19.0	5.26	175,655	0	1.00	5.26	175,655	750,378	750,378	754,055	-3,677	0.00
397.00	COMMUNICATION EQUIPMENT	892,402	SQ	10.0	10.00	89,240	0	1.00	10.00	89,240	449,676	449,676	433,204	16,472	0.00
398.00	MISCELLANEOUS GENERAL EQUIPMENT	802,973	S 5.0	15.0	6.67	53,558	0	1.00	6.67	53,558	224,824	224,824	251,165	-26,341	0.00
	TOTAL DEPREC. GENERAL PLANT	30,224,838		23.8	4.21	1,272,826			4.21	1,271,044	6,334,705	6,326,677	7,253,153	-926,476	
	TOTAL DEPREC. GAS PLANT	631,074,215		38.2	2.62	16,530,012			3.14	19,836,841	163,511,780	205,106,324	188,750,655	16,355,670	
														7.97%	
	AMORTIZED PLANT														
392	TRANSPORTATION EQUIPMENT	8,367,661		5.0	20.00	1,673,532	0	1.00	20.00	1,673,532			3,649,940		0.00
396	POWER OPERATED EQUIPMENT	1,378,752		5.0	20.00	275,750	0	1.00	20.00	275,750			683,509		0.00
	TOTAL AMORTIZED PLANT	9,746,413		5.0	20.00	1,949,283			20.00	1,949,283			4,333,449		
	TOTAL DEPREC. & AMORTIZED GAS PLANT	640,820,628		34.7	2.88	18,479,295			3.40	21,786,124			193,084,104		
1050	PLANT HELD FOR FUTURE USE	852,305													
1210	OPI-LAND-RETAINED	13,665													
1211	OPI-STRUCTURES-RETAINED	133,284											133,284		
3020	FRANCHISES AND CONSENTS	250,950													
3040	LAND RIGHTS OWNED	97,504													
3641	LNG PROCSS LAND AND LAND RIGHTS	57,315													
3740	DISTR LAND & LAND RIGHTS	357,903													
3890	GNL LAND RIGHTS	121,489													
	TOTAL GAS PLANT IN SERVICE	642,705,043											193,217,388		

Liberty Utilities, NH
ENNG – Impacts of Decoupling on Energy Efficiency
As of 6/1/2020

Summary
Attached is a detailed inventory of specific marketing and promotion activities performed in 2018, 2019, and year-to-date in 2020 for the Company's natural gas energy efficiency programs. Activities are differentiated between advertisements, events, and training sessions performed, and further classified as relating to, (a) the promotion of stricter building energy codes in the state, (b) the education activities to builders, and/or (c) the engagement with state and local officials and associations to promote energy efficiency.

In summary, the Company more than doubled its volume of marketing and promotion activities between 2018 and 2019, performing 240 documented tactics in 2019 as compared to 99 in 2018. The Company increased its engagement with state and local officials and associations by 150%, and increased its education activities to builders by 88%. Specific tactics the Company deployed to promote stricter building energy codes in the state increased 64%, including where the Company expressed public support and lobbied for the full adoption of the 2015 IECC standards. In 2020, the Company is on pace to exceed its 2018 activity levels again and come close to matching if not exceeding certain 2019 activity levels, despite the market implementation challenges posed by COVID-19.

In terms of general promotion of the Company's energy efficiency programs, of noteworthy recognition is the Company's implementation of a broad-based, multi-channel mass-media campaign launched in April 2019. The campaign is a natural gas-focused energy efficiency advertising effort utilizing monthly Cable TV commercials and traditional and online radio spots, bus-wrappings, billboard advertisements, and social media marketing. This was a first-of-its kind energy efficiency marketing campaign from any of the NH utilities, which the Company is continuing to deploy on a monthly basis in 2020.

In terms of any measurable impacts decoupling has had on the results of the Company's sponsored energy efficiency programs, the Company increased its lifetime MMBtu savings achievements by 26% in 2019 compared to its 2018 savings achievements, while only increasing its program expenditure levels by 8% between 2019 and 2018.

Lastly, the Company completed a survey of its residential customers in April 2020 to measure the level of energy efficiency program awareness. As part of the survey findings, the Company found that nearly three in four customers (73%) are aware that the Company offers energy efficiency programs to help customers reduce their energy costs, which is significantly higher than the awareness level recently measured as part of the Company's annual customer satisfaction survey completed in the fall of 2019, where energy efficiency program awareness was found to be 64%. The Company had last measured customer awareness of its energy efficiency programs in its 2016 annual customer satisfaction survey, where program awareness was measured to be 57%.

FTI CONSULTING

JULY 31, 2020

EVALUATION OF THE EFFECTS OF REVENUE DECOUPLING ON ENERGY EFFICIENCY PROGRAM ACHIEVEMENT

Liberty Utilities

EXPERTS WITH IMPACT™

1. Introduction and Summary

The Power & Utilities practice at FTI Consulting Inc. ("FTI") has been retained by Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty" or the "Company") to evaluate linkages between rate decoupling and outcomes for utility-sponsored Energy Efficiency ("EE") programs. Specifically, FTI was asked to analyze changes in the behaviors of gas utilities that are generally similar to Liberty in terms of size and geography attributable to the implementation of rate decoupling and, to the extent that such changes were identified, attempt to measure the effects.

The context for our inquiry is the rate case with which this report is filed. In Liberty's most recent completed rate proceeding, the New Hampshire Public Utilities Commission (the "Commission") authorized it to implement New Hampshire's first revenue decoupling program, which includes a mechanism to adjust rates for differences between the revenue target contemplated in the Company's most recent base-rate case and actual sales revenues. By accounting for this difference, the revenue decoupling mechanism is designed to eliminate revenue risks that arise from increasing EE penetration, in addition to changes in weather and other variables.[1] When the Commission approved the implementation of this mechanism through the rate settlement in the Company's most recent base-rate proceeding, the Commission directed Liberty to report on the effectiveness of the mechanism in achieving the desired outcome, when the Company next requested a change in distribution rates.[2] This report supports fulfillment of that requirement and provides additional information to the Commission

[1] Order No. 26, 122 at p. 1. Docket No. DG-19-161.
[2] Ibid., p. 46.

and intervenors regarding the effectiveness of the Company's decoupling program in advancing EE achievement.

Our evaluation included two main avenues of inquiry. *First*, we sought to determine whether the Company's behavior regarding its EE programs changed after November 1, 2018. One stated objective of decoupling the Company's rates was the elimination of disincentives to participate in EE programs. If that objective was achieved, we expected to find evidence of greater advocacy for those programs. To determine whether this was the case, we reviewed data regarding the Company's outreach and marketing efforts before and after decoupling took effect and also data showing savings from EE programs in those two periods.

Second, we sought to isolate evidence indicating a relationship between decoupling and EE achievement through a comparative analysis of similar utilities. Here, our thesis was that, if revenue decoupling is positively correlated to EE achievement, we would find evidence of that relationship for utility companies that operate in different jurisdictions, under different management, and which decoupled their rates at different times. To undertake this part of our analysis we reviewed EE data for a number of gas utilities, and one electric utility, throughout New England.

Through this investigation, we found that there is significant evidence that revenue decoupling and EE achievement are linked. Data for Liberty shows that its behavior changed once the Commission approved its request to decouple its rates from its revenues and that significant savings from its EE programs was a direct result. We also found similar outcomes for utilities all over New England, for whom gains in EE program savings coincided with the decoupling of rates.

In the final analysis, we conclude that the Commission's approval of Liberty's request to decouple its rates from its revenues in 2018 has provided measurable support for the Company's subsequent gains in energy efficiency and that decoupling is likely to do so moving forward.

The remainder of this report is organized as follows. Section 2 provides a brief overview of utility decoupling, the Commission's approval of revenue decoupling for Liberty, and the Company's EE program. Section 3 describes the increases in the Company's activity levels we observed after November 2018 and the increases in savings from EE programs that Liberty subsequently achieved. In Section 4, we describe the comparative analyses we conducted of other utilities in New England who have implemented decoupling in roughly the last ten years and our conclusion that there has been a demonstrable increase in spending on EE programs, EE savings, or both, for most of those utilities that coincides with the implementation of decoupling. Lastly, in Section 5, we summarize our findings.

2. Revenue Decoupling

Revenue decoupling is a regulatory mechanism that first appeared in 1978 in the state of California to provide relief to natural gas utilities from reduced revenues due to natural gas supply constraints.[3] Since that time, many states have adopted decoupling measures for its electric and/or natural gas utilities through individual rate cases.

In recent years, decoupling has become more common as a growing number of state regulators and policymakers focus attention on reducing energy usage and greenhouse gas emissions. Traditional

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3 Department of Energy (2010, July). *Natural Gas Revenue Decoupling Regulation: Impacts on Industry.* U.S. Department of Energy. Retrieved from: https://www1.eere.energy.gov/manufacturing/states/pdfs/nat-gas-revenue-decoupling-final.pdf

ratemaking may incent utilities to seek to increase profits by increasing sales. Simultaneously, utilities may have a financial disincentive to pursue investments and programs, like EE, that tend to reduce sales and revenues.[4] As a result, tensions can arise between policy objectives and utilities' financial outcomes. By "decoupling" revenues from sales, which is often accomplished through some adjustment mechanism that allows the utility to achieve a fixed amount of revenue, expressed on either an overall or on a per-customer basis, that tension can be resolved. With revenues decoupled from sales, utilities can support EE and related programs without putting its revenues at risk.

In April 2018, the Commission authorized Liberty to implement what is known as "full" decoupling in November 2018.[5] Specifically, Liberty is allowed to recover a fixed amount of revenue per customer, regardless of how its throughput changes for any reason.[6] Alternatives to full decoupling include partial decoupling, which allows a utility to recover some but not all of the difference between authorized and actual revenues, and limited decoupling, which provides for recoveries of "lost" revenues attributable to throughput reductions that arise from specific measures; for example, a limited decoupling mechanism may allow a utility to recover the difference between authorized and actual revenues that result from changes to weather but not that arise from changes to economic conditions.[7]

Liberty, along with the other gas and electric utilities in New Hampshire, collaborates to provide its customers EE solutions under the "NH Saves" brand, through which they provide customers with

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4 Ibid.

5 Regulatory Assistance Project ("RAP") (2016, November). *Revenue Regulation and Decoupling: A Guide to Theory and Application*. Regulatory Assistance Project. Retrieved from: https://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf

6 Order No. 26, 122 at p. 43-45. Docket No. DG 17-048.

7 National Renewable Energy Laboratory (2009, December). *Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities*. Retrieved from: https://www.nrel.gov/docs/fy10osti/46606.pdf

incentives, information, and support designed to save energy, reduce costs, and promote environmental objectives.[8] Additionally, each of the New Hampshire utilities are individually required to implement the Energy Efficiency Resource Standard ("EERS"), which was established by the Commission in 2016 and creates savings goals expressed as a function of each utility's sales.[9] The EERS additionally requires the annual filing of updates to utility-specific EE plans (the "Statewide EE Plans") through which increasingly stringent EE targets will be achieved. The 2020 Plan Update, filed in September 2019, is the most recent.

Liberty's EE offerings include separate programs for Residential and Commercial & Industrial ("C&I") customers. Residential programs include performance audits, ENERGY STAR appliance rebates, programs targeted at low-income customers, and others.[10] Building and appliance programs are also offered to C&I customers. Additionally, Liberty engages in education and policy advocacy efforts, such as, for example, advocacy before regulatory agencies for more stringent building codes. Most of Liberty's programs also include customer outreach elements, which is to say that it conducts marketing and purchases advertising to make customers aware of its EE programs and the options to create savings they have available.

3. Company Results

FTI reviewed public data regarding Liberty's EE program and data that the Company compiled internally. Both indicate that after decoupling was authorized by the Commission, Liberty spent more on EE,

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8 New Hampshire Statewide Energy Efficiency Plan, 2020 Update (the "2020 Plan Update"). Filed September 13, 2019 in DE 17-136 at p. 8.

9 Order No. 25, 932. Docket No. DE 15-137.

10 *Energy Efficiency Programs* (2020). Liberty. Retrieved from: https://new-hampshire.libertyutilities.com/derry/residential/smart-energy-use/natural-gas/index.html

conducted more outreach and achieved greater savings compared to the period prior to decoupling implementation.

Enhanced Marketing Outreach

Liberty more than doubled the volume of its marketing and promotion activities in 2019, compared to 2018. On an ongoing basis, the Company places advertisements for its EE programs; conducts trainings for professionals in the construction and/or EE industries, including, for example, the Company's participation in the Building Operator Certification program or "button-up" workshops whose purpose is to educate homeowners regarding EE opportunities; and participates in events, which include meetings with government agencies, participation in industry conferences, and running open houses and roundtable discussions.[11] Each activity is tracked individually. In 2018, there were 99 separate instances of outreach by the Company designed to promote its EE programs. In 2019, there were 240, an increase of 142%. Outreach instances are shown below by category:

Table 1. Liberty EE Outreach by Category

	Advertisement	Event	Training	Total
2018	45	25	29	99
2019	72	62	106	240
YoY Change	60%	148%	266%	142%

Liberty also tracks the primary objective of each outreach activity. Primary objectives include the Company's promotion of enhanced building standards, which it seeks to achieve through advertisement and participation in industry events; engagement with state and local officials regarding EE and the

[11] Building Operator Certification (2016, January). *BOC Offered in New Hampshire!* Retrieved from: https://www.theboc.info/boc-offered-in-new-hampshire/

Company's EE program, and others.[12] Table 2 shows the change in the frequency of outreach for each type of objective between 2018 and 2019. Note that the totals exceed those reported in Table 1 since some instances of outreach had multiple objectives.

Table 2. Liberty EE Outreach by Objective

	2018	2019	Increase
Promotion of enhanced building codes	11	18	64%
Education activities with builders	16	30	88%
Engagement with state and local officials	22	55	150%
Other activities	66	161	144%

One of the most impactful approaches to outreach regarding its EE programs that the Company has taken has been a broad-based, multi-channel mass-media campaign launched in April 2019. The campaign includes television and radio commercials, online content, "bus-wrappings", billboard advertising, and social media marketing. The program, which is still ongoing, is the first of its kind in New Hampshire. Customer awareness is one of the key metrics that the Company uses to evaluate the effectiveness of its marketing efforts. Those data indicate that the measures described above have yielded benefits. In April 2020, the Company conducted a survey and determined that 73% of its customers were aware of its EE programs and their potential to help reduce energy costs. In mid-2019, awareness had been considerably lower, 64%, and in 2016, the most recent previous survey, awareness was only 57%.

[12] Much of the Company's 2019 efforts were devoted to advocating for full adoption of the 2015 International Energy Conservation Code ("2015 IECC"), which was adopted, with amendments, by the New Hampshire State Building Code Review Board in September 2019. See https://www.puc.nh.gov/EnergyCodes/energypg.htm

Savings in Recent Years

Available data indicate that the Company's EE savings following decoupling have been significant. Overall, the Company increased the savings achieved by the EE program, measured in lifetime MMBtu savings, by 26% in 2019 compared to its 2018 savings achievements, while only increasing its program costs by 8% over the same period. Savings were achieved in most of Liberty's rate classes (and in all of its largest classes).

Using weather-normalized sales data that Liberty provided, FTI calculated normal use per bill for each rate class for the twelve-month period beginning each November (referred to below as a "decoupling year"). To account for long-run trends, normal use per bill for the annual periods of November 1st through the subsequent October 31st were calculated for each of the five decoupling years that end with October 2019. Results are summarized below.

Table 3. Liberty Usage by Customer Group (average dth/bill)

Normal Usage Per Bill by Class	Nov14-Oct15	Nov15-Oct16	Nov16-Oct17	Nov17-Oct18	Nov18-Oct19
R-1	212	216	218	213	196
R-3 & R-4	752	726	738	748	747
G-41, G-42 & G-43	45,209	44,417	46,009	43,002	40,831
G-51 & G-52	16,745	16,210	17,664	17,715	17,453

To compile these data, we grouped customers by rate class with other, similar classes and calculated average consumption per bill (dth) for each aggregation. In some instances, rate classes with a very small number of customers were excluded.[13] The results indicate a decreasing consumption across classes. Large reductions were observed for the C&I high-winter-use group (rate classes G-41, G-42 &

[13] This includes, for example, the G-53 and G-54 industrial customer rate classes.

G-43) and residential non-heating group (R-1). The results for the residential heating group (R-3 & R-4) indicate smaller declines, expressed on a percentage basis, but represent a sizeable portion of the Company's customers.[14] In each instance, the red line indicates the implementation of decoupling.

Figure 1. Change in Annual Consumption, Residential Non-Heating Group

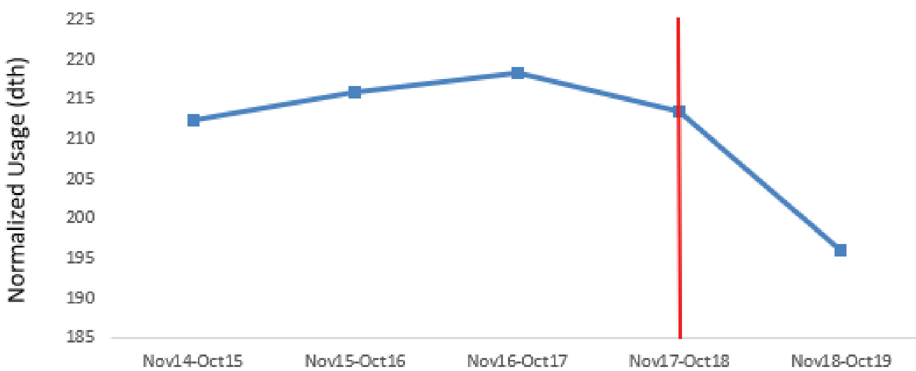
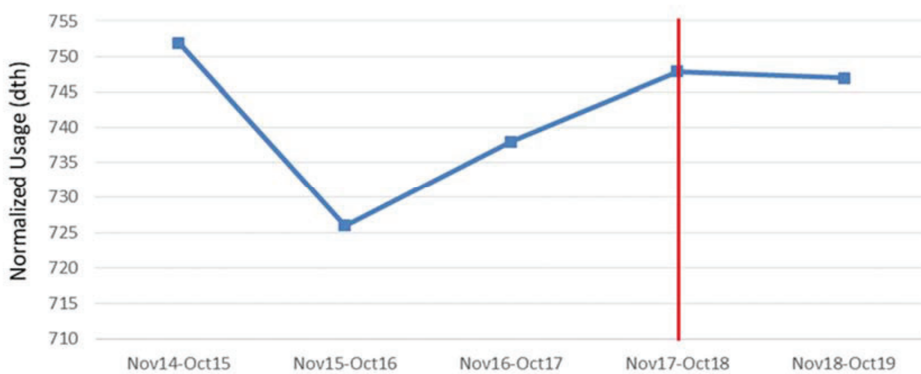


Figure 2. Change in Annual Consumption, Residential Heating Group



The low-winter-usage C&I group (G-51 & G-52) had a significant reduction in usage per bill as well. Although caution should be taken in inferring too much from such a limited sample size, the consistency

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[14] As of October 2019, the R-3 rate class (75,307 customers) and the R-4 rate class (5,667 customers) combined for a total of 80,974 customers, or 83% of Liberty's 97,348 total customers.

of these data suggest a change in customer behavior that may have coincided with the implementation of decoupling and the changes in Liberty's outreach efforts described above which, as we describe below, is consistent with our other findings. Year over year changes for each aggregation are shown below.

Figure 3. Change in Annual Consumption, C&I High-Winter-Use Group

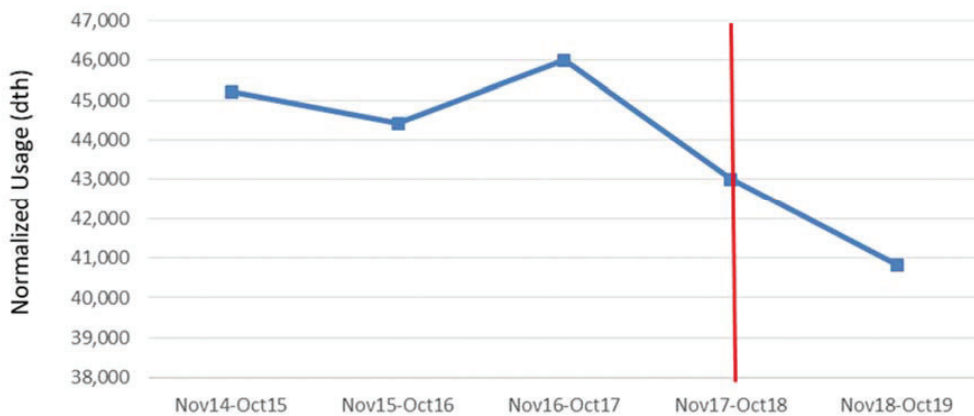
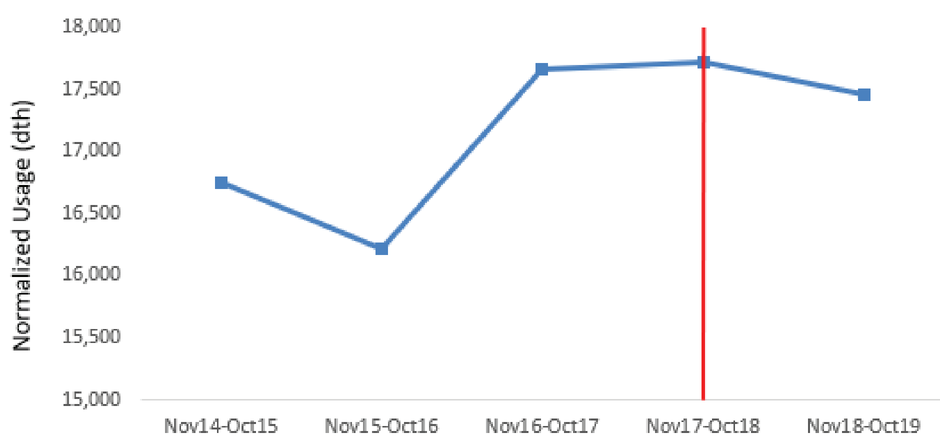
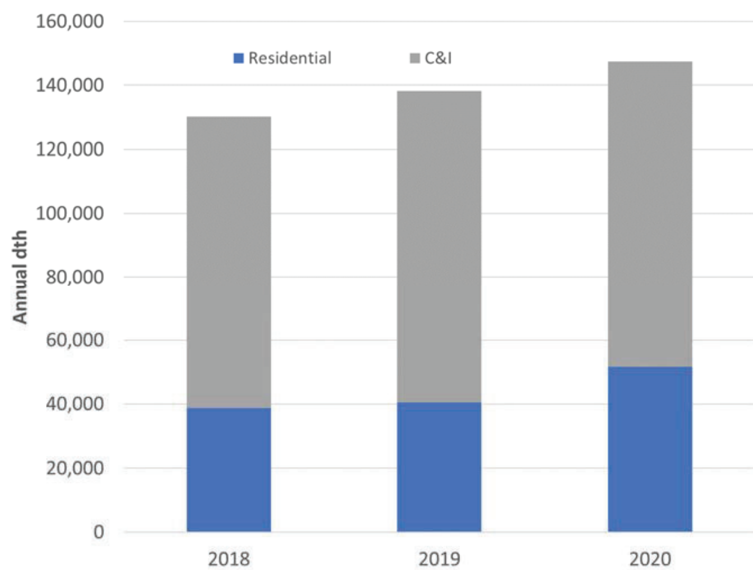


Figure 4. Change in Annual Consumption, C&I Low-Winter-Use Group



Moving forward, Liberty's EE achievement is expected to remain strong, particularly in the residential segment. FTI has reviewed data from the last Statewide EE Plans filed with the Commission in DE 17-136. Those data indicate expectations of continued strong growth in savings. Below, Liberty's EE targets for annual and lifetime savings approved each year by the Commission are reported for the three years ending in 2020.[15,16]

Figure 5. Liberty Energy Efficiency Plan, Annual Savings by Customer Class, 2018-2020



Notably, although C&I gains drove growth in savings from 2018 to 2019, benefits from the residential sector are expected to provide the basis for most of the expansion of the EE program in 2020. Planned residential savings for 2020, expressed on an annual and lifetime basis, are expected to increase by roughly 28% and 35%, respectively, compared to 2019.

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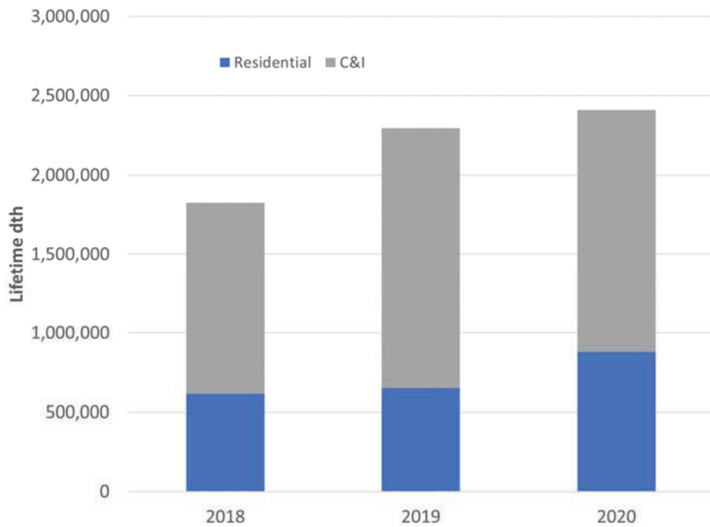
15 Order No. 26, 323. Docket No. DE 17-136.

16 No attempt has been made to adjust or evaluate the reasonableness of the approved objectives for 2020 given the COVID-19 pandemic, ensuing economic recession, or any other factor.

Figure 6. Liberty Energy Efficiency Plan, Lifetime Savings by Customer Class, 2018-2020



One driver of those gains is expansion of the Company's ENERGY STAR Homes program, a package of incentives it offers to customers seeking to achieve the ENERGY STAR qualification, which requires independent verification that the home is 15% more efficient than currently effective state requirements.[17,18] From 2019 to 2020, acceleration of the ENERGY STAR Homes program is expected to result in an increase in annual savings of roughly 10,000 dth, meaning that the measure accounts for much of the growth shown above.[19]

[17] Liberty Utilities (2020). *Building a Home: ENERGY STAR Homes.* Retrieved from: https://libertyutilities.com/residential/smart-energy-use/natural-gas/building-a-home.html

[18] The combination of the Company's participation in the ENERGY STAR program and its advocacy for increasingly stringent building codes has the potential for compounding benefits. For example, passage of the 2015 IECC means that greater savings will be required to achieve the ENERGY STAR qualification, all else equal.

[19] See Attachment I4 of the 2020 Energy Efficiency Plan.

4. Comparative Analysis

In an effort to isolate the impacts of decoupling in these results, FTI compared the effect of decoupling on EE achievement on utilities in other jurisdictions. To do so, we compiled a group of utilities that were generally similar in certain ways to Liberty (and dissimilar in other significant ways) and reviewed data they reported to their regulators to determine how the introduction of decoupling affected their ability to generate energy savings through their EE programs. Our starting point was the universe of gas utilities in New England, of which there are twenty-four, according to the Northeast Gas Association.[20]

Of these, we eliminated the municipal utilities, including Holyoke Gas & Electric, Norwich Public Utilities, and others, as well as the companies that are either considerably larger than Liberty, such as National Grid Massachusetts, or much smaller, including Fitchburg Gas and Electric Light Co. and all of the Maine Local Distribution Companies ("LDCs"). Utilities that do not have revenue decoupling, such as Vermont Gas Services, were not considered, nor were companies such as Columbia Gas of Massachusetts ("CMA") or Liberty's Massachusetts affiliate, which decoupled its rates long enough ago that data regarding EE achievement was not sufficiently available to conduct the before and after comparisons we describe below.[21] Because Maine shares a number of important similarities with New Hampshire, and due to the lack of suitable LDCs from that state to include in our proxy group, we chose to include one electric company from Maine, Central Maine Power ("CMP"), in our analysis.

20 Northeast Gas Association. *Northeast Gas Providers – Links to Individual Company Safety Pages.* Retrieved from: https://www.northeastgas.org/nat_gas_providers.php

21 In all cases here and in the remainder of this section we adopted the convention to refer to each LDC by its current name regardless of what its name was when any event of note took place. For example, CMA was Bay State Gas at the time it first implemented decoupling.

The five utilities that comprise the proxy group are shown in Table 4. For each, the most recently available customer count is reported as well as the date on which its rates were decoupled and the docket in which the state regulator of relevance first approved decoupling.

Table 4. Proxy Group Utilities

	State	Type	Customers	Decoupling Implemented	Decoupling Docket
Connecticut Natural Gas ("CNG")	CT	Gas	177,000	Jan-14	13-06-08
Southern Connecticut Gas ("SCG")	CT	Gas	197,000	Jan-18	17-05-42
Berkshire Gas ("Berkshire")	MA	Gas	40,000	Feb-19	18-40
National Grid Rhode Island ("NGrid RI")	RI	Gas	272,000	Apr-11	4206
CMP	ME	Electric	600,000	Sep-14	2013-00168

As described in the remainder of this section, for each company we found a positive correlation between decoupling and EE achievement based on the observation that each achieved more savings from their EE programs after implementing decoupling than they did before. Moreover, we find that the change in regime is fairly evident in all cases. The clear difference in achievement pre- and post-decoupling, combined with the fact that the same change in trend was apparent regardless of where or when decoupling was implemented, creates compelling evidence of a causal relationship.

Connecticut

Public Act No. 07-242 (2007) required the Public Utilities Regulatory Authority ("PURA") of Connecticut to implement decoupling for each of the state's gas and electric utilities in the next rate case following the measure's passage. PURA first approved CNG's decoupling program in 2014 while SCG's mechanism was put into place in 2018. The CNG and SCG mechanisms are generally similar. Both are full decoupling mechanisms that reconcile rates on a dollars-per-customer basis and include weather normalization. Charges or refunds are allocated on a class-by-class basis and differentials between budgets and earned revenues are reconciled through the decoupling mechanism only if the difference is greater than $1 million. Minor differences exist regarding the treatment of customers added to the system between rate cases, but otherwise most of the same provisions are used for the two companies.

EE achievement in Connecticut is generally high. In addition to revenue decoupling, statutes also provide an opportunity for both gas and electric companies to earn incentive payments if EE targets are met or exceeded.[22]

CNG and SCG, along with the electric utilities in Connecticut, serve as administrators for the statewide EE plan, one responsibility of which is to develop three-year Conservation & Load Management Plans ("C&LM Plans"), which are approved by PURA and the Department of Energy and Environmental Protection ("DEEP").[23] Once approved, plans are updated on an ongoing basis. The current C&LM Plan covers the period 2019-2021. The latest revision to that plan was filed with PURA and DEEP on March 1, 2020.[24] FTI relied on data from the 2019-21 C&LM Plan in order to evaluate decoupling impacts for CNG and SNG. Figure 7 shows annual savings realized by the CNG EE program beginning in 2012, two years before decoupling was implemented (and the earliest date for which data was readily available) through 2016. The red line in each figure delineates the time series to periods before and after decoupling.

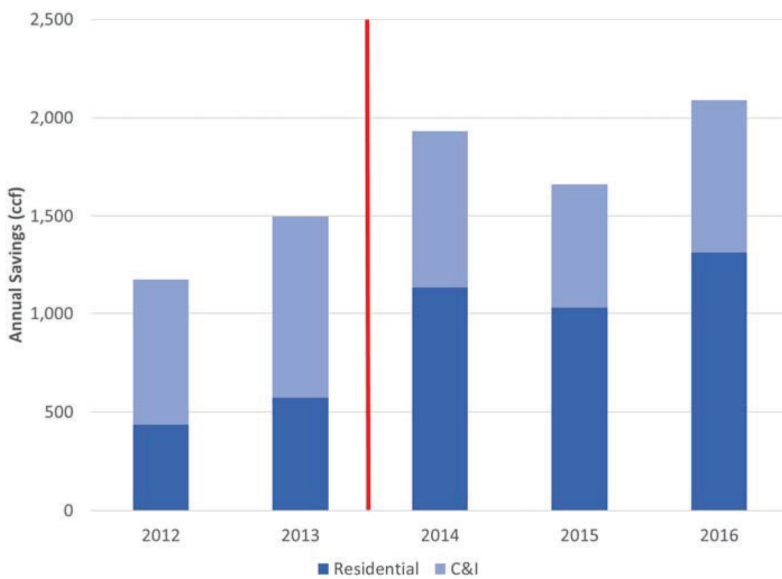
22 C2ES (2019, March). *Decoupling Policies*. Center for Climate and Energy Solutions. Retrieved from: https://www.c2es.org/document/decoupling-policies/

23 Energize Connecticut (2020). *Current and Approved C&LM Plans.* Retrieved from: https://www.energizect.com/connecticut-energy-efficiency-board/current-and-approved-clm-plans

24 Eversource Energy, United Illuminating, Connecticut Natural Gas Corporation, and Southern Connecticut Gas (2019, November). *2020 Plan Update to the 2019-2021 Conservation & Load Management*. Retrieved from: https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Final-2020-Plan-Update-Text-11-1-19.pdf?la=en

Based on annual savings, EE achievement increased substantially once decoupling was introduced. Average energy savings from EE programs for the first two years of this dataset (the pre-decoupling period) was 1,340 Ccf,[25] expressed on an annual basis. In the three years afterwards, the average annual savings increases 41% to 1,895 Ccf.

Figure 7. CNG Annual EE Savings, 2012-2016[26]



Conducting the same evaluation for SCG reveals the same pattern around the date when that utility's decoupling mechanism was approved. As shown below, for the three-year period ending in 2017, SCG's average annual EE savings was 1,551 Ccf. For the three years beginning in 2018, the year after which decoupling was implemented, annual savings increase 26% to 1,953 Ccf. Note that the 2020 goal was established in the latest C&LM Plan while data for other years report actual achievement.

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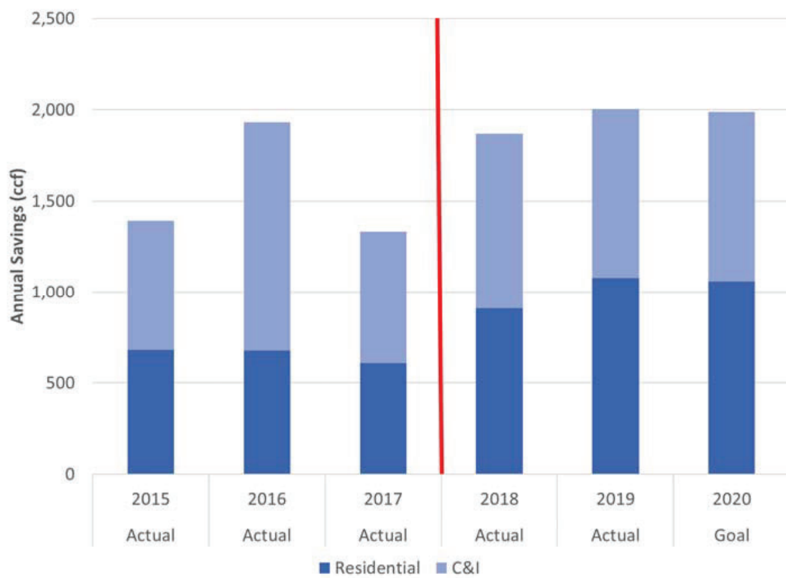
[25] Ccf is the volumetric abbreviation for 100 cubic feet of natural gas and is the equivalent of 1.037 therms.
[26] 2019-21 C&LM Plan at p. 203.

That CNG and SCG show the same result achieved at different times is impactful. Changes to variables such as weather, economic conditions, or other factors could influence consumption levels, creating a potential "false positive" attribution of the change to the implementing of decoupling. The fact that these two companies experienced the same change in trend, in the same geography but at different times suggests a meaningful correlation rather than coincidence.

Figure 8. SCG Annual EE Savings, 2015-2020[27]



Massachusetts

Berkshire's mechanism, which was first approved by the Massachusetts Department of Public Utilities ("MADPU"), provides for full decoupling on a per-customer basis. Semi-annually, by season, Berkshire reconciles its revenues per customer to a benchmark revenue amount previously established by the

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[27] 2019-21 C&LM Plan at p. 224.

MADPU and applies a Revenue Decoupling Adjustment Clause ("RDAC") to either recover or refund any variances. The RDAC is calculated and applied for each rate class.[28]

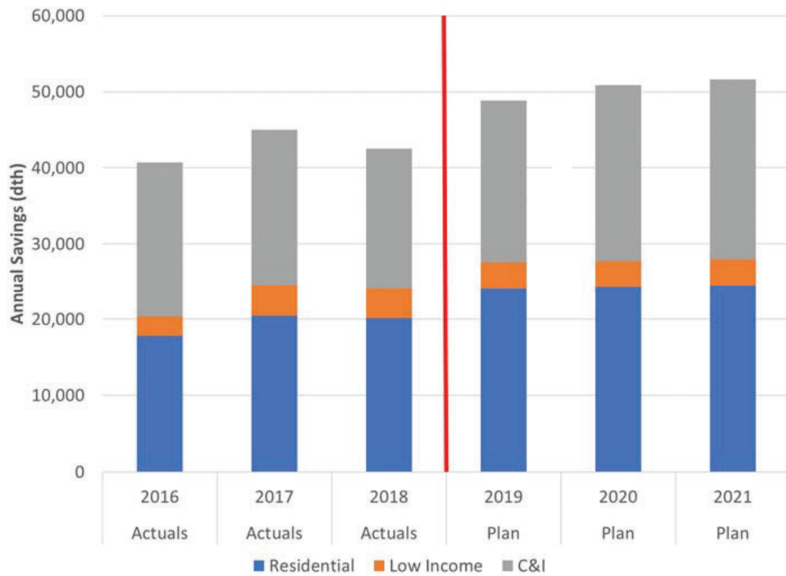
LDCs in Massachusetts are required to file EE data regarding their EE plans and program achievement regularly. Typically, they file three-year plans and separately file reports of achievement, variances between actuals and plans, and other results. Since the MADPU authorized Berkshire to implement decoupling in early 2019, FTI analyzed actual annual savings for the period 2016-2018 compared to the savings projections included in the most recent EE plan approved by the MADPU.[29]

Berkshire's EE savings show the same pattern as do those of the Connecticut utilities: a significant increase in the benefit from EE programs that coincides with the decoupling of rates and revenues. Annual savings for the three years prior to decoupling averaged 42,738 dth, as shown in Figure 10 below. The plan approved by the MADPU indicates expectation that savings will increase by about 18% to an average of 50,464 dth each year.

[28] The Berkshire Gas Company (2020, March). Tariff M.D.P.U, No. 548: *Revenue Decoupling Adjustment Clause*.

[29] Actuals for 2016-2018 were reported in Berkshire's August 1, 2016 filling in Docket No. DPU 16-121 and its current plan for 2019-2021 was filed with the DPU in Docket No. DPU 19-91 on August 1, 2019.

Figure 9. Berkshire Annual EE Savings, 2016-2021



The timing associated with these findings is important since Berkshire decoupled its rates at a different time than either of the Connecticut utilities. The fact that it experienced the same results as did those companies implies some causal correlation with the timing of the change in the rate structure.

Rhode Island

Like Connecticut, Rhode Island decoupling was enacted by statute when, in 2010, the Rhode Island legislature passed House Bill 8082, requiring the Rhode Island Public Utilities Commission ("RIPUC") to establish rates that included decoupling mechanisms in each utility's next rate case.[30] NGrid RI's mechanism was subsequently approved in Docket No. 4206 and implemented in April 2011.[31]

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30 Rhode Island State Legislature (2010, May). *Rhode Island House Bill 8082.* LegiScan. Retrieved from: https://legiscan.com/RI/text/H8082/id/468020

31 RIPUC (2012, May). *Report and Order Re: Narragansett Electric Company d/b/a National Grid's Proposed Revenue Decoupling Mechanism.* Retrieved from: http://www.ripuc.ri.gov/eventsactions/docket/4206-NGrid-RDM-Ord20745(5-25-12).pdf

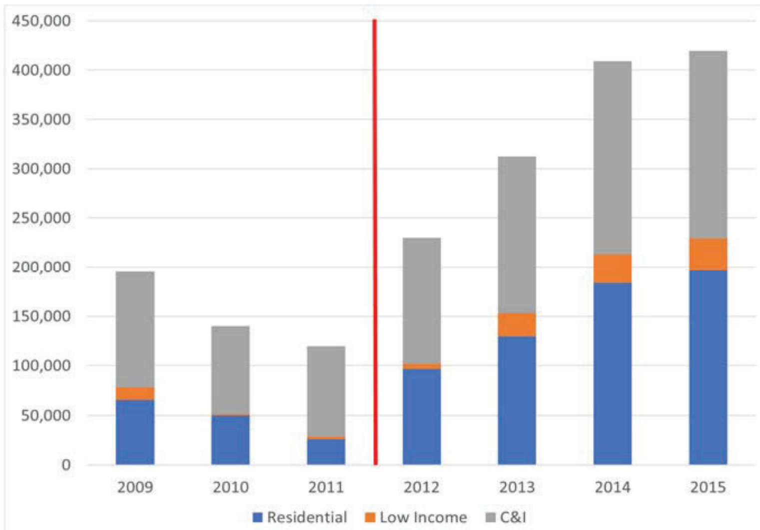
NGrid RI's mechanism provides for full decoupling based on an annual reconciliation of revenues per customer for all classes except large and extra-large C&I customers.[32] Regularly, the utility files a benchmark estimate of per-customer revenues with the RIPUC. Thereafter (assuming that the estimate is approved), variances to the benchmark are calculated and either refunded or recovered through the Revenue Decoupling Mechanism ("RDM"). Changes to the RDM have subsequently been made on an annual basis for 12-month periods from April through the following March each year.

Annually, NGrid RI files with the RIPUC a report indicating its EE achievement for the previous year. FTI reviewed the reports for each year from 2009 to 2015.[33] Among other things, those reports indicate NGrid RI's annual savings from EE programs by customer type. Annual EE savings for the period 2009-2015 are shown in Figure 10.

32 When it proposed its decoupling mechanism, NGrid RI explained that it had excluded the large and extra-large C&I classes because there were a small number of such customers and, as a result, the migration of any one customer from the class to competitive service, which is an option for certain C&I consumers in Rhode Island, could create problematic price distortions and subsidization issues. See the RIPUC's May 25, 2012 Order in Docket No. 4206, at p. 5, for additional details.

33 The reports were filed in dockets 4000 (2009), 4116 (2010), 4209 (2011), 4295 (2012), 4366 (2013), 4451 (2014), and 4527 (2015).

Figure 10. NGrid RI Annual EE Savings, 2009-2015



The data indicates that changes to EE achievement associated with decoupling is similar for NGrid RI as it is for other utilities, namely that it increases markedly at the same time that rates are decoupled from revenues. Total annual EE savings for the three years before decoupling was implemented was 151,637 MMBtu. For the three years following decoupling, the same measure increased by 109% to 317,091 MMBtu.

Maine

Decoupling was adopted in Maine in the late 1980s and early 1990s and subsequently abandoned for multiple reasons, one of the most important of which was a significant recession in the state which reduced energy consumption, causing recurring price increases.[34] Notwithstanding, the Maine Public Utilities Commission ("MEPUC") is authorized under Title 35-A to implement a decoupling mechanism,

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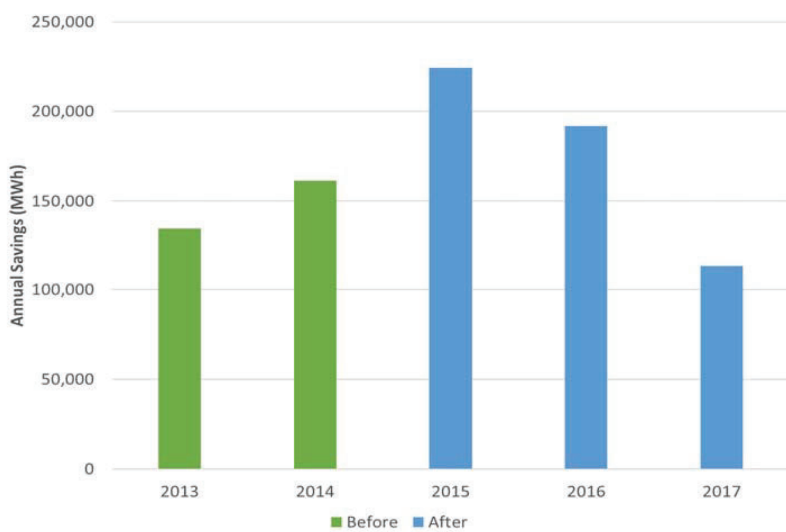
34 RAP, p. 47.

which it did in 2014, granting CMP a decoupling mechanism in Docket No. 2013-00168 which became effective in September 2014.[35]

EE programs in Maine are administered by the Efficiency Maine Trust ("Efficiency Maine"), an independent administrator that is overseen by the MEPUC. Each year, Efficiency Maine publishes reports that explain EE achievement, among other things. Most results are reported on a statewide basis. Because CMP accounts for roughly 80% of the electric load in Maine, FTI chose to compare statewide EE savings before and after CMP's decoupling mechanism took effect.[36] Those results are shown for the two years before decoupling became effective and the three years after, on an annual basis for each year, below in Figure 11. Efficiency Maine's reporting of data does not differentiate results by class.

Figure 11. Maine Annual EE Savings, 2013-2017



[35] Maine Legislature (2019, December) *Title 35-A: Public Utilities*. Retrieved from: http://legislature.maine.gov/statutes/35-A/title35-Ach0sec0.htmll
[36] MEPUC (2020, February). *2019 Annual Report at p. 19.*

Despite the inherent challenges of measuring the impact of decoupling at a single utility using statewide reporting, the same clear pattern emerges from this data as in other sets, namely that the implementation of decoupling coincides with significant increases in EE achievement. In this case, annual savings increased roughly 19% from the two years before decoupling to the three years after, from an average of 148.1 GWh saved to 176.5 GWh.

5. Conclusions

Our analysis of EE savings achieved by Liberty and by other New England utilities who have decoupled their revenues from sales supports at least five conclusions:

- *First*, the decoupling of rates in November 2018 changed the way Liberty does business with regard to its EE programs. The change in its effort to reach out to engage stakeholders and improve market penetration are significant and measurable.

- *Second*, Liberty's savings from EE programs increased significantly once decoupling was implemented.

- *Third,* the strong performance of Liberty's EE programs was expected to continue into 2020 as of the start of this year. If 2020 achievement is lower than expected, that result is most likely attributable to impacts from the COVID pandemic.

- *Fourth*, our analysis of EE achievement by other utilities around New England that have implemented decoupling provides further evidence of a causal relationship. Despite the fact that the companies FTI reviewed have different management and regulators, operate in different weather conditions, and implemented decoupling in different years, in each instance we found that a measurable increase in savings from EE programs coincided with the decoupling of rates.

Based on these findings, we conclude that there is compelling evidence of a causal link between revenue decoupling and the advancement of EE programs. Simply put, EE savings are greater when utility revenues are decoupled from sales. In Liberty's case, it is clear that the increased revenue certainty that came with decoupling either incented it to more zealously expand its EE program, or eliminated disincentives to do so, and that savings from its EE programs increased as a result. It is also reasonable to conclude that the Commission's re-authorization of the Company's decoupling mechanism will promote increased savings in the future.

Liberty Utilities, NH

EE Marketing Activities - ENNG: 2018, 2019 & YTD 2020

As of 6/1/2020

Overall Marketing/Promotion Activities

Count of Year	Column Labels			
Row Labels	Advertisement	Event	Training	Grand Total
2018	45	25	29	99
2019	72	62	106	240
2020	21	38	4	63
Grand Total	**138**	**125**	**139**	**402**

Promotion of Stricter Building Codes

Count of Year	Column Labels			
Row Labels	No	Yes	Grand Total	% Increase
2018	88	11	99	
2019	222	18	240	64%
2020	51	12	63	
Grand Total	**361**	**41**	**402**	

Education Activities to Builders

Count of Year	Column Labels			
Row Labels	No	Yes	Grand Total	% Increase
2018	83	16	99	
2019	210	30	240	88%
2020	47	16	63	
Grand Total	**340**	**62**	**402**	

Engagement with State/Local Officials & Associations

Count of Year	Column Labels			
Row Labels	No	Yes	Grand Total	% Increase
2018	77	22	99	
2019	185	55	240	150%
2020	44	19	63	
Grand Total	**306**	**96**	**402**	

Liberty Utilities, NH
EE Marketing Activities - ENNG: 2018, 2019 & YTD 202(
As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
1/18/2018	2018	Advertisement	Email Newsletter	Building Automation Systems: 7 Common Mistakes	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
1/18/2018	2018	Advertisement	Email Newsletter	Saving Energy From the Comfort of Your Couch	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
2/1/2018	2018	Advertisement	Email	Energy Audit e-blast	Home Performance with ENRGY STAR benefits/opportunities e-blast to 53,885 subscribers	Residential gas customers	Whole house weatherization and efficiency improvements	Residential	No	No	No
2/1/2018	2018	Advertisement	Bill insert sent to 71,500 natural gas customers	Home Performance with ENERGY STAR & Visual Audit Bill Insert	HPwES/Visual Audit bill insert educating customers on program benefits and enrollment	LU residential natural gas customers	Air sealing, insulation, Instant Savings Measures, visual audit, and 2% & 0% financing options	Residential	No	No	No
2/9/2018	2018	Event	Concord	Business & Industry Association Small Business Day	Business to Business energy discussions with NHSaves staff at Exhibitor table	Small business owners and managers, chambers of commerce, business associations	LU's electric and gas measures	C&I	No	No	No
2/14/2018	2018	Advertisement	Direct Mail	Energy Audit Mailer	Home Performance with ENRGY STAR benefits/opportunities mailer to 46,568 residential gas customers	Residential gas customers	Whole house weatherization and efficiency improvements, 2% financing	Residential	No	No	No
2/15/2018	2018	Advertisement	Email Newsletter	3 Options for Multiple Boiler Control	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
2/15/2018	2018	Advertisement	Email Newsletter	Quiz: How Energy Efficient Are You?	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
2/16/2018	2018	Training	Laconia	Building Operator Certification	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
2/28/2018	2018	Event	Durham	NH Association of School Business Officials-Facilities Masters Conference	School Facilities Managers' topics of interest	Northern New England school facilities managers	All EE measures	C&I	No	No	Yes
3/2/2018	2018	Training	Laconia	Building Operator Certification	Building Operator Training on all energy savings	Lakes Region Community College, facility managers	All EE measures	C&I	No	No	No
3/12/2018	2018	Event	Keene	NH Energy Week	Business to Business energy discussions with NHSaves staff at Exhibitor table	Keene government officials, community leaders, energy/business professionals	All EE measures	C&I	No	No	No
3/12/2018	2018	Event	Concord	NH Energy Week	Business to Business energy discussions at Exhibitor table	Non-profits, energy and business professionals	All EE measures	C&I	No	No	No
3/16/2018	2018	Training	Laconia	Building Operator Certification	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
3/20/2018	2018	Advertisement	Email Newsletter	5 Ways to Make Your Meetings Short (and Save Energy)	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
3/20/2018	2018	Advertisement	Email Newsletter	5 Ways to Save While Spring Cleaning	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
4/3/2018	2018	Event	Plymouth	Grafton Regional Development Corp.	small business EE workshop	Grafton small businesses	All EE measures	C&I	No	No	No
4/3/2018	2018	Training	Plymouth	Grafton Regional Development Corp.	small business EE workshop	Grafton small businesses	All EE measures	C&I	No	No	No
4/4/2018	2018	Event	Concord	Mill Brooke School Tour	NEEP Healthy Schools presentation	School administrators	All EE measures	C&I	No	No	Yes
4/10/2018	2018	Advertisement	Email	Visual Audit e-blast	Highlights and benefits of Visual Audit program sent to 53,007 subscribers	Residential gas customers	Wi-Fi T-Stats, low flow devices, pipe wrap, LEDs	Residential	No	No	No
4/10/2018	2018	Event	Concord	REPA-NH (Residential Energy Professional Associations)	EE program presentation	Energy performance professionals	All EE measures	C&I	No	No	No
4/14/2018	2018	Event	Wilton	EE at Souhegan Sustainability Fair	EE Table/Booth Setup	Home owners	Benefits of purchasing ENERGY STAR certified products and appliances and available rebates	Residential	No	No	No
4/19/2018	2018	Advertisement	Email Newsletter	Can HVAC Upgrades Improve Worker Performance?	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
4/19/2018	2018	Advertisement	Email Newsletter	Liberty is Offering FREE Energy Saving Products	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
4/19/2018	2018	Event	Concord	State Employee Manager Presentation	EE program presentation	State employees (managers)	All EE measures	C&I	No	No	Yes
4/25/2018	2018	Event	Pelham	Town of Pelham Open House	EE Table/Booth Setup	Town officials and residents	All EE measures	C&I	No	No	Yes
4/26/2018	2018	Event	Greenland	EE at Lowe's Spring Pro Event	EE Table/Booth Setup	Home owners	Benefits of purchasing ENERGY STAR certified products and appliances and available rebates	Residential	No	No	No
5/2/2018	2018	Event	Concord	NHBSR Spring Conference	Business to Business energy discussions with NHSaves staff at Exhibitor table	Businesses supporting sustainable/socially responsible operations	All EE measures	C&I	No	No	No

II-267

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
5/3/2018	2018	Training	Manchester	Energy Codes and Zero Energy Homes Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
5/3/2018	2018	Training	Manchester	Energy Codes and Zero Energy Homes Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
5/11/2018	2018	Event	Pembroke	NH State Employee Conference	EE Table/Booth Setup	State employees	All EE measures	C&I	No	No	Yes
5/12/2018	2018	Event	Nottingham	Nottingham Earth Day Festival	EE Table/Booth Setup	Home owners	Benefits of purchasing ENERGY STAR certified products and appliances and available rebates, refrigerator and freezer recycling program	Residential	No	No	No
5/16/2018	2018	Event	Concord	NHDES Pollution Prevention Training	EE Presentation for Businesses at NHDES	New Hampshire businesses in pollution prevention	All EE measures	C&I	No	No	Yes
5/17/2018	2018	Advertisement	Email Newsletter	Innovations Fuel Process Heating Efficiency	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
5/17/2018	2018	Advertisement	Email Newsletter	Infographic: Tips for Cool Summer Savings	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
5/17/2018	2018	Training	Atkinson	Energy Codes and Zero Energy Homes Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
5/24/2018	2018	Training	Center Harbor	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
6/1/2018	2018	Event	Loudon	Green Your Fleet	EV event with NHDES-4 utility tables	Businesses interested in electric cars and trucks	All EE measures	C&I	No	No	Yes
6/19/2018	2018	Advertisement	Email Newsletter	Improve Health & Comfort with Gas-Fired Dehumidification	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
6/19/2018	2018	Advertisement	Email Newsletter	5 Ways to Save While Doing Laundry	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
7/2/2018	2018	Advertisement	Online Key Word Search Ads	Pay Per Click Text Ads	Program Awareness and recognition: 7/2 through 8/20	Residents of NH	All EE measures	Residential	No	No	No
7/2/2018	2018	Advertisement	Social Media	Paid Facebook Ad (Boosted Posts)	Program Awareness and recognition: 7/2 through 8/20	Demo: Adults 25+, NH homeowners	All EE measures	Residential	No	No	No
7/2/2018	2018	Advertisement	Social Media	Programmatic Native	Targeting Tactics: Combination of targeting those searching for relevant content related to saving on energy, cutting costs, etc. as well as retargeting those who visit the website: 7/2 through 8/20	Demo: Homeowners 25+ Geo: New Hampshire	Energy efficiency tips	Residential	No	No	No
7/13/2018	2018	Advertisement	Direct Mail	Keene Energy Audit Mailer	Home Performance with ENERGY STAR informational letter sent to 710 residential customers	New Residential Keene customers	Whole house weatherization and efficiency improvements, 2% financing	Residential	No	No	No
7/18/2018	2018	Advertisement	Email	Gas Home Performance Summer Promotion e-blast	Home Performance with ENERGY STAR promo for 75% rebate or 0% financing sent to ~ 57,000 subscribers	Residential gas customers	Whole house weatherization and efficiency improvements	Residential	No	No	No
7/19/2018	2018	Advertisement	Email Newsletter	5 Ways to Save During Non-Business Hours	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
7/19/2018	2018	Advertisement	Email Newsletter	Remodeling? Build In Energy Efficiency	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
8/6/2018	2018	Event	Concord	NEC Roundtable with AIA	NH American Institute of Architects energy discussion	TNC/Warren Street Architects	All EE measures	C&I	No	No	No
8/16/2018	2018	Advertisement	Email Newsletter	Video: Improve Comfort & Reduce Costs with Circulating Fans	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
8/16/2018	2018	Advertisement	Email Newsletter	Smarter Living with Smart Thermostats	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
8/25/2018	2018	Training	Remote	Code Webinar - LES/NHSaves	Code Webinar - GDS/DES/NHSaves	Business owners and managers	All EE measures	C&I	Yes	Yes	No
8/27/2018	2018	Advertisement	Online Key Word Search Ads	Programmatic Native	EE Tips Promotion from 8/27 through 10/22	Demo: Homeowners 25+ Geo: New Hampshire	Targeting Tactics: Combination of targeting those searching for relevant content related to saving on energy, cutting costs, etc. as well as retargeting those who visit the website	Residential	No	No	No
9/12/2018	2018	Training	Meredith	Residential Code Workshop	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
9/13/2018	2018	Event	Manchester	The Granite Group Heating Trade Show	Heating Systems Supply House and Heating Contractors show	Plumbing, heating, cooling, water & propane supplies specialists	All EE measures	C&I	No	Yes	No
9/13/2018	2018	Training	Manchester	The Granite Group Heating Trade Show	Heating Systems Supply House and Heating Contractors show	Plumbing, heating, cooling, water & propane supplies specialists	All EE measures	C&I	No	Yes	No
9/18/2018	2018	Training	Gorham	Residential Energy Code Training	NHSaves Presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Joe Harnois of Harber Construction.	Residential	Yes	Yes	No
9/18/2018	2018	Training	Gorham	Residential Energy Code Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Joe Harnois of Harber Construction.	Residential	Yes	Yes	Yes
9/20/2018	2018	Event	Portsmouth	North East Electric Distributers Tradeshow	Electric Supply House and Electrical Contractors show	Electrical distributors, electricians	All EE measures	C&I	No	Yes	No
9/20/2018	2018	Training	Portsmouth	North East Electric Distributers Tradeshow	Electric Supply House and Electrical Contractors show	Electrical distributors, electricians	All EE measures	C&I	No	Yes	No
9/25/2018	2018	Advertisement	Email Newsletter	Smart Thermostats: 5 Benefits for Your Business	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
9/25/2018	2018	Advertisement	Email Newsletter	Fall for Energy Savings	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
9/27/2018	2018	Event	Canaan	Mascoma Valley Energy and Sustainability Expo	Energy related event	Upper Valley town energy committees, building professionals, community members	Weatherization, high efficiency heating	C&I	No	Yes	Yes
9/29/2018	2018	Training	Caanan	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
10/1/2018	2018	Advertisement	Online Key Word Search Ads	Pay Per Click Text Ads	Promote content via ongoing Pay-Per-Click campaign	Residents of NH	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	Paid Facebook & YouTube (Boosted Posts)	Program Awareness and recognition	Demo: Adults 25+, NH homeowners	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	Facebook- Adults 25+ alternative homeowner behavior targeting	Video, Banners, Quiz	Demo: Adults 25+, alternative homeowner behavior targeting	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	Instagram - Adults 25-40 Estimated Audience Size: 130,000	Video, Banners, Quiz	Demo: Adults 25-40 Estimated Audience Size: 130,000	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	YouTube - Adults 18+ Estimated Views: 270,000 - 655,000	(:06) / (:15) Videos	Demo: Adults 18+ Estimated Views: 270,000 - 655,000	All EE measures	Residential	No	No	No

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
10/2/2018	2018	Training	Newmarket	Button Up Workshop	NHSaves Presentation to Newmarket Energy and Environment Advisory Committee, The Newmarket Area Centennial Lions Club and Jonny Boston's International, Plymouth Area Renewable Energy Initiative	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
10/10/2018	2018	Training	Hampton	Residential Energy Code Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Jeffrey Cantara, Solar Design Specialist of ReVision Energy.	Residential	Yes	Yes	No
10/10/2018	2018	Training	Hampton	Residential Energy Code Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Jeffrey Cantara, Solar Design Specialist of ReVision Energy.	Residential	Yes	Yes	Yes
10/16/2018	2018	Training	West Lebanon	C&I Codes Training Workshop	EE program presentation	Builders, architects, contractors and sub-contractors	Building codes	C&I	Yes	Yes	Yes
10/18/2018	2018	Advertisement	Email Newsletter	Coming Up For Air: Improving Combustion Efficiency	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
10/18/2018	2018	Advertisement	Email Newsletter	Slide Show: Simple Steps to Winter Savings & Comfort	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
10/22/2018	2018	Advertisement	Radio	Radio Program Awareness	30 second spot on WHOM, NHPR, WXRV, WFNX, WXRG, WLKC	Residential customers	All EE measures	Residential	No	No	No
10/22/2018	2018	Training	Canterbury	Button Up Workshop	EE Presentation to Canterbury Town Energy Committee, Plymouth Area Renewable Energy Initiative	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
10/24/2018	2018	Advertisement	Social Media	Visual Audit promotion via Facebook and Twitter channels	Highlights and benefits of Visual Audit program	Facebook and Twitter followers	Wi-Fi T-Stats, low flow devices, pipe wrap, LEDs	Residential	No	No	No
10/29/2018	2018	Advertisement	Internet Radio	Pandora	(:30) Audio	Demo: Adults 25+ and home owners, apartment/condo renters & owners Estimated Reach: 113,799	All EE measures	Residential	No	No	No
10/30/2018	2018	Training	Manchester	GDS C&I Codes	Building Energy Codes Workshop	Builders, architects, contractors and sub-contractors	Building codes	C&I	Yes	Yes	Yes
10/30/2018	2018	Training	Concord	NHSAA Conference	Overview of EE programs: NH School administrators association of School Business Officials (NHASBO)	School superintendents	Lighting, HVAC and weatherization	C&I	No	No	Yes
11/1/2018	2018	Training	Holderness	Button Up Workshop	EE Presentation to Holderness Energy Committee, Squam Lakes Association, Plymouth Area Renewable Energy Initiative	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
11/2/2018	2018	Event	Concord	Advanced Manufacturing Conference	NHMEP Governor's Conference	Politicians, energy professionals, business professionals, manufacturing professionals	All EE measures	C&I	No	No	No
11/5/2018	2018	Event	Nashua	NHRLA Annual Dinner	Upgrade Table and Full Page Ad	Restaurant and Lodging Association	All EE measures	C&I	No	No	No

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
11/8/2018	2018	Training	Laconia	Button Up Workshop	EE Presentation to Lakes Region Community College, Plymouth Area Renewable Energy Initiative	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
11/14/2018	2018	Event	Manchester	NHMA Annual Conference	New Hampshire Municipal Association	Municipal officials	All EE measures	C&I	No	No	Yes
11/15/2018	2018	Advertisement	Email	Black Friday Promo for ecobee and Nest Wi-Fi T-Stats	E-blast for Ecobee and Nest manufacturer discounts with Utility rebate special to 64,559 subscribers	Residential gas customers	Wi-Fi T-Stats	Residential	No	No	No
11/15/2018	2018	Event	Manchester	NHMA Annual Conference	New Hampshire Municipal Association	Municipal officials, other non-profits	All EE measures	C&I	No	No	Yes
11/16/2018	2018	Training	Manchester	Compressed Air Training	LU EE and CES Event	Compressed air installers	All EE measures	C&I	No	No	No
11/16/2018	2018	Event	Concord	LES Conference	EE Workshop and 1 pitch to the group	Politicians/lobbyists, non-profits, energy and business professionals	All EE measures	Residential	No	No	Yes
11/20/2018	2018	Advertisement	Email Newsletter	ABC's of Boiler Control	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
11/20/2018	2018	Advertisement	Email Newsletter	Revealed! 6 Hidden Sources of Home Energy Loss	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
11/26/2018	2018	Advertisement	Email	Black Friday Promo for ecobee and Nest Wi-Fi T-Stats	E-blast for Ecobee and Nest manufacturer discounts with Utility rebate special to 64,559 subscribers	Residential gas customers	Wi-Fi T-Stats	Residential	No	No	No
11/27/2018	2018	Training	Rindge/Fitzwilliam	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/28/2018	2018	Training	Lee	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/28/2018	2018	Training	Warren	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/28/2018	2018	Training	Bedford/Hillsborough	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
12/19/2018	2018	Advertisement	Email Newsletter	Boiler Maintenance: 5 Critical Practices for Optimizing Efficiency	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
12/19/2018	2018	Advertisement	Email Newsletter	Is EE on Your Holiday Gift List?	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
12/28/2018	2018	Advertisement	Direct Mail	Home Energy Assistance/Visual Audit Mailer	HEA Mailer detailing program benefits sent to 3,443 low income gas customers	LU natural gas customers coded under the low income rate	Air sealing, insulation, heating systems, appliances, Instant Savings Measures, visual audit	Residential	No	No	No
1/1/2019	2019	Advertisement	Bill Insert	House Feeling Drafty? (NH Saves residential offerings for 2019)	LU delivered to all Gas Customers	LU Gas & Electric Customers	All EE measures	Residential	No	No	No
1/8/2019	2019	Event	Concord	Business After Hours - Concord NH Chamber	Business to Business networking	Small business owners and General Contractors	All EE measures	C&I	No	Yes	No
1/13/2019	2019	Advertisement	Social media	Franklin School project case study	Facebook/Twitter	Local Commercial Online Traffic	All EE measures	C&I	No	No	No
1/17/2019	2019	Advertisement	Email Newsletter	What's the Difference? Direct vs. Indirect Gas-Fired Heaters	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
1/17/2019	2019	Advertisement	Email Newsletter	Infographic: Breaking Down Home Energy Use	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
1/17/2019	2019	Training	Webinar	Virtual NHSaves Button Up Workshop	Weatherization webinar with Q&A session to panel and staff	NH Residents	Weatherization	Residential	No	No	No
1/18/2019	2019	Advertisement	Social media	Online Marketplace Promotion - Smart Thermostat	Facebook/Twitter	LU Customers and Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
1/22/2019	2019	Event	City Hall, Concord	Concord 100% Renewable Energy Strategic Plan Stakeholder Committee Meeting	Discussions on all things energy related.	Non-profits, energy and business professionals	All EE measures	C&I	Yes	Yes	Yes
1/23/2019	2019	Advertisement	Social media	HPwES Program promotion	Facebook/Twitter	Local Residential Online Traffic	Weatherization	Residential	No	No	No
1/24/2019	2019	Advertisement	Social media	Smart Thermostat promotion	Facebook/Twitter	Local Residential Online Traffic	NHSaves Gas	Residential	No	No	No
1/30/2019	2019	Training	Nashua	Training w/Wxn Contractor Turn Cycle Solutions	Surveyor/OTTER	Contractor	HPwES	Residential	No	No	No
1/31/2019	2019	Advertisement	Social media	Online Marketplace promotion of Smart Thermostats	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
1/31/2019	2019	Advertisement	Social media	HPwES Program promotion	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
2/1/2019	2019	Training	Keene State College	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
2/5/2019	2019	Event	State Legislative Office	State Legislative Office - Hearing on HB318	Summary presentation of company's EE programs and efforts ongoing to promote to customers	State Legislature	All EE measures	Both	No	No	Yes
2/7/2019	2019	Advertisement	Social media	Free Energy Savings Measures	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
2/8/2019	2019	Event	Barley House	Concord Chamber of Commerce Local Government Affairs	Business to Business networking	Non-profits, energy and business professionals	All EE measures	C&I	Yes	Yes	Yes
2/13/2019	2019	Training	Roundabout Diner, Portsmouth	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
2/13/2019	2019	Event	Concord	Business After Hours Networking & Promotion event	Business to Business networking	Small business owners and General Contractors	All EE measures	C&I	No	Yes	Yes
2/15/2019	2019	Advertisement	Social media	Smart Thermostat promotion	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
2/15/2019	2019	Training	Concord	14th Annual Small Business Day - NHBIA	Learn about small business solutions	Small business managers	All EE measures	C&I	No	No	No
2/19/2019	2019	Advertisement	Social media	Energy Efficiency Online Tools	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
2/20/2019	2019	Advertisement	Nashua	State of the City Breakfast - Nashua Chamber of Commerce	Update on economic activity with networking following presentation	Business Leaders	All EE measures	C&I	No	Yes	Yes
2/21/2019	2019	Advertisement	Email Newsletter	Video: Maximize Boiler Control with an EMS	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
2/21/2019	2019	Advertisement	Email Newsletter	5 Ways to Start Saving Energy Today	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
2/21/2019	2019	Training	Concord	AIA-NH	Business to Business networking	Architects and General Contractors	All EE measures	C&I	No	No	No
2/22/2019	2019	Advertisement	Social Advertisement	Energy Efficiency Online Tools	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
2/27/2019	2019	Training	Durham	NH Association of School Business Officials-Facilities Masters Conference	School Facilities Managers' topics of interest	Northern New England school facilities managers	All EE measures	C&I	No	No	No
3/1/2019	2019	Advertisement	Bill Insert	Free Energy-Saving Equipment (Visual Audit)	LU delivered to all Gas Customers	LU Gas Customers	All EE measures	Residential	No	No	No
3/1/2019	2019	Training	Puritan Back Room	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
3/8/2019	2019	Training	Doubletree by Hilton, Manchester	New Hampshire State Home Show	Education outreach to contractors and industry associations	NH Residents, Contractors, and Industry Associations	All EE measures	Both	No	No	Yes
3/12/2019	2019	Event	Concord	Business After Hours - Concord NH Chamber	Business to Business networking	Small business owners and General Contractors	All EE measures	C&I	No	No	Yes
3/14/2019	2019	Training	Common Man, Plymouth	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
3/22/2019	2019	Advertisement	Email Newsletter	Save Energy With Efficient Water Heating	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
3/22/2019	2019	Advertisement	Email Newsletter	Home Appliances: The Biggest Energy Users	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
3/25/2019	2019	Training	Pease Tradeport in Portsmouth, NH	Energy Week Event: NH Energy Roundtable	How companies are addressing their energy needs, featuring leading experts & company representatives	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/26/2019	2019	Advertisement	Social media	General EE Post - NH SAVES Partnership	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
3/26/2019	2019	Training	OracleDyn in Manchester	Energy Week Event: Emerging Energy Needs Forum	Discussion on the emerging energy needs in NH's largest city & modern approaches to meeting those needs	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/27/2019	2019	Training	NH CIBOR - Bedford NH	NHCIBOR Statewide Meeting	Discussion about current commercial, industrial and municipal opportunities in the state	Commercial lenders, commercial brokers, and other interested parties	All EE measures	C&I	No	No	No
3/27/2019	2019	Training	City Hall	City of Concord	100% Renewable Energy Strategic Plan Stakeholder Committee Meeting	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/27/2019	2019	Training	Salt Hill Pub in Newport	Energy Week Event: NH Energy Roundtable	Discussion on the emerging energy needs in NH's largest city & modern approaches to meeting those needs	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/28/2019	2019	Training	Grappone Conference Center in Concord	Energy Week Event: NH Energy Breakfast	Discussion with a major offshore wind developer & panel of high-level representatives discussing how the regional grid, energy users, utilities, & generators	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/28/2019	2019	Training	Carriage House, Kimball Jenkins Estatein Concord	Energy Week Event: Awards Ceremony & Reception	NH Energy Awards for Business, Municipal, & Legislative Energy Champions	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/28/2019	2019	Training	Currier Museum of Art	AIA NH Design Awards	35th Annual Excellence in Design Awards	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/1/2019	2019	Advertisement	WGIR AM Radio	Weatherization Radio Advertisement - Winter & Summer Campaign	iHeart Media: recurring radio spot placement from April through December 2019	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Residential	No	No	No
4/2/2019	2019	Training	White Birch Brewing in Nashua	Energy Week Event: NH Energy Roundtable	Local energy stories from businesses & municipalities	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/11/2019	2019	Training	LAARS Manufacturing	ASHRAE CHP Event	Combined heat and power technology, tour of boiler manufacturing facility	Engineers, Manufacturers, distributors	All EE measures	C&I	No	No	No
4/11/2019	2019	Training	Nashua	Turn Cycle Solutions	Surveyor/OTTER	Residential Electric Customers	HPwES	Residential	No	No	No
4/11/2019	2019	Event	Holiday Inn Concord NH	State of the City - Concord Chamber of Commerce	Update on economic activity with networking prior and following presentation	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/15/2019	2019	Advertisement	Social media	Video about HPwES program	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
4/17/2019	2019	Event	Concord City Wide Community Center	Concord Young Professionals Concord Chamber of Commerce	Business to Business networking	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/19/2019	2019	Training	NH Healthcare Association	NHSHFM Monthly Meeting	Building commissioning for healthcare facilities	Healthcare facilities managers, contractors, general contractors	All EE measures	C&I	No	No	No
4/22/2019	2019	Advertisement	Email Newsletter	Boilers: Repair or Replace?	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
4/22/2019	2019	Advertisement	Social media	Earth Day - Thermostat Rebate	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
4/22/2019	2019	Advertisement	E-blast	Smart Thermostats Make Saving Energy Easier	Questline	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
4/22/2019	2019	Advertisement	Email Newsletter	Go Green This Earh Day	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
4/22/2019	2019	Event	Applebee's Nashua	Turn Cycle Solutions	EE program participation and identification of resources	Weatherization contractor	Weatherization	C&I	No	No	No
4/24/2019	2019	Training	FW Webb	Commercial Energy Codes Training	EE program participation and identification of resources	Business Facility Managers and Staff	All EE measures	C&I	Yes	No	No
4/24/2019	2019	Training	NH CIBOR - Bedford NH	NHCIBOR Statewide Meeting	Discussion about current commercial, industrial and municipal opportunities in the state	Commercial lenders, commercial brokers, and other interested parties	All EE measures	C&I	No	No	No
4/30/2019	2019	Training	Londonderry	P&M	Wx 101	Residential Electric Customers	HPwES/HEA	Residential	No	No	No
5/1/2019	2019	Advertisement	Bill Insert	Income Eligible EE Programs & New NH Saves Logo	LU delivered to all Gas Customers	LU Gas Customers	HEA	Residential	No	No	No
5/1/2019	2019	Advertisement	Cable Television	Weatherization Cable TV Advertisement - Winter & Summer Campaign	Comcast: recurring Cable TV spot placement from April through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
5/1/2019	2019	Advertisement	Digital Billboard	Weatherization Digital Billboard Advertisement - Winter & Summer Campaign	Outfront Media: recurring digital billboard placement from May through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
5/1/2019	2019	Advertisement	Community Billboard	Weatherization Community Billboard Advertisement - Winter & Summer Campaign	Outfront Media: recurring community billboard placement from May through December 2019	LU Customers and Local Commercial and Residential Community	HPwES	Residential	No	No	No
5/1/2019	2019	Advertisement	Streaming Radio - Pandora	Weatherization Streaming Radio Advertisement - Winter & Summer Campaign	iHeart Media: recurring online streaming radio advertisement from May through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
5/1/2019	2019	Training	Marriott Courtyard Concord NH	NHBSR Spring Conference	EE program participation and identification of resources	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
5/2/2019	2019	Event	Fitzemeyer & Tocci	Trade Ally Meeting with Fitzemeyer & Tocci	EE program participation and identification of resources	Full service mechanical engineering firm	All EE measures	C&I	No	No	No
5/3/2019	2019	Event	A.W.Rose Construction	Trade Ally Meeting with A.W. Rose Construction	EE program participation and identification of resources	General contractor trade ally	All EE measures	C&I	No	Yes	No
5/3/2019	2019	Event	Jay Lee, Berkshire Hathaway	Commercial Lender Trade Ally	EE program participation and identification of resources	Commercial Broker	All EE measures	C&I	No	No	No

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
5/6/2019	2019	Training	City Hall, Concord	Concord 100% Renewables Listening Session	Discussions on all things energy related.	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
5/9/2019	2019	Training	Mill Brook Primary School	ASHRAE Monthly Meeting	EE program participation and identification of resources	Local engineer trades association	All EE measures	C&I	No	No	No
5/10/2019	2019	Training	Newton	Invictus	EE Program overview	Spray Foam Insulation Contractor and Residential Gas Customers	HPwES	Residential	No	No	No
5/10/2019	2019	Training	Pembroke Readiness Center	2019 State Energy Conference	EE program participation and identification of resources	State facilities staff and administrators	All EE measures	C&I	No	No	Yes
5/14/2019	2019	Event	Manchester	EEI NHSaves program participation and identification of resources	EE program participation and identification of resources	Contractor EEI Representatives	All EE measures	C&I	No	No	No
5/14/2019	2019	Training	Havenwood Heritage Heights	Concord Chamber Business After Hours	EE program participation and identification of resources	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
5/15/2019	2019	Advertisement	Social media	VA Energy Saving Measures and Visual Audit	Facebook/Twitter	Local Residential Online Traffic	Weatherization	Residential	No	No	No
5/16/2019	2019	Training	Franklin	Franklin WWTP Award and Tour	EE program participation	State and municipal staff, and facilities personal	All EE measures	C&I	No	No	Yes
5/17/2019	2019	Event	Lakes Region Chamber of Commerce	EE programs overview presentation	Infrastructure Seminar	State and municipal staff, and facilities personal	All EE measures	Residential	No	No	Yes
5/20/2019	2019	Training	Concord	Turn Cycle Solutions	Blower door training	Contractor	HPwES	Residential	No	No	No
5/21/2019	2019	Advertisement	Email Newsletter	Free Software Calculates Energy Savings of Steam System Insulation	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
5/21/2019	2019	Advertisement	Email Newsletter	5 Ways to Get Your Home Ready for Summer	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
5/22/2019	2019	Advertisement	Email	Promotion of visual audit offeing	Monthly e-newsletter focus	Local Residential Online Traffic	Visual audit	Residential	No	No	No
5/28/2019	2019	Advertisement	Email	Promotion of HPwES program	Monthly e-newsletter focus	Local Residential Online Traffic	HPwES	Residential	No	No	No
5/30/2019	2019	Event	6 Eastpoint Dr., Hooksett	Eckhardt & Johnson	EE Program Participation	HVAC Contractor	All EE measures	C&I	No	No	No
6/1/2019	2019	Advertisement	Bus Wrap	Weatherization Bus Wrap Advertisement - Winter & Summer Campaign	ATA Outdoor Media: recurring bus wrap advertisement from June through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
6/1/2019	2019	Training	Various Locations	Commercial Equipment Heating Equipment Dealer Visits in June	Commercial Equipment Heating Equipment Dealer Visits in June	Deluca Brothers, Kittredge Equipment, NH Restarant Equipment, Perkins/Gordon Food Service, Pitco	Commercial Food Service Equipment (CFSE) rebate program	C&I	No	No	No
6/5/2019	2019	Advertisement	Email	Fathers Day Thermostat Rebate	Special smart thermostat promotion	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
6/5/2019	2019	Training	Derry	Derry Solar Summit	Promotion of EE programs to attendees	Derry Netzero Task Force/municipal staff, and Derry/Londonderry businesses	All EE measures	Both	No	No	Yes
6/6/2019	2019	Event	Concord Chamber of Commerce	EE programs overview presentation	Promotion of EE programs to attendees	State and municipal staff, and facilities personal	All EE measures	C&I	No	No	No
6/6/2019	2019	Training	Concord Chamber of Commerce	Pinnacle Awards	Promotion of EE programs to attendees	State and municiple staff, and facilities personal	All EE measures	Both	No	No	Yes
6/6/2019	2019	Training	Associated Builders & Contractors	ABC Innovation in Education	Municipal Project Focus	Architects, Municipal Staff and General Contractors	All EE measures	C&I	No	Yes	Yes
6/12/2019	2019	Event	Manchester	Oliver Mechanical	Promotion of EE programs to attendees	HVAC Contractor	All EE measures	C&I	No	No	No
6/13/2019	2019	Training	AIA-NH	AIA COTE Summit	Review of EE program eligibility to attendees	NH architects	All EE measures	C&I	No	Yes	No
6/18/2019	2019	Advertisement	Facebook/Twitter	Fathers Day Thermostat Rebate	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
6/18/2019	2019	Advertisement	Email Newsletter	Thermostats: What's the Difference?	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
6/18/2019	2019	Event	Londonderry	Walter F. Morris Company	Promotion of EE programs to attendees	Manufacturers Rep	All EE measures	C&I	No	No	No
6/18/2019	2019	Training	Charlestown	Claremont Spray Foam	Mobile home weatherization	Residential Electric Customers	HEA	Residential	No	No	No
6/19/2019	2019	Training	Newton	Invictus	Surveyor/OTTER	Residential Electric Customers	HPwES	Residential	No	No	No
6/20/2019	2019	Training	Net Zero Task Force	Derry Muni Meeting	Review of EE program eligibility to attendees	Municipal Staff	All EE measures	Both	No	No	Yes
6/21/2019	2019	Training	Municipal Energy Staff,	Sierra Club Municipal Conference	Review of EE program eligibility to attendees	Muni Staff	All EE measures	Both	No	No	Yes
6/26/2019	2019	Advertisement	Facebook/Twitter	HPwES Video - A/C Unit	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
6/26/2019	2019	Event	Business and Economic	NH BEA Meeting	Promotion of EE programs to attendees	State Staff	All EE measures	C&I	No	No	No
6/26/2019	2019	Training	Business and Economic	NH BEA Meeting	Promotion of EE programs to attendees	State Staff	All EE measures	Both	No	No	Yes
6/27/2019	2019	Advertisement	Email	Independence Day Thermostat Rebate Special	Special smart thermostat promotion	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
6/27/2019	2019	Event	6 Eastpoint Dr.,	Eckhardt & Johnson	Promotion of EE programs to attendees	HVAC Contractor	All EE measures	C&I	No	No	No
6/28/2019	2019	Advertisement	Social media	Facebook/Twitter: HPwES Video - A/C Unit	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
6/28/2019	2019	Advertisement	Social media	Facebook/Twitter: 4th of July promo - Google	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
7/2/2019	2019	Advertisement	Social media	4th of July promo - Google Home mini and NEST	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
7/2/2019	2019	Event	CENH Home Office	Clean Energy NH Open House	Networking event	Contractors, manufacturer, distributor, city officials, Architects, engineers	All EE measures	C&I	No	No	Yes
7/2/2019	2019	Training	CENH Home Office	Clean Energy NH Open House	Networking event	Contractors, manufacturer, distributor, city officials, Architects, engineers	All EE measures	C&I	No	Yes	Yes
7/11/2019	2019	Advertisement	Social media	Special Rebates for Gas Customers	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
7/11/2019	2019	Event	Walter F. Morris Company	Joint NHSaves - Walter Morris Flyer	Marketing Meeting	Marketing Staff	All EE measures	C&I	No	No	No

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
7/11/2019	2019	Event	Londonderry	Promotion of EE programs to attendees	Promotion of EE programs to attendees	Marketing Staff	All EE measures	C&I	No	No	No
7/16/2019	2019	Advertisement	Email Newsletter	A Whole Building Approach to EE	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&i	No	No	No
7/16/2019	2019	Advertisement	Email Newsletter	HVAC Systems: 4 Hidden Energy Costs	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
7/16/2019	2019	Advertisement	Facebook/Twitter	HPwES Summer Promotion	Facebook/Twitter	Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
7/16/2019	2019	Advertisement	Email Newsletter	Video: 5 Ways to Save with Smart Home Technology	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
7/18/2019	2019	Training	Johnson's (Northwood)	Lunch meeting w/ Yankee Thermal Imaging	Review of EE program eligibility to attendees	Jamie Polchies- estimator/auditor	All EE measures	C&I	No	No	No
7/19/2019	2019	Event	RBG office	Promotion of EE programs to attendees	Promotion of EE programs to attendees	Don Perrin	All EE measures	C&I	No	No	Yes
7/19/2019	2019	Training	RBG office	Meeting with State of NH	Review of EE program eligibility to attendees	Don Perrin	All EE measures	C&I	No	No	Yes
7/23/2019	2019	Event	Londonderry	USGBC Summer Meet-up	Networking event with LEED professionals	Builders, architects, and designers	All EE measures	C&I	No	Yes	Yes
7/23/2019	2019	Training	Concord	Rotary Presentation	Power point presentation for the Concord Rotary Club	Business owners and municiple leaders	Focus on commercial w/residential included	Both	No	No	Yes
7/23/2019	2019	Training	Concord	Rotary Presentation	Power point presentation for the Concord Rotary	Business owners and municipal leaders	Focus on commercial	Both	No	No	Yes
7/24/2019	2019	Event	Bedford NH	NH CIBOR Statewide Meeting	Promotion of EE programs to attendees	Commercial brokers, bankers,	All EE measures	C&I	No	No	No
7/24/2019	2019	Event	New Canaan	Dave Gooding Company	Educating manufactures rep. on the NHSaves	Trade Ally Contact	All EE measures	C&I	No	No	No
7/24/2019	2019	Training	Bedford NH	NH CIBOR Statewide Meeting	Promotion of EE programs to attendees	Commerical brokers, bankers,	All EE measures	C&I	No	No	No
7/25/2019	2019	Event	F.W. Webb -	Vendor Counter Day	Tabling the F.W. Webb counter and speaking with	Potential Trade Allies	Heating Systems	C&I	No	No	No
7/26/2019	2019	Event	Gilford	NHSHFM Summer Outing	Networking event with Hospital staff and general	Hospital Facilities Directors, and	All EE measures	C&I	No	No	No
7/26/2019	2019	Event	Sunapee	CENH Summer Outing	Networking event with Clean energy membership	Trade Ally Contacts and customers	All EE measures	C&I	No	No	Yes
7/31/2019	2019	Training	Concord	LU Gas audit	Audit of Heritage Harley Davidson	LU Gas Customer	Gas Audit	C&I	No	No	No
8/1/2019	2019	Event	Bedford	Fulcrum Trade Ally Meeting	Meeting With Fulcrum	General contractor trade ally	All EE measures	C&I	No	No	No
8/2/2019	2019	Advertisement	Email	Promotion of visual audit offeing	Promotion of visual audit offering	LU Customers and Local Residential Online Traffic	Visual audit	Residential	No	No	No
8/2/2019	2019	Event	Manchester	Second Wind Water Systems	Meeting with Secondwind Water Systems	Specialty services trade ally	All EE measures	C&I	No	No	No
8/3/2019	2019	Training	New Canaan	Dave Gooding Company	Educating manufactures rep. on the NHSaves program	Trade Ally Contact	All EE measures	C&I	No	No	No
8/5/2019	2019	Training	Windham	Meeting with The Dubay Group	Meeting to review 42 Nashua Road project	Engineer	All EE measures	C&I	No	No	No
8/8/2019	2019	Advertisement	Social media	Explanation of the Energy Audit Process	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
8/8/2019	2019	Training	Derry	NHCIBOR Summer Mixer	Meeting with the commercial realtors and lenders group in central NH	see previous.	All EE measures	C&I	No	No	No
8/8/2019	2019	Training	Manchester	HPwES Energy Audit	On-Boarding Discussion	Invictus	HPwES	Residential	No	No	No
8/13/2019	2019	Training	Concord	REPA - Update on building Codes	Update on newly adopted 2015 building codes with amendments	Energy efficiency companies, and facilities managers	All EE measures	C&I	Yes	No	No
8/14/2019	2019	Event	Concord	Key Account Building Walk-through	Meet with Jason Teaster, facilities director for NH Hospital.	Key Account	All EE measures	C&I	No	No	No
8/14/2019	2019	Event	Concord	Meeting with Peter Mikolaczuk of Air Purchases/ Engel HVAC	NHSaves Program	Territory Manager-HVAC	All EE measures	C&I	No	No	No
8/14/2019	2019	Training	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
8/15/2019	2019	Event	Manchester	Meeting with Freudenberg-NOK	EE program presentation	Kevin Smith, Facilities Manager	All EE measures	C&I	No	No	No
8/16/2019	2019	Training	Lebanon	New Hampshire Society for Healthcare Facilities Managers Seminar	Seminar focused on large energy projects with NH hospitals	Hospital facilities staff	All EE measures	C&I	No	No	No
8/20/2019	2019	Training	Concord	NHSaves Presentation at North Branch	EE program presentation	Program managers, president	All EE measures	C&I	No	No	No
8/21/2019	2019	Training	Concord	ABC Party in the Park	Associated Builders and Contractors summer event	Builders, trade contractors, property management companies	All EE measures	C&I	No	Yes	No
8/22/2019	2019	Training	Manchester	Business After Hours- Manchester COC	TF Moran BAH	Manchester COC, TF Moran, Builders	All EE measures	C&I	No	Yes	Yes
8/27/2019	2019	Training	Concord	Lunch meeting with Anne Copp- Commercial Realtor	EE program training	Anne Copp, Commercial realtor	All EE measures	C&I	No	No	No
8/28/2019	2019	Training	Derry	Meeting with Derry Econ Dev	EE program training	Bev Donovan, Econ Dev Manager	All EE measures	Both	No	No	No
8/28/2019	2019	Training	Concord	Breakfast Club meeting	EE program presentation	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
8/29/2019	2019	Advertisement	Email Newsletter	Simple Steps to Lower Natural Gas Bills	Monthly e-newsletter distribution - 08/29/19	LU Customers and Local Commercial Online Traffic	All EE measures	C&I	No	No	No
8/29/2019	2019	Advertisement	Email Newsletter	Smart Thermostats Make Saving Energy Easier	Monthly e-newsletter distribution - 04/12/19	LU Customers and Local Residential Online Traffic	All EE measures	Residential	No	No	No
9/1/2019	2019	Advertisement	Bill Insert	Promotion of low-coset Energy Savings Measures	LU delivered to all Gas Customers	LU Gas Customers	Visual audit	Residential	No	No	No
9/1/2019	2019	Advertisement	Email	Promotion of low-coset Energy Savings Measures	LU delivered to all Gas Customers with email addresses	LU Gas Customers	Visual audit	Residential	No	No	No
9/10/2019	2019	Event	Nashua	Meeting with Horizon and Invictus	HPwES/Energy Audit	Horizon and Affiliates	HPwES/HEA	Residential	No	No	No
9/10/2019	2019	Training	Nashua	Invictus HPwES Energy Audit	EE Program training	Invictus	HPwES/HEA	Residential	No	No	No
9/11/2019	2019	Training	Concord	Concord Professionals Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
9/11/2019	2019	Training	Concord	Plan NH Business After Hours	Networking	Contractors, etc.	All EE measures	C&I	No	No	No
9/11/2019	2019	Event	Concord	Concord Professionals Breakfast Club Meeting	Networking	Commercial lenders, HVAC distributors, and other members	All EE measures	C&I	No	No	Yes
9/11/2019	2019	Event	Concord	Plan NH Business After Hours	Networking	Commercial lenders, HVAC distributors, and other members	All EE measures	C&I	No	No	Yes

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9/12/2019	2019	Event	Manchester	Granite Group Trade Show	Conference and Networking	HVAC techs, contractors, etc.	All EE measures	C&I	Yes	No	No
9/12/2019	2019	Event	Randolph, MA	GasNetworks Annual Conference	Conference and Networking	HVAC techs, contractors, etc.	All EE measures	C&I	Yes	No	Yes
9/16/2019	2019	Event	Various Locations	2019 Energy Code Workshop Series	Eventbrite Registration - Commercial and Residential Code Series Discussions in September and October	Residential and Commercial Contractors	All EE measures	C&I	Yes	Yes	No
9/16/2019	2019	Event	Manchester	New Contract Response	Total Climate Control	Horizon and Affiliates	HPwES	Residential	No	No	No
9/17/2019	2019	Advertisement	Email Newsletter	Take Building Performance to the Next Level	Article: Take Building Performance to the Next Level	LU Customers and Local Commercial Online Traffic	All EE measures	C&I	No	Yes	No
9/17/2019	2019	Advertisement	Email Newsletter	INFOGRAPHIC: Preparing for a Home Energy Audit	INFOGRAPHIC: Preparing for a Home Energy Audit	LU Customers and Local Residential Online Traffic	All EE measures	Residential	No	No	No
9/17/2019	2019	Event	Concord	NH School Administrators Conference	Energy Summit	Directors of Buildings and Grounds	All EE measures	C&I	No	No	Yes
9/18/2019	2019	Advertisement	Social media	Special Rebates for Gas Customers	Facebook/Twitter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Residential	No	No	No
9/18/2019	2019	Training	Concord	NH School Administrators Conference	Conference & Networking Day 2	Director of Buildings & Grounds	All EE measures	C&I	No	No	No
9/23/2019	2019	Event	Concord	NH Energy Summit	Energy Summit	Energy Industry Professionals	All EE measures	C&I	No	No	Yes
9/24/2019	2019	Training	FW Webb Company Distribution Center, 10 Webb Dr., Londonderry	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Residential Buidling Construction Industry	All EE measures	Residential	Yes	Yes	No
9/25/2019	2019	Advertisement	Social media	Helping Schools and Towns Save through Rebates & Incentives	Facebook/Twitter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	C&I	No	No	No
9/25/2019	2019	Training	Concord	Meeting with Matt Moore- CCSNH	EE Programs training	Dir of Capitol Improvement Projects	All EE measures	C&I	No	No	No
9/25/2019	2019	Event	Derry	Chamber Business Before Hours	Presentation of EE programs	Chamber members and President of Chamber	All EE measures	C&I	No	No	Yes
9/26/2019	2019	Event	Concord	Associated Builders and Contractors	Business after Hours - Young Professional Group - ABC	Contractors, HVAC techs, engineers, etc.	All EE measures	C&I	No	Yes	No
9/26/2019	2019	Training	Manchester	Tri-City Expo	Expo- walked around to vendors	Contractors, property management companies, etc.	All EE measures	C&I	No	No	No
9/26/2019	2019	Training	Concord	ABC YPG BAH	Business After Hours- Young Professional Group- ABC	Contractors, HVAC techs, engineers,etc.	All EE measures	C&I	No	No	No
9/27/2019	2019	Training	Hooksett	NHSaves Lunch & Learn	PROCON Lunch & Learn	Project managers, estimators, etc.	All EE measures	C&I	No	No	No
9/30/2019	2019	Event	Manchester	Jones Boy New Contract Response	New Contract	Horizon and Affiliates	HPwES/HEA	Residential	No	No	No
10/1/2019	2019	Advertisement	Bill Insert	How EE can help your energy bill	LU delivered to all Gas Customers	LU Gas Customers	All EE measures	Residential	No	No	No
10/1/2019	2019	Training	Concord	State of NH Employee Training	Energy Efficiency	Project managers, estimators, etc.	All EE measures	C&I	No	No	No
10/1/2019	2019	Training	The Exeter Inn, 90 Front St., Exeter	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Residential Buidling Construction Industry	All EE measures	Residential	Yes	Yes	No
10/2/2019	2019	Training	Concord	NHSaves Lunch & Learn	HL Turner	Project managers, estimators, etc.	All EE measures	C&I	No	No	No
10/5/2019	2019	Event	669 Union St., Manchester	NHSaves Button Up	UU Fellowship Hall	Homeowners, general public	All EE measures	Residential	No	No	No
10/8/2019	2019	Training	FW Webb Company Distribution Center, 10 Webb Dr., Londonderry	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Commercial Construction Industry	All EE measures	C&I	Yes	Yes	No
10/9/2019	2019	Event	Goffstown	Key Account Meeting	Key Account Meeting with Mike Lencki, Hillsborough County Nursing Home	Purchasing Manager	All EE measures	C&I	No	No	No
10/9/2019	2019	Training	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
10/10/2019	2019	Advertisement	Social media	What does weakening EPA regulations mean?	Facebook/Twitter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Both	Yes	No	No
10/10/2019	2019	Event	Dracut	Key Account Meeting	Key Account Meeting with Bob Norkiewicz, Brox Industries	Plant Manager	All EE measures	C&I	No	No	No
10/10/2019	2019	Training	Church Landing at Mill Falls/Laker Room, 312 Daniel Webster Hwy, Meredith	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Residential Buidling Construction Industry	All EE measures	Residential	Yes	Yes	No
10/10/2019	2019	Training	Concord	Concord Chamber: Building Forum	Discussion about developments in the capital city area	COC members, city officials, architects	All EE measures	C&I	No	Yes	Yes
10/11/2019	2019	Training	Lebanon	Meeting with Atlantic Electrical Distributors	NH Saves Program	Distribution Representatives	All EE measures	C&I	No	No	No
10/15/2019	2019	Advertisement	Email Newsletter	INFOGRAPHIC: Getting Your Facility Ready for Winter	Monthly E-Newsletter	Gas Key Accounts	All EE measures	C&I	No	No	No
10/15/2019	2019	Advertisement	Email Newsletter	Photo Essay: Energy Saving Tips for Fall	Monthly E-Newsletter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Residential	No	No	No
10/15/2019	2019	Training	Woodstock Inn Brewery, 135 Main Street, North Woodstock, NH	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Commercial Construction Industry	All EE measures	C&I	Yes	Yes	No
10/16/2019	2019	Training	Concord	CYPN- Concord Young Professionals	CYPN Networking Night	Young Professionals in various industries, met Steve Duprey, local developer	All EE measures	C&I	No	No	No
10/16/2019	2019	Training	Nashua	Turn Cycle Solutions	Surveyor/OTTER	Contractor and New Staff	All EE measures	Residential	No	No	No
10/17/2019	2019	Training	Hartford, VT	Landlords Energy Efficiency Conference	Meeting of commercial and residential landlords	commercial and residential landlords	All EE measures	Both	No	No	No

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10/18/2019	2019	Training	Nashua	NH Society of Healthcare Facility Managers (NHSHFM)	Gave overview of technically assistance funding to NH hospital facility mangers.	Hospital facility managers	All EE measures	C&I	No	No	No
10/23/2019	2019	Training	Portsmouth	NHSaves Lunch & Learn	TMS Architects - AIA lunch and learn series	Architects	All EE measures	C&I	No	Yes	No
10/24/2019	2019	Event	95 Canal Street, Nashua, NH	BAE Systems Energy Expo	Table at Expo to present NHSaves	BAE Employees	All EE measures	Residential	No	No	no
10/25/2019	2019	Training	Lebanon	Tracy St Multi-Family Ribbon Cutting	Official opening of first net zero affordable housing development in NH	Developer, Contractor, funders, Government Reps	All EE measures	C&I	No	No	Yes
10/31/2019	2019	Training	Concord	Advanced Manufacturing Conference	NHMEP Governor's Conference	Politicians, energy professionals, business professionals, manufacturing professionals	All EE measures	C&I	No	No	Yes
11/1/2019	2019	Advertisement	Bill Insert	Home Feeling Drafty? We Can Help!	LU delivered to all Gas Customers	LU Gas Customers	All EE measures	Residential	No	No	No
11/5/2019	2019	Training	Weatherize Guyz, Derry, NH	Contractor meeting with Horizon	Surveyor/OTTER	Contractor and LU Vendor	HPwES	Residential	No	No	No
11/5/2019	2019	Event	Manchester	CCSNH Meeting at MCC	Review MCC project	Colby Co. Engineering and Matt Moore	All EE measures	C&I	Yes	No	Yes
11/5/2019	2019	Event	Concord	Department of Admin Services Meeting	Status update on projects and future planned projects	Don Perrin	All EE measures	C&I	No	No	Yes
11/8/2019	2019	Training	Invictus Spray, Newton, NH	Contractor meeting with Horizon	Support for HPwES Program Development	Contractor and LU Vendor	HPwES	Residential	No	No	No
11/12/2019	2019	Training	Concord	REPA Meeting- Sense	Training on Sense home monitoring device	Energy efficiency companies, and facilities managers	All EE measures	C&I	No	No	No
11/13/2019	2019	Training	Airport Holiday Inn, Manchester	Efficient Heating and Cooling for Commercial Building Managers	Learn how to control energy costs and maximize EE Incentives	Lakes Region Community College Trainging for Facility Managers, COOs, building operators and sustainability officers	All EE measures	C&I	No	No	No
11/14/2019	2019	Event	Manchester	Municipal Association's 78th Annual Conference	Municipal Association's 78th Annual Conference	Municipal employees	All EE measures	C&I	No	no	Yes
11/15/2019	2019	Advertisement	Email Newsletter	Energy Smart Boiler Maintenance	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	Yes	No
11/15/2019	2019	Advertisement	Email Newsletter	Busted! 3 Common Myths About Home Heating	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
11/15/2019	2019	Training	Concord Grappone Conference Ctr	Clean Energy NH- Local Energy Solutions Conference	Grappone Conference Center	Energy professionals, contractors, business professionals, politicians	All EE measures	C&I	No	Yes	Yes
11/18/2019	2019	Training	Turn Cycle Solutions, Concord, NH	Field Training with Horizon	Energy Audit and work order review; identifying health and safety hazards, thermal imaging and worst case spillage testing.	Contractors and LU Vendor	All EE measures	Residential	No	Yes	No
11/18/2019	2019	Event	Concord	Concord School SAU #8 Meeting	SAU 8 project review	School Officials	All EE measures	C&I	Yes	no	Yes
11/19/2019	2019	Advertisement	LU Website	Black Friday - Thermostats	Social Media	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
11/19/2019	2019	Training	Common Man, Concord	Energy Efficiency for Restaurants and Hopitality	Learn how to control energy costs and maximize NHSaves Incentives	Lakes Region Community College Trainging for Facility Managers, COOs, building operators and sustainability officers	All EE measures	C&I	No	No	No
11/20/2019	2019	Event	Peterborough, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/20/2019	2019	Event	Orange, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/20/2019	2019	Training	Pembroke	State of NH EE Training	EE Training	State employees, facilities managers, building operators, NHSaves employees	All EE measures	C&I	No	Yes	No
11/20/2019	2019	Training	Concord	Energy Efficiency Training- Heating and Cooling- State of NH Employees	HVAC training	State employees, facilities managers, building operators, NHSaves employees	All EE measures	C&I	Yes	no	Yes
11/21/2019	2019	Training	Concord	Community Development Finance Authority (CDFA) Grant Meeting	Grant Applicants training	Grant Applicants	All EE measures	C&I	Yes	Yes	No
11/21/2019	2019	Training	Concord	ASHRAE @ Red Blazer	President of ASHRAE presentation on Integrated Building Design	Local engineer trades association	All EE measures	C&I	No	Yes	Yes

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Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
11/27/2019	2019	Event	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	Yes	No	No
11/27/2019	2019	Training	Conference Call	Non-Lighting Upstream C&I Subcommittee Meeting	4th Wednesday of every month	Joint Utilities	EE Gas Measures	C&I	No	No	No
11/27/2019	2019	Training	Bedford NH	NH CIBOR Statewide Meeting	NHSaves Program	Commerical brokers, bankers, engineers, affiliates	All EE measures	C&I	no	No	No
11/28/2019	2019	Advertisement	LU Website	Black Friday - Thermostats	Social Media	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
12/1/2019	2019	Advertisement	Liberty Utilities - Internal Marketing	Looking to Increase Comfort at Home?	Bill Insert	LU Gas & Electric Customers	EE Gas Measures	Residential	No	No	No
12/4/2019	2019	Event	Gilmanton, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
12/4/2019	2019	Event	Concord	USGBC - NH 10th Anniversary	10th anniversary celebration for NH chapter of the USGBC	Energy efficiency companies, and facilities managers	All EE measures	C&I	no	No	Yes
12/5/2019	2019	Training	Manchester	BIA Energy Symposium	BIA (statewide Chamber of Commerce) Energy symposium. Brought together energy professionals for a day long seminar.	Energy Performance professionals	All EE measures	C&I	No	No	Yes
12/10/2019	2019	Training	Concord	REPA Monthly Meeting	Peter Yost presented on roof venting, etc.	Energy efficiency companies, and facilities managers	All EE measures	C&I	No	Yes	No
12/11/2019	2019	Event	Manchester	CENH Member Holiday Dinner	Annual holiday dinner	Energy Performance professionals	All EE measures	C&I	no	No	No
12/15/2019	2019	Advertisement	Questline	Busted! 3 Common Myths About Home Heating	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
12/15/2019	2019	Advertisement	Questline	Energy Smart Boiler Maintenance	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
12/18/2019	2019	Event	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
12/19/2019	2019	Training	Bedford NH	Franklin Energy Meeting	NH Saves Program	C&I Vendor Reps	All EE measures	C&I	No	No	No
12/20/2019	2019	Training	Manchester	Monthly HEA/HPwES Utility Meeting with Joint Utilities	Discuss Measures for 2020	Joint Utilities	All EE measures	C&I and Residential	No	No	No
12/24/2019	2019	Training	Manchester	Utility Monthly Products Meeting	Discuss Measures for 2020 - 4th Tuesday of Every Month	Joint Utilities	All EE measures	C&I and Residential	No	No	No
1/1/2020	2020	Advertisement	Questline	Wasting Energy is a Hard Habit to Break; 3 Reasons Why Your Furnace Turns on and Off Constantly; Video: You Can Prevent Freezing Pipes; Visual Audit Link	Eblast	Local Residential Online Traffic	EE Gas Measures	Residential	No	No	No
1/1/2020	2020	Advertisement	Questline	Considering a Smart Thermostat? Now's the Time!; Facilities Win with Natural Gas; Infographic: Gas Train Control; Reciprocating Gas Engines Power Hybrid Microgrids; Infographic: Menu fors an Energy-Efficient Kitchen	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	No	No
1/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	NHSAVES: Your Source for Energy Efficiency	Bill Insert	LU Gas Customer	EE Gas Measures	Residential	No	No	No
1/8/2020	2020	Event	F.W. Webb- Concord	Breakfast Club Networking	Networking	Networking	EE Gas Measures	C&I and Residential	Yes	Yes	Yes
1/8/2020	2020	Event	F.W. Webb- Concord	Breakfast Club Networking	Networking	Commercial lender, HVAC distributor, other members	EE Gas measures	C&I and Residential	Yes	Yes	Yes
1/10/2020	2020	Training	Eversource	Energy Park	Preparation for Meetings with VEIC and EESE Board	Joint Utilities	All EE measures	C&I	No	No	No
1/14/2020	2020	Event	Concord	REPA Monthly Training	Air-source heat pumps	Air-source heat pumps	EE Gas Measures	C&I and Residential	No	No	No
1/14/2020	2020	Event	Concord	REPA Monthly Training	Air-source heat pumps	Contractors	EE Gas Measures	C&I and Residential	No	No	No
1/14/2020	2020	Training	Eversource	Small Business Working Session	NH Saves Program Design	Joint Utilities	All EE measures	C&I and Residential	No	No	No
1/15/2020	2020	Event	Bedford	NHCIBOR Meeting	Statewide Marketing Meeting	Statewide Marketing Meeting	EE Gas Measures	C&I and Residential	No	No	No
1/15/2020	2020	Event	Bedford	NHCIBOR Meeting	Statewide Marketing Meeting	Joint Utilities	EE Gas Measures	C&I and Residential	No	No	No
1/15/2020	2020	Training	Eversource	2020 Energy Star Homes Kick Off Meeting	2019 Review and 2020 Goals	Joint Utilities	All EE measures	C&I and Residential	No	No	No
1/16/2020	2020	Training	Merrimack, NH	Wx Crew Training	Blower Door Guided Air Sealing	Contractors	All EE measures	Residential	No	Yes	No
1/17/2020	2020	Event	New London Hospital	NH Society of Health Facility Managers (NHSHFM)	Above-Ceiling Program	Contractors and Facility Representatives	EE Gas Measures	C&I	Yes	Yes	No
1/17/2020	2020	Event	New London Hospital	NH Society of Health Facility Managers (NHSHFM)	Above-Ceiling Program	Above-Ceiling Program	EE Gas Measures	C&I	Yes	Yes	No
1/21/2020	2020	Advertisement	Newsletter	Considering a Smart Thermostat	Questline	Questline	EE Gas Measures	Residential	No	No	No

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As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
1/24/2020	2020	Event	Concord	Breakfast with Joe Campbell (North Branch)	Review of NHSaves programs, 2020 program, etc.	Commercial lender, HVAC distributor, other members	EE Gas Measures	C&I	Yes	Yes	No
1/24/2020	2020	Event	Manchester	NH Foodbank Walk-Through and Presentation	Walk-through and presentation to Chefs and COO	Joint Utilities	EE Gas Measures	C&I	Yes	No	No
1/24/2020	2020	Event	Concord	Breakfast with Joe Campbell (North Branch)	Review of NHSaves programs, 2020 program, etc.	Review of NHSaves programs, 2020 program, etc.	EE Gas Measures	C&I	Yes	Yes	No
1/24/2020	2020	Event	Manchester	NH Foodbank Walk-Through and Presentation	Walk-through and presentation to Chefs and COO	Walk-through and presentation to Chefs and COO	EE Gas Measures	C&I	Yes	No	No
1/24/2020	2020	Event	Bedford	Breakfast with Marie (AFE Chair)	Networking, review of AFE trade group	AFE Trade Group	EE Gas Measures	C&I	No	No	Yes
1/24/2020	2020	Event	Bedford	Breakfast with Marie (AFE Chair)	Networking, review of AFE trade group	Networking, review of AFE trade group	EE Gas Measures	C&I	No	No	Yes
1/25/2020	2020	Advertisement	Facebook/Twitter	Button Up Workshop - Wilmot	Social Media	Social Media	EE Gas & Electric Measures	Residential	No	No	No
1/25/2020	2020	Event	Wilmot, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
1/29/2020	2020	Event	Derry	Association for Facilities Engineering	Monthly Meeting	Joint Utilities and Contractors	EE Gas Measures	C&I	No	No	Yes
1/29/2020	2020	Event	Derry	Business After Hours	Monthly Networking	Small business owners and General Contractors	All EE measures	C&I	No	No	Yes
1/29/2020	2020	Event	Derry	Association for Facilities Engineering	Monthly Meeting	Monthly Meeting	EE Gas Measures	C&I and Residential	No	No	Yes
1/29/2020	2020	Event	Derry	Business After Hours	Monthly Networking	Monthly Networking	EE Gas Measures	C&I and Residential	No	No	Yes
2/1/2020	2020	Advertisement	Questline	5 Ways to Lower Your Heating Costs; 4 Reasons Why Your Filter Isn't Filtering Air; Power Play: Energy Crossword Puzzle; Visual Audit Link	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
2/1/2020	2020	Advertisement	Questline	The Rising Stars of Natural Gas; Switching to Natural Gas Vehicles: Advice from the Experts; Process Heating: Identifying and Reducing Energy Waste; Who Wants To Be An Energy Expert? Natural Gas;	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
2/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	House Feeling Drafty? We Can Fix That	Bill Insert	LU Gas Customers	EE Gas Measures	Residential	No	No	No
2/1/2020	2020	Advertisement	Bill Insert residential gas customers	Home Performance with ENERGY STAR	Promoting the HPwES program	Residential gas customers	air sealing, imsulation, ISMs	Residential	No	No	No
2/1/2020	2020	Event	Newbury, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/4/2020	2020	Event	Concord	InTown Concord Town Hall Meeting	Town Hall Meeting- Façade Grant Program	Town Hall Meeting- Façade Grant Program	EE Gas Measures	C&I and Residential	No	No	Yes
2/5/2020	2020	Event	Laconia	Lakes Region Community Developers- Compass House Ribbon Cutting	Ribbon Cutting- Compass House	Ribbon Cutting- Compass House	EE Gas Measures	C&I and Residential	No	No	Yes
2/8/2020	2020	Event	Grantham, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/11/2020	2020	Event	Concord	REPA Monthly Training	Energy Efficiency Policy (EERS)	Energy Efficiency Policy (EERS)	EE Gas Measures	C&I and Residential	No	No	No
2/14/2020	2020	Event	Concord	NH Small Business Day	BIA Small Business Day	BIA Small Business Day	EE Gas Measures	C&I	No	No	Yes

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
2/15/2020	2020	Event	New London, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/15/2020	2020	Event	Concord	Concord City Energy & Environment Advisory Committee meeting	Energy & Environment Advisory Committee Meeting	Energy & Environment Advisory Committee Meeting	EE Gas Measures	C&I	Yes	No	Yes
2/19/2020	2020	Event	North Andover, MA	AFE Monthly Meeting	Boston Med Flight Tour	Boston Med Flight Tour	EE Gas Measures	C&I	No	No	Yes
2/20/2020	2020	Event	Hooksett	BNI Meeting	NE Tap House Grille	NE Tap House Grille	EE Gas Measures	C&I	No	No	Yes
2/21/2020	2020	Event	Newington	NHCIBOR- Seacoast Marketing Meeting	NHCIBOR Meeting	NHCIBOR Meeting	EE Gas Measures	C&I	No	No	Yes
2/22/2020	2020	Event	New London, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/24/2020	2020	Advertisement	Sidebar in Questline e-newsletter	Visual audit	Promoting the visual audit	Residential gas customers	Wi-Fi T-Stat, LEDs, water saving measures, piep wrap	Residential	No	No	No
2/26/2020	2020	Event	Milford	HBP New Hampshire Trade Show	Harvey Building Products, Trade Show	Harvey Building Products, Trade Show	EE Gas Measures	C&I	Yes	Yes	No
2/26/2020	2020	Event	Bedford	NHCIBOR	NHCIBOR Meeting	NHCIBOR Meeting	EE Gas Measures	C&I	No	No	Yes
2/26/2020	2020	Event	Salem	NNEFMC (Northern New England Facility Masters Conference)	Conference for school facility managers	Conference for school facility managers	EE Gas Measures	C&I	Yes	No	Yes
3/1/2020	2020	Advertisement	Questline	Energy Monitoring Systems Provide Real-Time Savings; Office Buildings: Energy and Cost Saving Strategies; Cybersecurity: Are Your Systems Up to Standard; 4 Women Who Changed the Tech Industry	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
3/1/2020	2020	Advertisement	Questline	Energy Monitoring Systems Provide Real-Time Savings; 5 Key Safety Measures for CNG Vehicle Maintenance Facilities; The Benefits of Boiler Condensate Recovery; 4 Women Who Changed the Tech Industry	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
3/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	Free Energy Saving Equipment	Bill Insert	LU Gas Customers	EE Gas Measures	Residential	No	No	No
3/4/2020	2020	Event	Manchester	NH Business for Social Responsibility (NHBSR) Awards Night	Sustainability Awards Event	Sustainability Awards Event	EE Gas Measures	C&I	No	No	Yes
3/5/2020	2020	Event	Concord	NHSaves Business Partner Rollout	NHSaves event	NHSaves event	EE Gas & Electric Measures	C&I	Yes	Yes	No
3/10/2020	2020	Event	Concord	REPA Monthly Training	Installation of fenestration products & 475 High Performance Building Supply	Installation of fenestration products & 475 High Performance Building Supply	EE Gas Measures	C&I and Residential	No	Yes	No
3/11/2020	2020	Event	Concord	Breakfast Club Networking	Networking	Networking	EE Gas Measures	C&I and Residential	No	Yes	Yes
4/1/2020	2020	Advertisement	Questline	NH EE Covid-19 Contingency Plan; 6 Ways to Save this Spring; Money Savers Low Flow Showerhead;Keep This Planet Green for Me and You	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
4/1/2020	2020	Advertisement	Questline	Covid-19 Information; Steam Systems: Keep the Pressure On and Save; CNG: Powering the Fleets of Tomorrow; 3 Options for Natural Gas Cooling; 811: Call Before You Dig	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
4/23/2020	2020	Advertisement	Questline	We Are Here With You - Ecobee Earth Day - Rebate Incentive Program	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
5/1/2020	2020	Advertisement	Questline	Covid-19 Information; Get Your House in Shape for Summer; Do You Need a Thermostat Adjustment?; Do's and Don'ts: Using the Dishwasher; Ready to Dig? Call 811	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
5/1/2020	2020	Advertisement	Questline	Covid-19 Information; Stay Cool with Natural Gas; Combined Heat and Power Without the Investment; Double-Effect Absorption Chillers: A Breakdown; Excess Air in Gas Burners: How Much is Too Much?	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
5/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	Weatherization on a Budget	Bill Insert	LU Gas Customers	EE Gas Measures	Residential	No	No	No
6/1/2020	2020	Advertisement	Questline	Summer Living: Staying Cool Upstairs is a Breeze; Do Dishwashers Use More Energy Than Hand Washing? Weather Wisdom: Temperature and Sleep; Fact or Fable? Summer Solstice	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
6/1/2020	2020	Advertisement	Questline	Microgrids Power Up with Natural Gas; Cooling Problems? Natural Gas Can Solve Them; Capture Savings with Drain Water Heat Recovery; Safety First: Using Natural Gas in the Workplace	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No

WNA Tracking 2018-2019

Date	Call Type	Inquiry Details	Follow Up	Representative	Additional Comments	F.A.Q.'s Reference	Resolved
14-Feb	Inquiry	Why this program?	N/A	R.Scott	Asked if they would see the charge every month.	Are there any added benefits to decoupling?	Complete
18-Feb	Inquiry	Why this program?	N/A	T.Grant	Customer did understand why we were charging him	What is Revenue decoupling?	Complete
20-Feb	Inquiry	Hard to Understand	N/A	J.Colon	Didn't understand why we were crediting him	What is Revenue decoupling?	Complete
2-Mar	Inquiry	Why this program?	N/A	A.Reilly	Went over charges	How will this affect my bill?	Complete
3-Mar	Complaint	Escalation in Disagreement	N/A	A.Yusuf	Upset about how much the WNA "cost" for her	What is the main purpose of decoupling?	Complete
5-Mar	Inquiry	When will it start?	N/A	R.Scott	Never noticed it on the bill, questions about program.	What is Revenue decoupling?	Complete
6-Apr	Inquiry	What is this program?	N/A	R.Scott	Wanted to know if the program was optional or not	How does decoupling work?	Complete
22-Apr	Inquiry	What is this program?	N/A	K.Burroughs	Customer wanted to know what the charges were for?	What is the main purpose of decoupling?	Complete

WNA Tracking 2018-2019

Date	Call Type	Inquiry Details	Follow Up	Representative	Additional Comments	F.A.Q.'s Reference	Resolved
13-Nov	Inquiry	Hard to Understand	N/A	M.Grant	Thinks we should just increase the customer charge year round and that might make more sence to the customers	What is the main purpose of decoupling?	Complete
13-Nov	Inquiry	What is this program?	N/A	J.Roberts	Wanted to know more about the program, understands and found interesting	What is Revenue decoupling?	Complete
21-Nov	Inquiry	Why this program?	N/A	J.Brouillet	Why this program? Why not increase the customer charge year round? No follow up need- preferred the customer charge increase	Are there any added benefits to decoupling?	Complete
30-Nov	Inquiry	What is this program?	N/A	J.Brouillet	Questions on how the program works	How does decoupling work?	Complete
5-Dec	Inquiry	What is this program?	N/A	K.Burroughs	When reviewing usage for November, during high bill complaint, questioned the credit on account	How will this affect my bill?	Complete
6-Dec	Inquiry	Why this program?	N/A	N.Soucy	Concerned that the credits/debits are based on usage and not a flat rate for budgeting purposes	Is my bill still based on how much gas I use?	Complete
6-Dec	Inquiry	What is this program?	N/A	A.Cook-Dodge	Customer wanted more information on what the program was about	What is Revenue decoupling?	Complete
6-Dec	Complaint	When will it start?	Supervisor Call Back	A.Cook-Dodge	Wanted to know why it was on one bill and not another. See breakdown on tab A10 by Joanne Iovino		Complete
7-Dec	Inquiry	What is this program?	N/A	D.Duchaine	Wanted to know when this started and if other companies are participating too	Is decoupling a new concept?	Complete
11-Dec	Inquiry	What is this program?	N/A	D.Pisco	Why do I have this charge on the bill? Will I always get it?	How will this affect my bill?	Complete
12-Dec	Inquiry	What is this program?	N/A	A.Cook-Dodge	Curious as to why he had a credit on his account	What is Revenue decoupling?	Complete
12-Dec	Inquiry	Why this program?	N/A	A.Cook-Dodge	How long will the program last?	How will this affect my bill?	Complete
10-Dec	Inquiry	What is this program?	N/A	A.Maggio	Wanted to know more about the program, happy with credit	What is Revenue decoupling?	Complete
18-Dec	Inquiry	What is this program?	N/A	K.Ripaldi	Asked why he had a credit on his bill	How will this affect my bill?	Complete
3-Jan	Inquiry	Hard to Understand	N/A	A.Maggio	Didn't see the charge on the bill, walked customer through the fact that it was the credit. Refered to website for additional details as well.	What is Revenue decoupling?	Complete
16-Jan	Inquiry	What is this program?	N/A	A.Maggio	Wanted to know why there was a credit on his bill that he has never seen before	How will this affect my bill?	Complete
16-Jan	Inquiry	What is this program?	N/A	A.Maggio	Wanted to know more about the program and why he had a credit on his account	What is Revenue decoupling?	Complete
12-Feb	Inquiry	Why this program?	N/A	A.Cook-Dodge	Wanted to know what the charges on the bill were	What is Revenue decoupling?	Complete
1-Mar	Inquiry	What is this program?	N/A	J.Roberts	Wanted to know why he got a credit on his bill	What is Revenue decoupling?	Complete

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 21-130

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

UPDATED DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

October 19, 2021

Liberty

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I. INTRODUCTION

Q. Please state your full name and business address.

A. (DS) My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

(CM) My name is Catherine A. McNamara. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("LUSC"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("EnergyNorth" or "the Company").

Q. Please describe your educational background and your business and professional experience.

A. (DS) (CM) Please see our Direct Testimony, filed September 15, 2021, for our educational backgrounds and business and professional experience.

Q. Mr. Simek and Ms. McNamara, have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. Yes, we have.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's updated proposed firm sales cost of gas rates for the 2021/2022 Winter (Peak) Period and the Company's proposed 2021/2022 Local Delivery Adjustment Clause, both effective November 1, 2021. Our testimony also explains the Company's updated proposed firm sales cost of gas rates for the 2022 Summer (Off-Peak) Period.

II. <u>WINTER 2021/2022 COST OF GAS FACTOR</u>

Q. What are the proposed firm Winter sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $1.1339 per therm for residential customers, $1.1341per therm for commercial/industrial high winter use customers, and $1.1324 per therm for commercial/industrial low winter use customers as shown on Proposed Second Revised Page 95 (Bates 056). The Company proposes a firm transportation cost of gas rate of $0.0002 per therm as shown on Proposed Second Revised Page 98 (Bates 058).

Q. Please explain tariff page Proposed Second Revised Page 95 (Bates 056).

A. Proposed Second Revised Page 95 contains the calculation of the 2021/2022 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 95, the proposed 2021/2022 Average Cost of Gas of $1.1339 per therm is derived by adding the Direct Cost of Gas Rate of $1.0843 per therm to the Indirect Cost of Gas Rate of $0.0496 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Proposed Second Revised Page 95, is $94,810,891. The estimated Indirect Cost of Gas, also derived on Page 95, is $4,338,002. The Direct Cost of Gas Rate of $1.0843 and the Indirect Cost of Gas Rate of $0.0496 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 87,443,741 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Proposed Second Revised Page 96 (Bates 057), total $161,141. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $94,649,751 to determine the Total Anticipated Direct Cost of Gas of $94,810,891(slightly off due to rounding).

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Second Page 96 (Bates 057) consists of the following components:

1.	Purchased Gas Demand Costs	$12,887,000
2.	Purchased Gas Commodity Costs	72,351,034
3.	Storage Demand and Capacity Costs	981,898
4.	Storage Commodity Costs	6,130,435
5.	Produced Gas Cost	2,299,384
	Total	$94,649,751

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Second Page 96 (Bates 057), are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$1,431,639
2.	Interest	44,085

3.	Fuel Inventory Revenue Requirement	335,667
4.	Broker Revenues	(3,600)
5.	Transportation COG Revenue	(6,938)
6.	Capacity Release Margin	(1,676,512)
7.	Fixed Price Administrative Cost	36,800
	Total Adjustments	$,161,141

These allowable adjustments are standard adjustments made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. We discuss the factors contributing to the prior period under collection later in this testimony.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in Docket No. DG 20-141 for the 2020/2021 winter period?

A. The average cost of gas rate proposed in this filing of $1.1339 per therm is $0.5768 per therm more than the initial rate of $0.5571 per therm approved by the Commission in Order No. 26,419 (October 30, 2020) in Docket No. DG 20-141. The $0.5768 per therm increase in the rate is primarily due to a $48,513,696 increase in the Total Unadjusted Direct Cost of Gas.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2020/2021 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0002 per therm. The rate approved in Docket No. DG 20-141 was $0.0001 per therm. There is a $0.0001 increase in the firm transportation rate.

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. No. The pressure support purposes rate of 8.7% stayed the same based on the marginal cost study used for the rate design approved in Docket No. DG 20-105.

Q. Did the Company include a fuel inventory revenue requirement calculation in this filing?

A. Yes. The calculation is provided on Schedule 26 (Bates 207). The Company is proposing to collect $335,667 in fuel inventory revenue requirement consistent with the approved rate of return in Order No. 26,505 (July 30, 2021) in Docket No. DG 20-105. The impact of this amount to the overall Cost of Gas rate is $0.0038 per therm, which is determined by dividing the $335,667 by the estimated November 2021 through October 2022 COG sales volumes of 87,443,741 therms.

Q. How was the statutory tax rate of 27.08% on Schedule 26 calculated?

A. The statutory rate of 27.08% was calculated by using a 21% federal tax rate and a 7.7% tax rate for the State of New Hampshire (0.21 + 0.077 – (0.21 x 0.077) = 0.27083).

Q. How was the common equity pre-tax rate of 6.640% on Schedule 26 calculated?

A. The common equity pre-tax rate of 6.640% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 20-105, by 0.72917 (1 – 0.27083) [statutory tax rate – see previous question] and multiplied by 52.00% (equity component of the capital structure approved in DG 20-105) [0.093 / 0.72917 x 0.5200 = 0.06664].

Q. Has the bad debt percentage in this filing of 0.700% changed from the bad debt percentage calculated in the Winter 2020/2021 Cost of Gas Reconciliation?

A. Yes. The bad debt percentage of 0.70% used in this filing is the calculated rate for the period of May 2020–April 2021. The bad debt percentage that was calculated in the Winter 2020/2021 Cost of Gas Reconciliations for the period of May 2019–April 2020 was 1.1%.

Q. What was the actual weighted average firm sales cost of gas rate for the 2020/2021 winter period?

A. The weighted average cost of gas rate was $0.5100 per therm (Bates 104, line 54). This was calculated by applying the actual monthly cost of gas rates for November 2020 through April 2021 to the monthly therm usage of an average residential heating customer using 667 therms for the six winter period months.

Q. What is the current percentage used to calculate the maximum increase to the Cost of Gas rate?

A. The current percentage used to calculate the maximum allowed increase to the Cost of Gas rate is 25% for both Winter and Summer period Cost of Gas rates.

Q. Is the Company requesting an increase to the percentage used to calculate the maximum allowed Cost of Gas Rate?

A. Yes, the Company is requesting that the percentage used to calculate the maximum allowed cost of Gas rate be increased for the Summer period of May through October.

The Company is not requesting a change to the maximum allowed percentage increase applicable to the Winter period.

Q. Why is the Company asking that the percentage used to calculate the maximum allowed cost of Gas rate be increased for the summer period of May through October?

A. In the past eighteen summer months (i.e., the last three Summer periods) the Company has been at the maximum allowed rate for twelve of those months. In the summer of 2021, the Company has been at the maximum allowed rate for all six months. The under collected balance has grown to approximately $4.5M. That under collection is the beginning balance for the summer portion of this filing. In the summer of 2020, the Company's calculated Cost of Gas rate was at the maximum allowed rate for three out of the six months and the under collected balance grew to $3.5M but was primarily offset by an out of period accounting adjustment. Given these circumstances, the Company believes the 25% used to calculate the maximum allowed Cost of Gas rate is insufficient. While the 25% maximum increase was appropriate in prior years when there was a separate filing for the Summer Cost of Gas rate, once the Winter and Summer periods were combined into one filing, the amount of time between the filing and the effective date for the Summer Cost of Gas rate increased by six months, thus increasing the likelihood of the forecasted Summer Cost of Gas rate differing significantly from the market conditions during the applicable summer period. One of the reasons for having a "trigger" adjustment to the Cost of Gas rate it to try to reduce potential under collections at the end of the rate period. As shown by the size of the under collections during the recent summer periods, the 25% limit has been insufficient to serve that purpose.

Q. What percentage used to calculate the maximum allowed Summer Cost of Gas Rate is the Company asking for approval of?

A. The Company is asking for the percentage used to calculate the maximum allowed Summer Cost of Gas rate to be increased from 25% to 40%.

Q. How did the Company determine that an increase of the maximum allowed Summer Cost of Gas from 25% to 40% was appropriate?

A. The Company did an analysis of the past four years. We started with the original summer cost of gas monthly adjustment filings, removed out of period adjustments and then calculated what the four-year average increase would have been if we were able to increase the rates beyond 25%. The average increase was 47.2%. We then rounded down to 40%.

Q. Why should the Commission increase the percentage used to calculate the maximum allowed Cost of Gas rate for the Summer period?

A. When the Company reaches the maximum allowed rate, the under collected balance continues to grow. In the summer of 2021, the projected under collected balance is $4,472,186. Based on the 2022 estimated summer therms of 27,125,444, the rate for next summer will be starting with an increase of $0.1649 per therm just to recover that under collection. The Commission should approve the increased percentage used to calculate the maximum allowed Summer Cost of Gas because the only other option is the

Company would be forced to file for additional rate increase approvals which would defeat the purpose of having a single annual Cost of Gas filing

Q. Why doesn't the Company make an interim filing when the maximum allowed Cost of Gas is reached?

A. An additional filing would be an administrative burden for all parties. The primary reason for combining the winter and summer filing into one, was to reduce this administrative burden.

Q. Is the 25% used to calculate the maximum allowed Cost of Gas sufficient for the Winter period?

A. Yes, the 25% used to calculate the maximum allowed Cost of Gas increase, in the winter period, is sufficient. The volume of therms sold is approximately 40% higher than the amount of therms sold during the summer months. The same $4.5M under collection referenced above would cause an automatic increase of only $0.0519 per therm during the winter. Also, rates for the Winter Cost of Gas are calculated using more near-term market information than those for the future Summer period.

III. PRIOR WINTER PERIOD UNDER-COLLECTION

Q. Please explain the prior period under collection of $1,431,639.

A. The prior period under-collection is detailed in the 2020/2021 winter period reconciliation that was filed with the Commission on July 29, 2021. The $1,431,639 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2021. The under-collection was driven mainly by the lag in the timing of monthly cost of gas rate adjustments as compared to changes in the underlying costs.

IV. FIXED PRICE OPTION

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?

A. Yes. Pursuant to Order No. 24,515 in Docket No. DG 05-127, the Fixed Price Option Program ("FPO") rates are set at $0.0200 per therm higher than the initial proposed COG rate. Proposed Second Revised Page 94 (Bates 055) contains the FPO rate for the 2021/2022 winter period, which is $0.9256per therm for residential customers. This compares to the FPO rate approved for the 2020/2021 winter period of $0.5771 per therm for residential customers. This represents a $0.3485 per therm or 60.4% increase in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 667 therms is an increase of approximately $232.45 or 60.4% compared to last winter's approved FPO rate. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $138.94(or 22.5%) lower than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 (Bates 204) contains the historical results of the FPO program.

V. LOCAL DELIVERY ADJUSTMENT CLAUSE ("LDAC")

Q. What are the surcharges that will be billed under the LDAC?

A. As shown on Proposed Second Revised Page 101 (Bates 061), the Company is submitting for approval an LDAC of $0.1444 per therm for the residential non-heating class and residential heating class, and $0.0878 per therm for the commercial/industrial bundled sales classes, effective November 1, 2021. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Factor, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Gas Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 20-105.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2021, through October 31, 2022, forecasted Keene therm sales of 1,405,237 are added to the EnergyNorth therm sales forecast of 181,424,635 for a total therm sales forecast of 182,829,872.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for the November 2021 through October 2022 period. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period under-recovery of the Company's residential and commercial energy efficiency programs as of October 2021. As shown on Schedule 19 Energy Efficiency (Bates 132–134), the proposed Energy Efficiency charge is $0.0861 per therm for residential customers and $0.0408 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Factor ("RDAF").

A. The purpose of the RDAF is to recover or refund, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. Schedule 19 RDAF Page 3 (Bates 130) shows the prior period difference (September 2020 through August 2021) between the proposed Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation of a total under-collection of $2,426,364. Schedule 19 RDAF Page 2 (Bates 129) also includes a reconciliation of the amount of prior refunds (accumulated through October 2020 and refunded November 2020 through August 2021) of $969,938 remaining to be refunded.

Q. Did the Company's original filing on September 1, 2021, filing include a schedule showing the calculation of the reconciliation of allowed and actual revenues related to what was formerly known as the Residential Low Income Assistance Program ("RLIAP")?

A. Yes. In that original filing, the Company included Schedule RDAF Page 4 which provided a calculation of a total amount of $4,024,830 which, due to a lack of clarity in the tariff which resulted in a mismatch between allowed and actual revenues associated with the R-4 rate class, had been inappropriately refunded to customers over the prior two decoupling years. Specifically, the amounts for each year were $1,932,224 for the 2019/2020 year and $2,092,605 for the 2020/2021 year. The Company's original filing had initially sought to recover the $4,024,830 over a two-year period beginning November 1, 2021. However, as discussed in various pleadings in this docket, it is clear that the issue warrants further investigation and discussion among the parties. Thus, the

Company is requesting that the issue remain in this proceeding but on a different schedule to allow for that further examination and a later hearing. Liberty notes that this request is similar to an alternative set forth by the Department of Energy in its October 14, 2021, motion in this proceeding. Consistent with the preceding discussion, the Company has retained Schedule RDAF Page 4 in this updated filing but has removed its request for recovery to begin on November 1 and the associated rate impacts from the associated rate schedules. The Company maintains its request to recover this amount, but does not object to a later effective date to allow for further review and investigation.

Q. Does the mismatch described above impact the current reconciliation period related to revenues associated with the Gas Assistance Program ("GAP")?

A. No. As a result of changes to the tariff that were approved in Docket No. DG 20-105, revenue per customer used in the allowed revenue calculations are no longer different from residential customers not categorized as GAP and, thus, the allowed and actual revenues for the R-4 customer class are in alignment.

Q. What is the proposed Gas Assistance Program charge?

A. As shown on Schedule 19 Gas Assistance (Bates 135–136), the proposed GAP charge is $0.0156 per therm. This charge is designed to recover administrative costs, revenue shortfall resulting from the GAP discount, and the prior period reconciliation adjustment relating to this program. For the 2021/2022 winter period, the Company is providing a 45% base rate and cost of gas discount, consistent with the settlement agreement approved by the Commission in Order No. 26,397 (August 27, 2020) in Docket No. DG 20-013. The proposed Residential Gas Assistance charge is designed to recover

$2,849,123, of which $2,640,884 is for the revenue shortfall resulting from 5,320 customers receiving a 45% discount off their base and cost of gas rates, and $208,239 for the prior year reconciling adjustment.

Q. In Order No. 24,824 (Feb. 29, 2008) in Docket No. DG 06-122 relating to short-term debt issues, the Company agreed to adjust its short-term debt limits each year as part of the Company's Winter Period Cost of Gas filing. Did the Company calculate the short-term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Schedule 24 (Bates 205) the short-term debt limit for fuel and non-fuel purposes for the 2021/2022 winter period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2021, through October 31, 2022, is calculated to be $29,744,668 and the limit for non-fuel purposes is calculated to be $115,471,436.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 95)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism, as well as the third-party recoveries, are included in the Environmental Cost Summary in Schedule 20 (Bates 138) of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Casey in her pre-filed direct testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Schedule 20. The Summary included in Schedule 20 shows the remediation cost pools for the Concord Pond, Concord MGP, Manchester, Nashua, and Laconia sites, and a General Pool for costs that cannot be directly assigned to a specific site.

A summary sheet and detailed backup spreadsheets that support the 2020/2021 costs are provided in Schedule 20 of this filing. Ms. Casey's testimony describes the Company's activities with regard to all five sites.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2021, and ending October 31, 2022, is $0.0155 per therm. Consistent with filings made over the past few years, this surcharge will recover a total of $2,832,222 in amortized remediation costs. The amortized actual to forecast true-up recovery costs through June 2019 of $341,389 (total amount is $1,024,167 which is amortized over three years). The $1,024,167 is the amount approved by Order No. 26,419 in Docket No. DG 20-141. Also, the actual to forecast true-up recovery cost for the period July 2020 through June 2021 is $139,028. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing.

Q. Did the Company include a Rate Case Expense (RCE) surcharge in this filing?

A. Yes. As shown on Schedule 19 RCE (Bates 126–127), the Company is proposing to collect $2,214,505 in uncollected rate case and recoupment expense consistent with Order No. 26,505 (July 30, 2021) in Docket No. DG 20-105. The RCE rate of $0.0121 per therm is determined by dividing the $2,214,505 by the estimated November 2021 through October 2022 sales volumes of 182,829,872182,829,875 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2021 through October 2022 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 206) the Company has recalculated its Company Allowance for the period November 2021 through October 2022. The Company calculated the Company Allowance of 1.22% based on sendout and throughput data for the twelve-month period ending June 2021. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2021.

VI. CUSTOMER BILL IMPACTS

Q. What are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's winter bill as compared to the winter rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 (Bates 104) of this filing. These bill impacts reflect the implementation of the increases approved in Docket No. DG 20-105 effective August 1, 2021, relating to the EnergyNorth distribution rate case. The total bill impact over the winter period for an average residential heating customer is an increase of approximately $469.43 or 55.15%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is an increase of approximately $1,293.37 or 60.32% (Bates 105). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed Second Revised Page 153 (Bates 062) relating to Supplier Balancing and Peaking Demand Charges and Proposed Second Revised Page 154 (Bates 063) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 153.

A. In Proposed Second Revised Page 153 (Bates 062), the Company is updating the Peaking Demand Charge from $17.32 per MMBtu of Peak MDQ to $54.72 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 187–197).

Q. Please describe the changes to tariff Page 154.

A. Proposed Second Revised Page 154 updates the Capacity Allocator percentages used to allocate pipeline, storage, and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 (Bates 198–203) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2021 COST OF GAS FACTOR

Q. What are the proposed 2022 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.5587 per therm for residential customers, $0.5593 per therm for commercial/industrial high winter use customers, and $0.5580 per therm for commercial/industrial low winter use customers as shown on Proposed Third Revised Page 92 (Bates 211).

Q. Please explain tariff pages Proposed Third Revised Page 91 and Proposed Third Revised Page 92.

A. Proposed Third Revised Page 91 (Bates 210) and Proposed Third Revised Page 92 (Bates 211) contain the calculation of the 2022 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed Third Revised Page 92 (Bates 211), the 2022 Average Cost of Gas of $0.5587 per therm is derived by adding the Direct Cost of Gas Rate of $0.5539 per therm to the Indirect Cost of Gas Rate of $0.0048 per therm. The estimated total Anticipated Direct Cost of gas is $15,025,844 and the estimated Indirect Cost of Gas is $132,141. The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected Summer firm sales volumes of 27,125,444 therms. Proposed Third Revised Page 92 further shows that the Residential Cost of Gas Rate of $0.5587 per therm is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial High Winter Use Cost of Gas Rate of $0.5593 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.5580 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed Third Revised Page 91 (Bates 210). To derive the total Anticipated Direct Cost of Gas of $15,025,844, the Company starts with the Unadjusted Anticipated Cost of Gas of $10,330,821 and adds the Net Adjustment totaling $4,695,023.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1. Purchased Gas Demand Costs	$3,276,842
2. Purchased Gas Supply Costs	7,053,979
3. Produced Gas Costs	4,695,023
Total Unadjusted Anticipated Cost of Gas	$15,025,844

Q. What are the components of the adjustments to the cost of gas?

A. The adjustments to gas costs, listed on Proposed Third Revised Page 91 (Bates 210), are as follows:

1. Prior Period (Over)/Under Collection	$4,472,186
2. Interest	222,837
Total Adjustments	$4,695,023

Q. How does the proposed average Residential Summer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2021 Summer Period?

A. The cost of gas rate proposed in this filing is $0.2439 per therm higher than the initial rate approved by the Commission for the 2020 Summer Period ($0.3148 vs. $0.5587) (Schedule 8, Bates 233). This increase is due to a projected increase in supply costs and an under collection from the prior summer of $4,472,186.

Q. Does this conclude your testimony?

A. Yes, it does.

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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 21-XXX

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

DIRECT TESTIMONY

OF

DEBORAH M. GILBERTSON

September 1, 2021

Liberty™

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Q. Please state your name, position, and business address.

A. My name is Deborah M. Gilbertson. I am Senior Manager, Energy Procurement for Liberty Utilities Service Corp. ("LUSC"), which provides services to Liberty Utilities (EnergyNorth Natural Gas) Corp. ("Liberty" or "the Company"). My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please summarize your educational background and your business and professional experience.

A. I graduated from Bentley College in Waltham, Massachusetts, in 1996 with a Bachelor of Science in Management. In 1997, I was hired by Texas Ohio Gas where I was employed as a Transportation Analyst. In 1999, I joined Reliant Energy, located in Burlington, Massachusetts, as an Operations Analyst. From 2000 to 2003, I was employed by Smart Energy as a Sr. Energy Analyst. In 2004, I joined Keyspan Energy Trading as a Sr. Resource Management Analyst and from 2008 to 2011, I was employed by National Grid as a Lead Analyst in the Project Management Office. In 2011, I was hired by LUSC as a Natural Gas Scheduler and was promoted to Manager of Retail Choice in 2012. In 2016, I was promoted to Sr. Manager of Energy Procurement. In this capacity, I provide gas procurement services to Liberty.

Q. Have you previously testified in regulatory proceedings?

A. Yes, I have testified before the New Hampshire Public Utilities Commission ("Commission") on prior occasions.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to summarize the gas supply and firm transportation portfolio and the forecasted sendout requirements for Liberty for the 2021/22 peak and off-peak seasons. This information is provided in significantly more detail in the schedules that the Company is including with this filing.

Q. Please describe the firm transportation contract portfolio that the Company now holds.

A. The Company currently holds firm transportation contracts on Tennessee Gas Pipeline ("Tennessee") (106,833 MMBtu/day) and Portland Natural Gas Transmission System ("PNGTS") (1,000 MMBtu/day) to provide a daily deliverability of 107,833 MMBtu/day to its citygate stations. For this upcoming plan year, and subject to Commission approval for subsequent years, the Company has contracted for an additional 40,000 MMbtu/day of upstream Tennessee capacity which increases the Company's daily deliverability to 147,833 MMBtu/day. In addition to these citygate delivery contracts, the Company also holds other transportation contracts further upstream on other pipelines that feed into the citygate delivery transportation contracts. Schedule 12, page 1, in the Company's filing is a schematic diagram of the transportation contracts, and Schedule 12, page 2, is a table listing these contracts. The transportation contracts provide delivery of natural gas from three sources as described below.

First, the Company holds firm transportation contracts to allow for delivery of up to 13,122 MMBtu/day of Canadian supply. These consist of the following:

- The Company can receive up to 4,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held firm transportation contracts on Enbridge Inc. (formally Union Gas Limited), ("Enbridge"), TC Energy Corporation (formally TransCanada Pipelines Limited) ("TC Energy"), Iroquois Gas Transmission System ("Iroquois"), and Tennessee.
- The Company can receive up to 5,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held firm transportation contracts on Enbridge, TC Energy, PNGTS, and Tennessee.
- The Company can receive up to 3,122 MMBtu/day of firm Canadian supply from the Canadian/New York border at Niagara Falls, NY. This supply is delivered to the Company on Company-held firm transportation contracts on Tennessee.
- The Company can receive up to 1,000 MMBtu/day of firm Canadian supply from a Company-held firm transportation contract PNGTS for delivery to its Berlin service territory.

Second, the Company holds the following firm transportation contracts to allow for delivery of up to 106,596 MMBtu/day of domestic supply from the producing and market areas within the United States.

- The Company can receive up to 21,596 MMBtu/day of firm domestic supplies from Texas and Louisiana production areas. These supplies are delivered to the Company on firm transportation contracts on Tennessee.

- The Company can receive up to 85,000[1] MMBtu/day of firm supply from Tennessee's Dracut receipt point located in Dracut, Massachusetts. This supply is delivered to the Company on three firm transportation contracts on Tennessee.

Third, the Company holds the following firm transportation contracts to allow for delivery of up to 28,115 MMBtu/day of domestic supply from underground storage fields in the New York/Pennsylvania area or the purchase of flowing supply in or downstream of Tennessee Zones 4 and 5.

- The Company can receive up to 19,076 MMBtu/day of firm domestic supplies from its Tennessee FS-MA storage contract. This contract allows for a storage inventory capacity of 1,560,391 MMBtu. These supplies are delivered to the Company on firm transportation contracts on Tennessee.
- The Company can receive up to 9,039 MMBtu/day of firm domestic supplies from its storage contracts with National Fuel Gas Supply Corporation, Honeoye Storage Corporation, and Dominion Transmission, Inc. In aggregate, these contracts allow for a storage inventory capacity of 1,019,740 MMBtu. These supplies are delivered to the Company on a firm transportation contract on Tennessee.

1 An additional 5,000 MMBtu/day of Dracut capacity is used to transport the previously described 5,000 MMBtu/day of firm Canadian supply from Dawn, Ontario via Enbridge, TC Energy, and PNGTS.

Q. Have there been any changes in the portfolio of firm transportation contracts that the Company now holds since the Company submitted its Winter 2020/2021 Cost of Gas Filing?

A. Yes, the Company has contracted for 40,000 MMbtu/day of capacity from Tennessee's Dracut receipt point. This contract has been filed with the Commission for approval in Docket to DG 21-008. Further detail and rationale for the contract is currently under review in that docket.

Q. Would you describe the source of gas supplies used with the firm transportation contracts described previously?

A. The firm transportation contracts that interconnect at the Canadian border may source firm gas supplies from both Eastern and Western Canada. The Company's domestic long-haul firm transportation contracts source firm gas supplies primarily from the U.S. Gulf Coast during the winter period and provide access to natural gas supplies in the Marcellus Shale. Supplies purchased at the Dracut receipt point, on the other hand, may originate from any number of locations including Western and Eastern Canada and liquefied natural gas ("LNG") from the Canaport LNG import terminal in New Brunswick, Canada.

Q. Will there be any changes in the portfolio of supply contracts held by the Company as compared to the portfolio of contracts that existed when the Company submitted its Winter 2020/2021 Cost of Gas Filing?

A. Yes. Typically, the Company negotiates a number of different supply contracts for delivery during the peak period. Since its 2020/2021 COG filing, the Company has issued five requests for proposals ("RFP") for supply for the upcoming winter period. The first is for a baseload Tennessee Zone 6 citygate or Dracut supply; the second is for its Canadian firm transportation capacity interconnecting with Iroquois; the third is for its Tennessee long-haul capacity from the Gulf Coast and the Zone 4 market areas; the fourth is for a Tennessee Zone 6 citygate or Dracut swing supply with a call option; and the last is for a second Tennessee Zone 6 citygate or Dracut swing supply with a call option. Each of these five RFPs for the 2021/22 peak period supply are consistent with the RFPs issued for the 2020/21 peak period with the addition of the second call option to coincide with the incremental 40,000 MMbtu/day of capacity mentioned above.

Q. Could you describe the RFP process in more detail?

A. Yes. The Company issued an RFP for a baseload Tennessee Zone 6 citygate supply priced at NYMEX plus a fixed basis as a hedge against basis price spikes. This RFP was issued in accordance with the Company's revised hedging plan, which was approved by the Commission in Order No. 25,691 in Docket No. DG 14-133. The Company received proposals for a delivered citygate supply and has selected a winning bidder.

The Company also issued an RFP for supply originating from Dawn, Ontario. The Company entered into an Asset Management Agreement ("AMA") transaction that will provide a firm baseload supply during the peak period with index-based pricing. The Company has selected a winning bidder.

For the Tennessee long-haul firm transportation from the U.S. Gulf Coast, the Company issued an RFP for an AMA transaction coupled with a delivered service during the peak period. The Company has selected a winning bidder.

Lastly, the Company issued two RFPs for a Tennessee Zone 6 citygate or Dracut supply with an option for the Company to call on the supply as needed to meet day-to-day increases in demand. The RFPs requested a six-month Dracut or delivered citygate supply with swing nomination provisions whereby it intends to release its Dracut capacity to the winning bidder as needed. The price for this supply is market area index based. The Company has selected a winning bidder.

Q. Could you provide the status of the Company's storage refill plan?

A. Yes. During the 2021 off-peak period, the Company has been injecting supplies into its underground storage fields. The Company plans to have all storage fields, with the exception of its Tennessee FS-MA storage, full by November 1, 2021; the Tennessee FS-MA field is targeted to be approximately 95 percent full by November 1, 2021. The approximate five percent unfilled portion of FS-MA storage provides a buffer which allows the Company operational flexibility to inject some of its supply into storage if needed due to weather fluctuations during the month of November. By December 1, 2021, it is the Company's plan to have all of its storage fields full.

Q. Would you describe the additional sources of gas supply available to the Company that do not require pipeline transportation capacity?

A. The Company has three additional sources of gas supply available. First, as described in the 2020/21 COG filing, the Company contracted with Constellation LNG, LLC for a combination liquid/vapor service that can be used to either refill its LNG storage tanks during the peak period and/or deliver incremental supply to its citygate for up to 7,000 MMBtu per day in total. This flexibility will allow the Company to either call on citygate delivered supply or use the liquid option to refill its LNG inventory. Although this contract will continue through the upcoming peak period, it will expire on March 31, 2022. In addition to the combination liquid/vapor service, the Company has contracted for dedicated LNG trucking in order to refill its LNG storage inventory. Since the Company's LNG storage capability is limited, having dedicated LNG trucks allows the Company to replenish inventory as it is used, provides supply security for its customers, and enables the Company to adhere to its seven-day storage inventory requirement established by Puc 506.03.

Second, the Company refilled its propane inventory including approximately 390,000 gallons of inventory at its Amherst storage facility.

Third, the Company has solicited bids for an LNG supply contract to be used as winter liquid refill only. This incremental liquid refill contract must also provide trucking of the

LNG for storage refill. By using the Constellation LNG vapor option along with a separate refill supply contract, the Company will be positioned to meet the demands of the seven-day storage inventory requirement. The Company has selected the winning bidders.

Q. Please describe the supplemental gas supply facilities available to the Company.

A. The Company owns three LNG vaporization facilities in Concord, Manchester, and Tilton that have a combined design vaporization rate of approximately 22,800 MMBtu/day, but are limited operationally by the combined workable storage capacity of approximately 12,600 MMBtu. As described previously, the Company solicited bids for additional LNG refill and associated trucking in order to utilize more vaporization capacity from its LNG facilities. The Company's LNG facilities will be refilled with liquid natural gas from the previously mentioned Constellation combination liquid/vapor service and/or the incremental LNG refill supply.

Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua, and Tilton that have historically been designated a combined design vaporization capacity of approximately 34,600 MMBtu/day and a combined workable storage capacity of approximately 122,590 MMBtu. (For more information on the propane facilities, please refer to Attachment DMG-1, which is a copy of the Company's response to CLF 1-20 in Docket No. DG 21-008 which discusses a propane study being performed by the Company to analyze and update the actual operational vaporization capacity of these facilities.)

The Company has allocated approximately 12,000 MMBtu of the Amherst propane storage capacity to its Keene Division, leaving approximately 110,700 MMBtu of combined workable storage capacity for Liberty. The Company's propane facilities were refilled during the summer of 2021 and they are ready for the 2021/22 peak period. The Company will seek to have arrangements in place for its propane trucking needs for the upcoming peak period.

Together, these LNG and propane facilities provide the Company and its customers with necessary system pressure support during peak days as well as a critical gas supply source to meet design day requirements. These facilities contribute to the Company's reliable, flexible, and least-cost resource portfolio.

Q. Ms. Gilbertson, what was the source of the projected sendout requirements and costs used in this filing?

A. As in prior cost of gas filings, the Company used projected sendout requirements and costs from its internal budgets and forecasts.

Q. Would you please describe the forecasted sendout requirements for the peak period of 2021/22?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers at 94,216,591 therms over the period November 1, 2021, to April 30, 2022, under normal weather conditions, which is up from last year's forecasted volume of 90,922,460 therms for the period November 1, 2020, to April 30, 2021. In comparison, the normalized actual sendout for firm sales customers for the

November 1, 2020, to April 30, 2021, period was 93,155,745 therms (Reconciliation Filing, Summary Page 5, 'Total Volume Weather Variance,' Column B).

Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 104,530,752 therms over the period November 1, 2021, to April 30, 2022, under design weather conditions, which is up from last year's forecasted volume of 101,061,871 therms for the period November 1, 2020, to April 30, 2021. For the current peak period forecast, design weather requirements are approximately 10 percent greater than normal sendout requirements for weather that is 10 percent colder than normal.

In Schedule 11C, the Company summarizes the normal and design year sendout requirements, the seasonally available contract quantities (inclusive of assigned and Company Managed capacity), and the utilization rates of its pipeline firm transportation and storage contracts.

Schedule 11D shows the Company's forecasted design day sendout for sales customers for the upcoming 2021/22 winter period of 1,283,926 therms, which is up from last year's figure of 1,248,088 therms.

Q. Would you please describe the forecasted sendout requirements for the off-peak period of 2022?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements of 22,950,820 therms over the period May 1 to October 31, 2022, under normal weather conditions, which is slightly higher than last year's forecasted volume of 22,065,798 therms over the period May 1 to October 31, 2021.

Schedule 11B shows the Company's forecasted sendout requirements of 22,928,033 therms over the period May 1 to October 31, 2022, under design weather conditions, which is higher than last year's forecasted volume of 22,175,995 therms over the period May 1 to October 31, 2021.

In Schedule 11C, the Company summarizes the normal and design off-peak sendout requirements, the seasonally available contract quantities (inclusive of assigned and Company Managed capacity), and the calculated utilization rates of its pipeline transportation and storage contracts based on the normal and design off-peak forecasts contained in Schedules 11A and 11B.

Q. Why did the Company contract for an additional 40,000 of Tennessee capacity?

A. Over the past several years the need for additional gas resources to meet the ever-increasing demand of Liberty's customers has continued to grow. The Company has presented various demand forecasts, resource requirement analyses, and waiver requests in many dockets over the years. This began with the request for approval of a Precedent Agreement ("PA") for 115,000 MMbtu/day of capacity on the proposed Northeast Energy Direct ("NED") project in 2014 which was to provide additional capacity to Liberty. The Company contracted for capacity on the NED Project to meet its projected demand growth, and the Commission approved the PA. *See* Order No. 25,822 (Oct. 2, 2015). However, Tennessee ultimately cancelled NED.

Since the cancellation of the NED project in 2016, the Company has conducted a rigorous search and analysis of capacity options to increase the deliverability of firm gas supplies and/or decrease the requirement of Puc 506.03, the On-Site Storage Requirement rules. As described above, beginning on November 1, 2017, the Company entered into an agreement with Engie/Constellation to supply 7,000 MMbtu/day of either firm vapor to the citygate or liquid natural gas to refill the Company's existing LNG facilities. That contract will expire on March 31, 2022. Although that additional capacity/supply was a much-needed supplement to the portfolio, from December 27, 2017 through January 2, 2018, the Company's service territory experienced a significant cold weather event which surpassed its historical consecutive seven-day cold snap. As a result, the Company needed to have more supplemental gas on hand to meet the increased demand attributable to the higher 7-day forecast as stipulated in Puc.506.03. In August 2019, the Company filed with the Commission a request to waive and modify the requirements of Puc 506.03. At that time, the Company knew it did not have (nor could have had) enough supplemental supply on hand for the upcoming peak season to meet the demands of the rule as written. The Commission approved the Company's request for a waiver and modifications of Puc 506.03 for three years. *See* January 5, 2018, secretarial letter in Docket No. DG 17-200. That waiver will expire in March of 2022.

With the expirations of both the Engie/Constellation agreement and the waiver of Puc 506.03, the Company is again faced with imminent concerns for capacity and supply shortfall. If approved, the contract for 40,000 MMbtu/day of incremental capacity with Tennessee will ensure that the Company will have sufficient resources on hand to meet near term design day requirements of its customers. (As mentioned above, please refer to Docket No. DG 21-008 for additional detail.)

Q. Will the Company need the entire 40,000 MMbtu/day in the first year?

A. No, the Company will release any excess capacity in the market consistent with its current cost mitigation strategy designed to reduce costs to customers.

Q. Can you comment on what is causing the dramatic increase in forward looking natural gas prices as compared to 2020/2021 peak period?

A. As with all local distribution companies across the United States, and the Northeast in particular, the Company's purchase prices for its natural gas supplies are impacted by regional, national, and global forces. According to the most recent data, NYMEX natural gas futures continue to trade at their highest summer levels in seven years. Compared to last year, for example, NYMEX on average is currently trading at approximately 30% higher than this time last year. This is largely related to fears regarding national storage levels for the coming winter. Hot summer temperatures across the nation have stymied consistent, larger injections relative to the five-year average, with last year being particularly impacted. Additionally, demand for U.S. LNG exports to international markets are robust, which reduces supply availability to U.S. markets. The consensus is that until storage across the country returns to normal levels and LNG exports level off, the higher domestic prices are likely to persist.

Q. Please provide the results of the Company's basis hedging program for the winter of 2020/21.

A. For the winter of 2020/21 the Company hedged the Tennessee Zone 6 basis through the purchase of physical supply for its baseload requirements from Dracut for the months of

December, January, and February as provided for in Docket No. DG 14-133 and approved in Order *Nisi* No. 25,691. The result of this basis hedging program showed a cost of approximately $1,500,000. Although the Company cannot predict whether the hedge program will result in a gain or loss each year, it does support the need for price stabilization against fluctuations in the market prices during peak period.

Q. Has the Company hedged the Tennessee Zone 6 basis for the winter 2021/22?

A. Yes, the Company conducted an RFP to solicit physical supply basis bids for the months of December, January, and February during the 2021/22 winter and has selected a supplier.

Q. Does this conclude your direct pre-filed testimony in this proceeding?

A. Yes, it does.

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

DG 21-008
Petition for Approval of a Firm Transportation Agreement with
Tennessee Gas Pipeline Company, LLC

Conservation Law Foundation Data Requests - Set 1

Date Request Received: 4/9/21 Date of Response: 4/23/21
Request No. CLF 1-20 Respondent: William R. Killeen

REQUEST:

Has the Company analyzed the costs and historic record of having propane facilities performing at their design or nameplate vaporization rates? Is there a record of them not performing as designed to help meet peak demands? Are there upgrades and investments in these facilities that can be made to help them perform to design and nameplate ratings? Have such upgrades been considered as options to help meet peak day demands? Please provide any workpapers and analyses with formulas intact.

RESPONSE:

The Company's three propane production facilities directly connected to its distribution system are located in Manchester, Nashua, and Tilton. In total, they have a design, or nameplate, vaporization capacity of approximately 34,600 MMBtu/day and a combined workable storage capacity of approximately 122,590 MMBtu. Historically, the facilities have never reached their nameplate vaporization capacity primarily due to the fact that there is not sufficient natural gas flowing by these propane facilities to provide a proper blending of a propane/air mix with natural gas. The historical peak sendout from the Nashua propane plant was 9,954 Dth which occurred on February 14, 2016. The historical peak sendout from the Manchester propane plant was 9,921 Dth which occurred on February 5, 2007. The historical peak sendout for the Tilton propane plant was 1,242 Dth (the Company does not have the date on which this occurred). While the combined total historical peak vaporization capacity of these facilities was 21,117 Dth, the peak vaporization capacity for each facility occurred on different days. The combined single day peak vaporization from these facilities was 18,869 Dth which occurred on February 5, 2007.

As to whether any upgrades or investments can be made to these propane facilities, the Company recently engaged with a process control engineer to analyze the current operating controls at Manchester and Nashua to see if upgrades would allow for increased vaporization capacity. The process control engineer will take into consideration the adverse impact that propane/air injection has on high efficiency equipment. As noted in prior dockets, the Company is very concerned with customer outages and complaints associated with propane production. Due to the low tolerance of high efficiency equipment to handle the particular characteristics of propane air, customer outages and complaints have been correlated directly to when the Company is utilizing its propane facilities. As recently as March 15, 2021, the Company received significant customer complaints when it had to utilize its propane facility in Manchester to meet increased demand due to much colder than forecast temperatures.

Given the increased installation of high efficiency equipment and the adverse impact that propane/air blending has on that equipment, it is highly unlikely that the operational capacity of the Company's existing propane facilities will reach, or exceed, historical levels. Rather, it is more likely that the operational capacity of the propane facilities will decrease over time as new high efficiency equipment is added by customers.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 21-XXX

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

DIRECT TESTIMONY

OF

MARY E. CASEY

September 1, 2021

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I. INTRODUCTION

Q. Please state your name, job title, and job description.

A. My name is Mary E. Casey. I am the Senior Manager, Environment, for Liberty Utilities Service Corp. ("LUSC"). I am responsible for overseeing the management, investigation, and remediation of manufactured gas plant (MGP) sites for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty" or "the "Company"), as well as operational environmental compliance, including air and waste permitting, wetlands permitting, and protection and spill response.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science in Chemical Engineering from Polytechnic Institute of New York, and a Master of Science in Civil/Environmental Engineering from Polytechnic University. I have been employed by LUSC since July 3, 2012, managing the investigation and remediation of Liberty's MGP sites. Prior to my employment by LUSC, I held the position of Principal Environmental Engineer for National Grid and KeySpan Energy, with responsibility for operational environmental compliance.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the status of Liberty's site investigation and remediation efforts at various MGP sites in New Hampshire, to briefly describe the MGP-related activities performed by the various contractors and consultants, to discuss the costs for which the Company is seeking rate recovery, and to describe the status of the Company's efforts to seek reimbursement for MGP-related liabilities from third parties. My testimony is intended to update the information provided by the Company in prior cost of gas proceedings. The costs associated with these investigations and remediation efforts and certain of the amounts recovered from third parties are included in the schedules and other data prepared by Mr. Simek and Ms. McNamara as part of the Local Distribution Adjustment Charge ("LDAC") portion of the Company's cost of gas filing.

II. STATUS OF INVESTIGATION AND REMEDIATION ACTIVITIES

Q. Please briefly describe the status of each of the Company's MGP sites.

A. Consistent with past practice, the description of the status of investigation and remediation efforts at each site, as well as the various efforts to recover the site investigation and remediation costs from third parties, are summarized in materials included in the Company's filing at Schedule 20.

Q. Please briefly describe the current status of the Company's remediation efforts at the Lower Liberty Hill site in Gilford and any significant events over the course of the past year at that site.

A. The project has been completed since December 2015. The site is stable, and the grass is mowed twice a year. The Notice of Activity and Use Restriction (AUR) was approved by New Hampshire Department of Environmental Services ("NHDES") and recorded at the Belknap Registry of Deeds in February 2017. The groundwater wells are monitored and sampled once a year per the Groundwater Management Permit that was obtained from NHDES in May 2017.

Q. Please briefly describe the current status of the Company's remediation work at the Manchester MGP.

A. On-site activities in the past year were minimal due to COVID-19 access limitations. Some costs were incurred relative to handling MGP-impacted media that resulted from the repair of a sink hole in within the LNG tank area. Groundwater monitoring is ongoing twice a year pursuant to the Groundwater Management Permit for this site.

Q. Please briefly describe the current status of the Company's remediation work at the Concord MGP.

A. The Company continues to move toward a remedy for the MGP-impacted "Concord Pond" site on the parcel known as Healy Park. In 2020, the City and the Company finalized an access agreement that gives Liberty access for the pre-design investigation field work, the construction of the remedy, and subsequent maintenance of the capped area after its completion. Pre-design field investigations commenced in 2021 to develop the final design of a wetland and subaqueous cap, per the Remedial Action Plan approved by NHDES. The construction of the remedy is planned to take place in late summer 2022.

In 2017, the Company received approval from NHDES on a near-bank sediment sampling program in the Merrimack River, or Monitored Natural Recovery (MNR). This program involves annual sediment sampling for contaminants and river bathymetry studies to monitor both the chemical and physical behavior of sediments that may have been impacted by coal tar wastes. There will be five annual samplings, the fourth of which was conducted in October 2020.

As for the Gas Holder site, the City and the Company jointly prepared a report in 2019 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 testimony, 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. Liberty is not prepared to seek recovery of the costs contributed to the stabilization of the holder house at this time because the work has not yet been performed and will likely not be complete by the time of a hearing in this docket. Liberty expects that it will seek recovery of those costs in next year's cost of gas/LDAC filing. Liberty will provide an update of this project at hearing.

Q. Please briefly describe the current status of the Company's remediation work at the Nashua MGP site.

A. In May 2019, the NHDES accepted details of a cap design for the central portion of the property, and construction was planned for 2020, in conjunction with a capital paving project for this property. However, this cap and pave project has been moved to the 2021 construction season due to the COVID-19 pandemic. The Company is presently working on obtaining State and Local permitting for this project, and construction is targeted for late summer 2021.

Q. What other MGP investigation and remediation activity has the Company undertaken in the last year?

A. No other MGP investigation and remediation activity has occurred in the last year.

III. STATUS OF INSURANCE COVERAGE LITIGATION

Q. Have there been any recent significant developments in the Company's efforts to seek contribution from its insurance carriers in the past year?

A. No. Insurance recovery efforts are complete with respect to all the Company's former MGP sites.

Q. What environmental remediation efforts do you anticipate for the remainder of 2021 and in 2022?

A. At the Manchester MGP site, the Company will continue remediation of localized areas of contamination on-site as well as working on the storm drain improvement for a deteriorated drainage pipe along the western boundary of the property. At the Concord MGP site, as described above, Liberty is working with other parties to stabilize the gas holder house to preserve its function as a cap over its footprint; Liberty will continue environmental site monitoring. For the Concord Pond site, the Company will continue to develop the final design of a wetland and subaqueous cap, with the construction of the remedy expected to occur in late summer 2022. The monitoring of near bank sediments will continue in October 2021 per the NHDES-approved Monitored Natural Recovery plan. At the Nashua MGP site, the Company is targeting later in 2021 for capping and paving to commence, now that approval of the cap design has been received. All sites are also now in the monitoring phase, so groundwater monitoring will occur at all of them under their respective Groundwater Management Permits.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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II RATE SCHEDULES
FIRM RATE SCHEDULES

	~~Rates effective November 1, 2020 - April 30, 2021~~ Rates effective November 1, 2021 - April 30, 2022 Winter Period				~~Rates Effective May 1, 2021 - October 31, 2021~~ Rates Effective May 1, 2022 - October 31, 2022 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
Residential Non Heating - R-1	~~$ 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~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.0020~~	~~$ 0.3860~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.7597~~
Residential Heating - R-3	~~$ 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				all therms			
All Therms	$ 0.5632	$ 1.1339	$ 0.1444	$ 1.8415	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.5678~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.1838~~	~~$ 0.5678~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.9415~~
Residential Heating - R-4	~~$ 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				all therms			
All Therms	$ 0.3098	$ 0.6236	$ 0.1444	$ 1.0778	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.3123~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.6776~~	~~$ 0.5678~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.9415~~
Commercial/Industrial - G-41	~~$ 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				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~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.8375~~
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~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.6829~~
Commercial/Industrial - G-42	~~$ 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~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7948~~
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~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.6519~~
Commercial/Industrial - G-43	~~$ 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~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.4868~~
Commercial/Industrial - G-51	~~$ 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~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6593~~
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~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.5600~~
Commercial/Industrial - G-52	~~$ 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~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.5521~~
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~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4758~~
Commercial/Industrial - G-53	~~$ 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~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4572~~
Commercial/Industrial - G-54	~~$ 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~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.6865~~	~~$ 0.0353~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4107~~

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~~

II RATE SCHEDULES
FIRM RATE SCHEDULES

	~~Rates effective November 1, 2020 - April 30, 2021~~ Rates effective November 1, 2021 - April 30, 2022 Winter Period				~~Rates Effective May 1, 2021 - October 31, 2021~~ Rates Effective May 1, 2022 - October 31, 2022 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**
Residential Non Heating - R-5	~~$ 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~~
Residential Heating - R-6	~~$ 20.15~~			~~$ 20.15~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 20.01			$ 20.01	$ 20.01			$ 20.01
Size of the first block	All Therms		~~$~~					
Therms in the first block per month at	$ 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~~	~~$ 1.1118~~
Residential Heating - R-7	~~$ 11.08~~			~~$ 11.08~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 11.01			$ 11.01	$ 20.01			$ 20.01
Size of the first block	All Therms		~~$~~					
Therms in the first block per month at	$ 0.4027	$ 0.6236	$ 0.1444	$ 1.1708	$ 0.7322	$ 0.5587	$ 0.1444	$ 1.4353
	~~$ 0.4060~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.7713~~	~~$ 0.7381~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 1.1118~~
Commercial/Industrial - G-44	~~$ 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	$ 0.6094	$ 0.5593	$ 0.0878	$ 1.2565
	~~$ 0.6126~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.2233~~	~~$ 0.6126~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.9790~~
All therms over the first block per month at	$ 0.4094	$ 1.1341	$ 0.0878	$ 1.6313	$ 0.4094	$ 0.5593	$ 0.0878	$ 1.0565
	~~$ 0.4114~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0221~~	~~$ 0.4114~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7778~~
Commercial/Industrial - G-45	~~$ 224.11~~			~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
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 at	$ 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~~
			~~$~~					
Commercial/Industrial - G-46	~~$ 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 at	$ 0.3406	$ 1.1341	$ 0.0878	$ 1.5625	$ 0.1557	$ 0.5593	$ 0.0878	$ 0.8028
	~~$ 0.3423~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9530~~	~~$ 0.1565~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.5229~~
Commercial/Industrial - G-55	~~$ 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 at	$ 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~~
Commercial/Industrial - G-56	~~$ 224.11~~		~~$~~	~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
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	$ 0.3156	$ 1.1324	$ 0.0878	$ 1.5358	$ 0.2287	$ 0.5580	$ 0.0878	$ 0.8745
	~~$ 0.3171~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9386~~	~~$ 0.2297~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6051~~
All therms over the first block per month at	$ 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~~	~~$ 0.5058~~
			~~$~~					
Commercial/Industrial - G-57	~~$ 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 at	$ 0.2207	$ 1.1324	$ 0.0878	$ 1.4409	$ 0.1059	$ 0.5580	$ 0.0878	$ 0.7517
	~~$ 0.2216~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8431~~	~~$ 0.1063~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4817~~
Commercial/Industrial - G-58	~~$ 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 at	$ 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~~

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Issued by: ______________________
Neil Proudman
Title: President

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

II. RATE SCHEDULES
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021~~
(Refer to Text in Section 17(A) Fixed Price Option Program)

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 47,150,454~~		$ 74,822,730		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Direct Cost of Gas Rate		~~$ 0.5345~~		$ 0.8557	per therm
Demand Cost of Gas Rate	~~$ 12,978,688~~	~~$ 0.1471~~	$ 13,859,546	$ 0.1585	
Commodity Cost of Gas Rate	~~33,157,366~~	~~$ 0.3759~~	$ 60,820,831	$ 0.6955	
Adjustment Cost of Gas Rate	~~1,014,399~~	~~$ 0.0115~~	$ 142,353	$ 0.0016	
Total Direct Cost of Gas Rate	~~$ 47,150,454~~	~~$ 0.5345~~	$ 74,822,730	$ 0.8557	
Total Anticipated Indirect Cost of Gas	~~$ 2,222,909~~		$ 4,360,293		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Indirect Cost of Gas		~~$ 0.0252~~		$ 0.0499	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		~~$ 0.5597~~		**$ 0.9056**	
Calculation of FPO					
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		~~$ 0.5597~~		**$ 0.9056**	
FPO Risk Premium		~~$ 0.0200~~		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE ~~(11/01/20)~~ (11/01/21)		~~$ 0.5797~~		**$ 0.9256**	
RESIDENTIAL COST OF GAS RATE - EXCLUDING GAP - ~~(11/01/2020)~~ (11/1/2021)	**/therm**	~~$ 0.5797~~	**/therm**	**$ 0.9256**	

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 47,150,454~~		$ 74,822,730		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Direct Cost of Gas Rate		~~$ 0.5345~~		$ 0.8557	per therm
Demand Cost of Gas Rate	~~$ 12,978,688~~	~~$ 0.1471~~	$ 13,859,546	$ 0.1585	
Commodity Cost of Gas Rate	~~33,157,366~~	~~$ 0.3759~~	$ 60,820,831	$ 0.6955	
Adjustment Cost of Gas Rate	~~1,014,399~~	~~$ 0.0115~~	$ 142,353	$ 0.0016	
Total Direct Cost of Gas Rate	~~47,150,454~~	~~$ 0.5345~~	$ 74,822,730	$ 0.8557	
Total Anticipated Indirect Cost of Gas	~~$ 2,222,909~~		$ 4,360,293		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Indirect Cost of Gas		~~$ 0.0252~~		$ 0.0499	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		~~$ 0.5597~~		**$ 0.9056**	
Calculation of FPO					
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		~~$ 0.3078~~		**$ 0.4981**	
FPO Risk Premium		$ 0.0110		$ 0.0110	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE ~~(11/01/20)~~ (11/01/21)		~~$ 0.3188~~		**$ 0.5091**	
RESIDENTIAL COST OF GAS RATE - GAP - ~~(11/01/2020)~~ (11/1/2021)	**/therm**	~~$ 0.3188~~	**/therm**	**$ 0.5091**	

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Effective:	~~November 1, 2020~~	November 1, 2021	Title:	President

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NHPUC NO. 11 - GAS **Proposed Second Revised Page 95**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 95**

CALCULATION OF FIRM SALES COST OF GAS RATE

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 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	~~$ 47,150,454~~		$ 94,810,891		
Projected Prorated Sales (11/01/20 - 04/30/21)~~(11/01/19 - 04/30/20)~~	~~88,213,529~~		$ 87,443,741		
Direct Cost of Gas Rate		~~0.5345~~		$ 1.0843	per therm
Demand Cost of Gas Rate	~~$ 12,978,688~~	~~0.1471~~	$ 13,868,897	$ 0.1586	
Commodity Cost of Gas Rate	~~33,157,366~~	~~0.3759~~	$ 80,780,853	$ 0.9238	
Adjustment Cost of Gas Rate	~~1,014,399~~	~~0.0115~~	$ 161,141	$ 0.0018	
Total Direct Cost of Gas Rate	~~$ 47,150,454~~	~~0.5345~~	$ 94,810,891	$ 1.0843	
Total Anticipated Indirect Cost of Gas	~~$ 2,222,909~~		$ 4,338,002		
Projected Prorated Sales (11/01/20 - 04/30/21)~~(11/01/19 - 04/30/20)~~	~~88,213,529~~		87,443,741		
Indirect Cost of Gas		~~$ 0.0252~~		$ 0.0496	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/21				$ 1.1339	per Therm
~~TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/19~~		~~$ 0.5597~~			

RESIDENTIAL COST OF GAS RATE - 11/01/21	**COGwr**	**$ 1.1339**	**/therm**	
~~RESIDENTIAL COST OF GAS RATE - 11/01/20~~	**~~COGwr~~**	**~~$ 0.5597~~**	**~~/therm~~**	
Maximum	(COG + 25%)	~~$ 0.7754~~	$ 1.4174	
GAS ASSISTANCE PLAN RESIDENTIAL COST OF GAS RATE R-4 & R-7 - 11/01/21		**$ 0.6236**	**/therm**	
~~GAS ASSISTANCE PLAN RESIDENTIAL COST OF GAS RATE R-4 & R-7 - 11/01/20~~		**~~$ 0.3078~~**	**~~/therm~~**	
Maximum	(COG + 25%)	~~$ 0.3848~~	$ 0.7796	
C&I LOW WINTER USE COST OF GAS RATE - 11/01/21	**COGwl**	**$ 1.1324**	**/therm**	
~~C&I LOW WINTER USE COST OF GAS RATE - 11/01/20~~	**~~COGwl~~**	**~~$ 0.5686~~**	**~~/therm~~**	

Average Demand Cost of Gas Rate Effective ~~11/01/20~~ 11/01/21	~~$ 0.1471~~	$ 0.1586	Maximum	(COG + 25%)	~~$ 0.7107~~	$ 1.4155
Times: Low Winter Use Ratio (Winter)	~~1.0620~~	0.9910				
Times: Correction Factor	~~0.9984~~	1.0001				
Adjusted Demand Cost of Gas Rate	~~$ 0.1560~~	$ 0.1572				
Commodity Cost of Gas Rate	~~$ 0.3759~~	$ 0.9238				
Adjustment Cost of Gas Rate	~~0.0115~~	0.0018				
Indirect Cost of Gas Rate	~~0.0252~~	0.0496				
Adjusted C&I Low Winter Use Cost of Gas Rate	~~$ 0.5686~~	$ 1.1324				

C&I HIGH WINTER USE COST OF GAS RATE - 11/01/21	**COGwh**	**$ 1.1341**	**/therm**
~~C&I HIGH WINTER USE COST OF GAS RATE - 11/01/20~~	**~~COGwh~~**	**~~$ 0.6190~~**	**~~/therm~~**

Average Demand Cost of Gas Rate Effective ~~11/01/20~~ 11/01/21	~~$ 0.1471~~	$ 0.1586	Maximum	(COG + 25%)	~~$ 0.6973~~	$ 1.4176
Times: High Winter Use Ratio (Winter)	~~0.9890~~	1.0017				
Times: Correction Factor	~~0.9984~~	1.0001				
Adjusted Demand Cost of Gas Rate	~~$ 0.1452~~	$ 0.1589				
Commodity Cost of Gas Rate	~~$ 0.3759~~	$ 0.9238	Minimum			
Adjustment Cost of Gas Rate	~~0.0115~~	0.0018	Maximum			
Indirect Cost of Gas Rate	~~0.0252~~	0.0496				
Adjusted C&I High Winter Use Cost of Gas Rate	~~$ 0.5578~~	$ 1.1341				

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Anticipated Cost of Gas
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~**PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021**~~
(REFER TO TEXT ON IN SECTION 17 COST OF GAS CLAUSE)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 12,022,922~~		$ 12,887,000	
Supply Costs:	~~28,279,842~~		72,351,034	
Storage Gas:				
Demand, Capacity:	~~$ 955,766~~		$ 981,898	
Commodity Costs:	~~3,285,987~~		6,130,435	
Produced Gas:	~~1,591,538~~		2,299,384	
Hedged Contract (Saving)/Loss	~~-~~		-	
Hedge Underground Storage Contract (Saving)/Loss	~~-~~		-	
Unadjusted Anticipated Cost of Gas		~~$ 46,136,054~~		$ 94,649,751
Adjustments:				
Prior Period (Over)/Under Recovery (as of 05/01/21)	~~$ 2,227,421~~		$ 1,431,639	
Interest	~~74,791~~		44,085	
Fuel Inventory Revenue Requirement	~~441,037~~		335,667	
Broker Revenues	~~(32,725)~~		(3,600)	
Refunds from Suppliers	~~-~~		-	
Fuel Financing	~~-~~		-	
Transportation CGA Revenues	~~(4,543)~~		(6,938)	
Interruptible Sales Margin	~~-~~		-	
Capacity Release and Off System Sales Margins	~~(1,736,581)~~		(1,676,512)	
Hedging Costs	~~-~~		-	
Fixed Price Option Administrative Costs	~~45,000~~		36,800	
Total Adjustments		~~1,014,399~~		161,141
Total Anticipated Direct Cost of Gas		~~$ 47,150,454~~		$ 94,810,891
Anticipated Indirect Cost of Gas				
Working Capital:				
Total Unadjusted Anticipated Cost of Gas 11/01/21 - 04/30/22	~~$ 46,136,054~~		$ 94,649,751	
Working Capital Rate: Lead Lag Days / 365	~~0.0391~~		0.0705	
Prime Rate	~~3.25%~~		3.25%	
Working Capital Percentage	~~0.127%~~		0.229%	
Working Capital	~~$ 58,634~~		$ 216,761	
Plus: Working Capital Reconciliation (Acct 142.20)	~~(66,837)~~		(14,859)	
Total Working Capital Allowance	-	~~(8,203)~~		201,902
Bad Debt:				
Total Unadjusted Anticipated Cost of Gas 11/01/21 - 04/30/22	~~$ 46,136,054~~		$ 94,649,751	
Less: Refunds	~~-~~		-	
Plus: Total Working Capital	~~(8,203)~~		201,902	
Plus: Prior Period (Over)/Under Recovery	~~2,227,421~~		1,431,639	
Subtotal	~~$ 48,355,272~~		$ 96,283,291	
Bad Debt Percentage	~~1.11%~~		0.70%	
Bad Debt Allowance	~~$ 536,744~~		$ 673,983	
Plus: Bad Debt Reconciliation (Acct 175.52)	~~(296,628)~~		(223,340)	
Total Bad Debt Allowance	-	~~$ 240,116~~		$ 450,643
Production and Storage Capacity		~~$ 1,980,428~~		$ 3,685,458
Miscellaneous Overhead 11/01/21 - 04/30/22	~~$ 13,170~~		$ -	
Times Winter Sales	~~89,365~~		91,677	
Divided by Total Sales	~~111,369~~		115,043	
Miscellaneous Overhead		~~10,568~~		-
Total Anticipated Indirect Cost of Gas		~~$ 2,222,909~~		$ 4,338,002
Total Cost of Gas		~~$ 49,373,363~~		$ 99,148,894

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II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021~~
(Refer to text in Section16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	~~(Col 4)~~	(Col 2)	(Col 3)	(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:						
PROPANE	~~$ 568,511~~			$ 920,459		
LNG	~~$ 1,023,026~~			1,378,925		
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	~~1,591,538~~			2,299,384		
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	~~8.7%~~			8.7%		
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	~~$ 138,464~~			$ 200,046		
PROJECTED FIRM THROUGHPUT (THERMS):						
FIRM SALES	~~89,364,968~~	~~67.8%~~		91,676,680	68.3%	
FIRM TRANSPORTATION SUBJECT TO FTCG	~~42,456,275~~	~~32.2%~~		42,583,790	31.7%	
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	~~131,821,243~~	~~100.0%~~		134,260,470	100.0%	
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	~~32.2%~~	~~x 138,464 =~~	~~$ 44,596~~	31.7% x	$ 200,046 =	$ 63,449
PRIOR (OVER) OR UNDER COLLECTION			(40,053)			(56,511)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS			~~$ 4,543~~			$ 6,938
PROJECTED FIRM TRANSPORTATION THROUGHPUT			~~42,456,275~~			42,583,790
FIRM TRANSPORTATION COST OF GAS			~~$ 0.0001~~			$ 0.0002

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Title: President

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NHPUC NO. 11 - GAS **Proposed Second Revised Page 99**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 99**

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required Annual Environmental Increase	~~$ 2,864,179~~	$ 2,351,805	
Second one-third of prior period under recoveries (through June 2019)	~~$ 341,389~~	$ 341,389	
July 2020 - June 2021 recovery difference between actual and estimate	~~$ 338,564~~	$ 139,028	
Environmental Subtotal	~~$ 3,544,132~~	$ 2,832,222	
Overall Annual Net Increase to Rates			
Estimated weather normalized firm therms billed for the twelve months ended 10/31/2022 - sales and transportation	~~179,574,679~~	182,829,872	therms
Surcharge per therm	~~$ 0.0197~~	$0.0155	per therm
Total Environmental Surcharge	~~$ 0.0197~~	$0.0155	

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty
Local Distribution Adjustment Charge (LDAC) decrease due to Rate Case Expense and Recoupment
For LDAC effective November 1, 2021 - October 31, 2022
~~For LDAC effective November 1, 2020 - October 31, 2021~~

~~1~~	~~Rate Case Expense Remaining from Docket No. DG 17-048~~	~~$87,069~~
~~2~~	~~Recoupment Remaining from Docket No. DG 17-048~~	~~$0~~
~~3~~	~~July 1, 2020 Balance~~	~~$87,069~~
~~4~~	~~Plus Estimated Interest from July 2020 through October 2020~~	~~$745~~
~~5~~	~~Minus Estimated Recoveries from July 2020 through October 2020~~	~~($43,733)~~
~~6~~	~~Total Estimated Remaining Recovery As of November 1, 2020~~	~~$44,081~~
~~7~~	~~Estimated November 2019 - October 2020 Interest~~	~~$538~~
~~8~~	~~Total Remaining Recovery~~	~~$44,619~~
~~9~~	~~Estimated November 2020 - October 2021 Sales (therms)~~	~~179,574,679~~
~~10~~	~~RCE & Recoupment rate per therm November 2020 - October 2021~~	~~$0.0002~~

1	Rate Case Exepense	
2	Prior Period Balance	($11,949)
3	Expenses thru June 30, 2021	$785,177
4	Balance at June 30, 2021	$773,228
5	Less: Accrual Balance	($26,000)
6	Adjusted Rate Case Expense	$747,228
7		
8	Recoupment	
9	Distribution Recoupment from Docket No. DG 20-105	($568,780)
10	Indirect Costs Recoupment from Docket No. DG 20-105	$1,900,000
11	Total Recoupment	$1,331,220
12		
13	July 1, 2021 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	($7,864)
20		
21	Total Estimated Remaining Recovery As of November 1, 2021	$2,187,779
22		
23	Estimated November 2021 - October 2022 Interest	$26,727
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

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

Issued by: ______________ Neil Proudman
Title: President

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

NHPUC NO. 11 - GAS **Proposed Second Revised Page 101**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 101**

Local Delivery Adjustment Clause Calculation

				Sales Customers		Transportation Customers		
Residential Non Heating Rates - R-1								
Energy Efficiency Charge	~~$ 0.0831~~		$ 0.0861					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0831~~		$ 0.0861				
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155				
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0562)~~		$ 0.0152				
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -				
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121				
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156				
LDAC		~~**$ 0.0589**~~		**$ 0.1444**				**per therm**

Residential Heating Rates - R-3, R-4, R-6, R-7								
Energy Efficiency Charge	~~$ 0.0831~~		$ 0.0861					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0831~~		$ 0.0861				
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155				
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0562)~~		$ 0.0152				
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -				
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121				
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156				
LDAC		~~**$ 0.0589**~~		**$ 0.1444**				**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55								
Energy Efficiency Charge	~~$ 0.0441~~		$ 0.0408					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0441~~		$ 0.0408	~~$ 0.0426~~	$ 0.0408		
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155	~~$ 0.0153~~	$ 0.0155		
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0206)~~		$ 0.0039	~~$ (0.0241)~~	$ 0.0039	~~$ (0.0213)~~	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121	~~$ 0.0017~~	$ 0.0121		
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156	~~$ 0.0123~~	$ 0.0156		
LDAC		~~**$ 0.0555**~~		**$ 0.0878**	~~**$ 0.0478**~~	**$ 0.0878**		**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56								
Energy Efficiency Charge	~~$ 0.0441~~		$ 0.0408					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0441~~		$ 0.0408	~~$ 0.0426~~	$ 0.0408		
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155	~~$ 0.0153~~	$ 0.0155		
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0206)~~		$ 0.0039	~~$ (0.0241)~~	$ 0.0039	~~$ (0.0213)~~	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121	~~$ 0.0017~~	$ 0.0121		
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156	~~$ 0.0123~~	$ 0.0156		
LDAC		~~**$ 0.0555**~~		**$ 0.0878**	~~**$ 0.0478**~~	**$ 0.0878**		**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57, G-58								
Energy Efficiency Charge	~~$ 0.0441~~		$ 0.0408					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0441~~		$ 0.0408	~~$ 0.0426~~	$ 0.0408		
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155	~~$ 0.0153~~	$ 0.0155		
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0206)~~		$ 0.0039	~~$ (0.0241)~~	$ 0.0039	~~$ (0.0213)~~	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121	~~$ 0.0017~~	$ 0.0121		
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156	~~$ 0.0123~~	$ 0.0156		
LDAC		~~**$ 0.0555**~~		**$ 0.0878**	~~**$ 0.0478**~~	**$ 0.0878**		**per therm**

Issued: ~~October xx, 2020~~ October xx, 2021 Issued by: ______________________
Neil Proudman
Effective: ~~November 1, 2020~~ November 1, 2021 Title: President

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III DELIVERY TERMS AND CONDITIONS

NHPUC NO. 11 - GAS **Proposed Second Revised Page 153**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 153**

2 ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	~~$ 0.12~~	$ 0.18	
II.	Capacity Mitigation Fee	~~15%~~	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
III.	Peaking Demand Charge	~~$ 17.32~~	$ 54.72	
IV.	Company Allowance Calculation (per Schedule 25)			
		~~169,030,868~~	165,859,380	Total Sendout - Therms Jul -2020 - Jun-2021 ~~Total Sendout - Therms Jul-2019 - Jun-2020~~
		~~166,311,578~~	163,831,092	Total Throughput - Therms Jul-2020 - Jun-2021 ~~Total Throughput - Therms Jul-2019 - Jun-2020~~
		~~2,719,290~~	2,028,288	Variance (Sendout - Throughput)
Company Allowance Percentage	2021-22 ~~2020-21~~	~~1.6%~~	1.2%	Variance / Total Sendout

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ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	~~46.1%~~ 69.1%	~~17.1%~~ 16.8%	~~36.8%~~ 14.1%	100.0%
G-51	Low Annual /Low Winter Use	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%
G-42	Medium Annual / High Winter	~~46.1%~~ 69.1%	~~17.1%~~ 16.8%	~~36.8%~~ 14.1%	100.0%
G-52	High Annual / Low Winter Use	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%
G-43	High Annual / High Winter	~~46.1%~~ 69.1%	~~17.1%~~ 16.8%	~~36.8%~~ 14.1%	100.0%
G-53	High Annual / Load Factor < 90%	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%
G-54	High Annual / Load Factor > 90%	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%

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

Table of Contents

Ln	Description	Reference		PK 21-22
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty**			
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 21-22
6		Reference		Nov - Apr
7	(a)	(b)		(c)
8				
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (k), ln 46	$	12,887,000
12	Supply Costs	Sch. 6, col (i), ln 47		72,351,034
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (k), ln 61	$	981,898
16	Commodity Costs:	Sch. 6, col (i), ln 50		6,130,435
17				
18	Produced Gas:	Sch. 6, col (i), ln 56	$	2,299,384
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	-
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 172	$	-
22				
23	**Total Unadjusted Cost of Gas**		$	94,649,751
24				
25	**Adjustments:**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	1,431,639
28	Interest 05/01/20 - 4/30/21	Sch. 3, col (q) ln 189		44,085
29	Fuel Inventory Revenue Req	Sch. 26, col (b) ln 8		335,667
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(3,600)
32	Fuel Financing	Sch. 4, ln 26 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		(6,938)
34	Interruptible Sales Margin	Sch. 4, ln 26 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)		(1,676,512)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
37	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		36,800
38				
39	**Total Adjustments**		$	161,141
40				
41	**Total Anticipated Direct Costs**	lns 23 + 39	$	94,810,891
42				
43	**Anticipated Indirect Cost of Gas**			
44	**Working Capital**			
45	Total Unadjusted Anticipated Cost of Gas	Ln 23	$	94,649,751
46	Lead Lag Days / 365	DG 20-105, 25.72/ 365		0.0705
47	Prime Rate			3.25%
48	Working Capital Percentage	per GTC 18(f), ln 47 * ln 48		0.229%
49	Working Capital	ln 45 * ln 48		216,761
50	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 94		(14,859)
51				
52	**Total Working Capital Allowance**	lns 49 + 50	$	201,902
53				
54	**Bad Debt**			
55	Total Unadjusted Anticipated Cost of Gas	ln 23	$	94,649,751
56	Less Refunds	ln 30		-
57	Plus Working Capital	ln 52		201,902
58	Plus Prior Period (Over) Under Recovery	ln 27		1,431,639
59	Subtotal		$	96,283,291
60	Bad Debt Percentage	per GTC 18(f)		0.70%
61				
62	Bad Debt Allowance	ln 59 * ln 60	$	673,983
63	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 169		(223,340)
64				
65	**Total Bad Debt Allowance**	lns 62 + 63	$	450,643
66				
67	**Production and Storage Capacity**	per GTC18(f)	$	3,685,458
68				
69				
70	**Miscellaneous Overhead**	lns 69 * 72	$	-
71				
72	**Total Anticipated Indirect Cost of Gas**	lns 52 + 65 + 67 + 70	$	4,338,002
73				
74	**Total Cost of Gas**	lns 41 + 72	$	99,148,894
75				
76	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		87,443,741

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

Ln				Peak Costs								Peak Period
5												
6												
7	For Month of:			May 21 - Oct 21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Nov - Apr
8		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**											
10											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
16												
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
18												
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
34												
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
37												
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
42												
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)
48												
49	Total Firm Sendout Volumes		lns 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
50												

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

REDACTED
Updated Schedule 1
Page 2 of 4

Ln												
51	**II. Gas Costs**											
52	**A.**	**Demand Costs**										
53												
54												
55				Peak Costs								Peak Period
56	For Month of:			May 21 - Oct 21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Nov - Apr
57		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
58	Supply											
59		Niagara Supply	Sch.5A, ln 12	[redacted]								
60		Subtotal Supply Demand										
61		Less Capacity Credit										
62		Net Pipeline Demand Costs										
63												
64	Pipeline:											
65		Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]								
66		Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, ln 17									
67		Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18									
68		Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19									
69		Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20									
70		Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21									
71		Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22									
72		Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	Sch.5A, ln 23									
73		Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 24									
74		Portland Natural Gas Trans Service	Sch.5A, ln 25									
75		Portland Natural Gas	Sch.5A, ln 26									
76		ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 27									
77		TransCanada via Union to Portland	Sch.5A, ln 28									
78		Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 29									
79		Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 30									
80		Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 31									
81		National Fuel FST 2358	Sch.5A, ln 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		$ 13,559,298
83		Less Capacity Credit		(1,320,558)	(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		$ 9,805,576
85												
86	Peaking Supply:											
87		Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 37	[redacted]								
88		Demand FLS	Sch.5A, ln 38									
89		Constellation Demand	Sch.5A, ln 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
93												
94	Storage:											
95		Dominion - Demand	Sch.5A, ln 49	[redacted]								
96		Dominion - Storage	Sch.5A, ln 50									
97		Honeoye - Demand	Sch.5A, ln 51									
98		National Fuel - Demand	Sch.5A, ln 52									
99		National Fuel - Capacity	Sch.5A, ln 53									
100		Tenn Gas Pipeline - Demand	Sch.5A, ln 54									
101		Tenn Gas Pipeline - Capacity	Sch.5A, ln 55									
102		Subtotal Storage Demand		$ 696,628	$ 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)		(411,359)
104		Net Storage Demand Costs		$ 460,750	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858		$ 981,898
105												
106		Total Demand Charges	lns 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		$ 19,071,554
107	v	Total Capacity Credit	lns 61 + 83 + 91 + 103	(1,556,436)	(642,289)	(642,289)	(642,289)	(642,289)	(642,289)	(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		$ 13,868,897
109												
110												

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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 **Summary of Supply and Demand Forecast**

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Updated Schedule 1
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Ln		(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)
111	**B.**	**Commodity Costs**										
118	Pipeline:											
119		Dawn Supply	Sch. 6, ln 12	[redacted]								
120		Niagara Supply	Sch. 6, ln 13									
121		TGP Supply (Direct)	Sch. 6, ln 14									
122		Dracut Supply 1 - Baseload	Sch. 6, ln 15									
123		Dracut Supply 2 - Swing	Sch. 6, ln 16									
		Dracut Supply 3 - Swing	Sch. 6, ln 17									
124		Constellation COMBO	Sch. 6, ln 18									
125		LNG Truck	Sch. 6, ln 19									
126		Propane Truck	Sch. 6, ln 20									
127		PNGTS	Sch. 6, ln 21									
128		Portland Natural Gas	Sch. 6, ln 22									
129		TGP Supply (Z4)	Sch. 6, ln 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	Storage:											
133		TGP Storage - Withdrawals	Sch. 6, ln 50	$ -	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423		$ 6,130,435
134												
135	Produced Gas Costs:											
136		LNG Vapor	Sch. 6, ln 53	[redacted]								
137		Propane	Sch. 6, ln 54									
138		Subtotal Produced Gas Costs		$ -	$ 14,924	$ 296,153	$ 644,056	$ 1,138,771	$ 190,796	$ 14,685		$ 2,299,384
139												
140	Less Storage Refills:											
141		LNG Truck	Sch. 6, ln 40	[redacted]								
142		Propane	Sch. 6, ln 41									
143		TGP Storage Refill	Sch. 6, ln 42									
144		Storage Refill (Trans.)	Sch. 6, ln 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	**C. Supply Volumetric Transportation Costs:**											
150		Dawn Supply	Sch. 6, ln 28	[redacted]								
151		Niagara Supply	Sch. 6, ln 29									
152		TGP Supply (Direct)	Sch. 6, ln 30									
153		Dracut Supply 1 - Baseload	Sch. 6, ln 31									
154		Dracut Supply 2 - Swing	Sch. 6, ln 32									
		Dracut Supply 3 - Swing	Sch. 6, ln 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, ln 35	$ -	$ 38,503	$ 11,890	$ 76,971	$ 68,398	$ 66,579	$ 17,849		$ 280,188
158												
159		Total Supply Volumetric Trans. Costs	lns 155 + 157	$ -	$ 288,190	$ 216,647	$ 275,048	$ 239,882	$ 238,945	$ 59,504		$ 1,318,217
160												
161	Total Commodity Gas & Trans. Costs		lns 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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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
164 **D. Supply and Demand Costs by Source**

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Updated Schedule 1
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Line			Peak Costs	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Peak Period Nov - Apr
170	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
171	Purchased Gas Demand Costs										
172	Pipeline Gas Demand Costs	Ins 60 + 82	$ 3,900,053	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874		$ 13,559,298
173	Peaking Gas Demand Costs	In 90	-	823,800	823,800	823,800	823,800	823,800	-		4,119,000
174	Subtotal Purchased Gas Demand Costs		$ 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	Less Capacity Credit	Ins 61 + 83 + 91	(1,320,558)	(613,043)	(613,043)	(613,043)	(613,043)	(613,043)	(405,527)		(4,791,298)
176	Net Purchased Gas Demand Costs		$ 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											
178	Storage Gas Demand Costs										
179	Storage Demand	In 102	$ 696,628	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105		$ 1,393,257
180	Less Capacity Credit	In 103	(235,878)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)		(411,359)
181	Net Storage Demand Costs		$ 460,750	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858		$ 981,898
182											
183	**Total Demand Costs**	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											
185	Purchased Gas Supply										
186	Commodity Costs	In 130	[redacted]								
187	Less Storage Inj.(TGP Storage)	In 143									
188	Less Storage Transportation	In 144									
189	Less LNG Truck	In 141									
190	Less Propane Truck	In 142									
191	Plus Transportation Costs	In 155									
192	Subtotal Purchased Gas Supply		$ -	$ 5,661,016	$ 25,974,930	$ 19,219,483	$ 10,996,684	$ 7,336,724	$ 2,882,009		$ 72,070,845
193											
194	Storage Commodity Costs										
195	Commodity Costs	In 133	$ -	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423		$ 6,130,435
196	Transportation Costs	In 157	-	38,503	11,890	76,971	68,398	66,579	17,849		280,188
197	Subtotal Storage Commodity Costs		$ -	$ 876,979	$ 270,810	$ 1,753,181	$ 1,557,903	$ 1,516,478	$ 435,272		$ 6,410,624
198											
199	Produced Gas Commodity Costs	In 138	$ -	$ 14,924	$ 296,153	$ 644,056	$ 1,138,771	$ 190,796	$ 14,685		$ 2,299,384
200											
201	**Subtotal Commodity Costs**	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											
203	Hedge Contract (Savings)/Loss		$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
204											
205	**Total Commodity Costs**	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											
207	**Total Demand Costs**	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	**Total Supply Costs**	In 205	-	6,552,919	26,541,893	21,616,721	13,693,357	9,043,998	3,331,966		80,780,853
209											
210	**Total Direct Gas Costs**	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
211											
212											

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

Updated Schedule 2

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

Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
(a)	(b)	(c)	(d)	(e)	(f)
Demand Costs					
Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	[redacted]
Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	[redacted]
National Fuel - Capacity Reservation	FSS-O02357	Storage	ACQ	670,800	[redacted]
Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	[redacted]
Dominion - Demand	GSS 300076	Storage	MDQ	934	[redacted]
National Fuel - Demand	FSS-O02357	Storage	MDQ	6,098	[redacted]
National Fuel	FST N02358	Transportation	MDQ	6,098	[redacted]
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	[redacted]
Tenn Gas Pipeline	358905 FTA Z6-Z6	Transportation	MDQ	40,000	[redacted]
Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	[redacted]
Honeoye - Demand	SS-NY	Storage	MDQ	1,362	[redacted]
Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	[redacted]
Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	[redacted]
Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	[redacted]
Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	[redacted]
Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	[redacted]
Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	[redacted]
Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	[redacted]
ANE (TransCanada via Union to Iroquois)	Dawn - Parkway to Iroquois	Transportation	MDQ	4,047	[redacted]
TransCanada via Union to Portland	Dawn -Parkway to Portland	Transportation	MDQ	5,077	[redacted]
Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	[redacted]
Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	[redacted]
Portland Natural Gas Trans Service	FT-208544	Transportation	MDQ	1,000	[redacted]
Portland Natural Gas	FT 233320	Transportation	MDQ	5,000	[redacted]
Peaking Demand	NSB041	Peaking	MDQ	10,000	[redacted]
Supply Costs - Commodity					
TGP Supply (Z4)		Pipeline	Dkt	1,475,358	[redacted]
Niagara Supply		Pipeline	Dkt	421,275	[redacted]
Constellation COMBO		Pipeline	Dkt	434,541	[redacted]
TGP Supply (Direct)		Pipeline	Dkt	1,728,355	[redacted]
Dawn Supply		Pipeline	Dkt	523,333	[redacted]
Dracut Supply 1 - Baseload		Pipeline	Dkt	1,065,077	[redacted]
TGP Storage		Storage	Dkt	1,999,970	[redacted]
PNGTS		Pipeline	Dkt	131,394	[redacted]
Propane Truck		Pipeline	Dkt	69,507	[redacted]
LNG Truck		Pipeline	Dkt	74,782	[redacted]
Dracut Supply 2 - Swing		Pipeline	Dkt	916,571	[redacted]
Dracut Supply 3 - Swing		Pipeline	Dkt	88,843	[redacted]
Portland Natural Gas		Pipeline	Dkt	628,497	[redacted]
Propane		Produced	Dkt	81,802	[redacted]
LNG Vapor (Storage)		Produced	Dkt	197,875	[redacted]
Supply Costs - Volumetric Transportation					
Dracut Supply 1 - Baseload		Pipeline	Dkt	1,065,077	[redacted]
Dracut Supply 2 - Swing		Pipeline	Dkt	916,571	[redacted]
Niagara Supply		Pipeline	Dkt	421,275	[redacted]
Dawn Supply		Pipeline	Dkt	523,333	[redacted]
TGP Storage - Withdrawals		Pipeline	Dkt	1,999,970	[redacted]
TGP Supply (Direct)		Pipeline	Dkt	1,728,355	[redacted]

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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**

5			Prior Period Bal														
6			Apr-21														
7			Ending 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
8		Days in Month	Plus May Billings	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Account 1920-1740 COG (Over)/Under Balance - Interest Calculation**																
12	**Beginning Balance**	Account 1920-1740 1/	**$ 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	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
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	614,243	614,243	614,243	614,243	614,243	614,243		3,685,458
15	Projected Revenues w/o Int.	ln 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)
16	Projected Unbilled Revenue									(9,688,864)	(10,291,768)	(10,832,213)	(10,950,320)	(11,192,067)	(10,918,387)		(63,873,618)
17	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
18	Adjustment			(1,233,644)	(1,008,659)					-							(2,242,302)
19	Add Net Adjustments	Schedule 4		-	-	-	-	-	-	(243,108)	(283,455)	(283,617)	(282,374)	(279,025)	(278,672)	-	(1,650,251)
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	(ln 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)	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
26	Interest Applied	ln 22 * ln 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
28	**(Over)/Under Balance**	ln 21 + ln 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
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	ln 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
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 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
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	614,243	614,243	614,243	614,243	614,243	614,243	-	3,685,458
36	Projected Revenues with int.	ln 52 * ln 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)
37	Projected Unbilled Revenue									(9,693,964)	(10,297,185)	(10,837,914)	(10,956,084)	(11,197,958)	(10,924,134)		(63,907,240)
38	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
39	Add Net Adjustments	ln 19		(1,233,644)	(1,008,659)	-	-	-	-	(243,108)	(283,455)	(283,617)	(282,374)	(279,025)	(278,672)	-	(3,892,553)
40	Gas Cost Billed	ln 20	-		-	-	-	-	-	-	-	-	-	-	-	-	-
41	Add Interest	ln 26		-	-	-	-	-	-	222	6,298	19,117	13,793	3,306	(10,117)	-	32,618
42	**(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)	
46	Interest Applied	ln 24 * ln 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
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 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
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, ln 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	
59	COB w/o Interest	Sch. 3, pg. 4, ln 207 col. (c)								$1.0964	$1.0964	$1.0964	$1.0964	$1.0964	$1.0964	$1.0964	
61	COG With Interest	Sch. 3, pg. 4, ln 207 col. (d)								$1.0970	$1.0970	$1.0970	$1.0970	$1.0970	$1.0970	$1.0970	

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**

Ln			Prior Period Bal Apr-21 Ending Bal + May Collections	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 Total
67		Days in Month		31	30	31	31	30	31	30	31	31	28	31	30	31	
68	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
70	**Account 1163-1422 Working Capital (Over)/Under Balance - Interest Calculation**																
72	**Beginning Balance**	Account 1163-1422 1/	**$ (14,859)**	$ (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)	$ (14,859)
74	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		
75	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%		
76	Forecast Working Capital	ln 34 * 0.091%		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
78	Projected Revenues w/o Int.	ln 116 * ln 120		-	-	-	-	-	-	(7,213)	(40,427)	(47,306)	(39,883)	(34,010)	(20,551)	(9,856)	(199,245)
79	Projected Unbilled Revenue									(20,135)	(21,388)	(22,511)	(22,757)	(23,259)	(22,690)		(132,741)
80	Reverse Prior Month Unbilled										20,135	21,388	22,511	22,757	23,259	22,690	132,741
82	Add Net Adjustments			(1,062)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	(2,657)
84	Working Capital Billed	Account 1163-1422 2/	-														-
86	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
88	Average Monthly Balance	(ln 72 + ln 86)/2		$ (14,810)	$ (15,019)	$ (14,696)	$ (13,576)	$ (12,453)	$ (11,326)	$ (14,763)	$ (7,052)	$ 7,387	$ 7,930	$ 1,033	$ (8,377)	$ (6,679)	
90	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%		
92	Interest Applied	ln 88 * ln 90 / 365 * Days of Month		$ (41)	$ (40)	$ (41)	$ (37)	$ (33)	$ (31)	$ (39)	$ (19)	$ 20	$ 20	$ 3	$ (22)	$ -	$ (262)
94	**(Over)/Under Balance**	ln 86 + ln 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)
97	**Calculation of Working Capital with Interest**																
100	**Beginning Balance**	ln 72	$ (14,859)	$ (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)	$ (14,859)
101	Forecast Working Capital	ln 76		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	ln 116 * ln 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	ln 82	-	(1,062)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	(2,657)
106	Working Capital Billed	ln 84	-	-	-	-	-	-	-								-
107	Add Interest	ln 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
110	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)	
112	Interest Applied	ln 90 * ln 110 / 365 * Days of Month		(41)	(40)	(41)	(37)	(33)	(31)	(39)	(19)	21	20	4	(22)	-	$ (259)
114	**(Over)/Under Balance**	-ln 107 +ln 108 + ln 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
116	Forecast Therm Sales	ln 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
117	Unbilled Therm	ln 55								8,836,890	549,888	492,921	107,722	220,489	(249,614)		
118	Gross Unbilled									8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296		
120	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 224 col. (c)								$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	
122	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 224 col. (d)								$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**

Ln	(a)	Days in Month (b)	Prior Period Bal Apr-21 Ending Bal + May Collections	May-21 31 (c)	Jun-21 30 (d)	Jul-21 31 (e)	Aug-21 31 (f)	Sep-21 30 (g)	Oct-21 31 (h)	Nov-21 30 (i)	Dec-21 31 (j)	Jan-22 31 (k)	Feb-22 28 (l)	Mar-22 31 (m)	Apr-22 30 (n)	May-22 31 (o)	DemandPeriod Total (p)
130	**Account 1920-1743 Bad Debt (Over)/Under Balance - Interest Calculation**																
132	Forecast Direct Gas Costs	ln 34		$ 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
133	Forecast Working Capital	ln 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	ln 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
137	**Beginning Balance**	Account 1920-1743 1/	**$ (223,340)**	$ (223,340)	$ (252,014)	$ (257,764)	$ (254,915)	$ (252,059)	$ (249,172)	$ (246,300)	$ (242,363)	$ (127,460)	$ (60,766)	$ (32,419)	$ (25,087)	$ (32,220)	$ (223,340)
139	Forecast Bad Debt	ln 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
141	Projected Revenues w/o int	ln 178 * ln 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
145	Bad Debt Billed	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
147	Add Net Adjustments		-	(31,575)	(8,627)	-	-	-	-		-	-	-	-	-	-	(40,203)
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
151	Average Monthly Balance	(ln 137 + ln 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)	
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%		
155	Interest Applied	ln 151 * ln 153 / 365 * Days of Month		$ (653)	$ (678)	$ (707)	$ (699)	$ (669)	$ (683)	$ (652)	$ (510)	$ (259)	$ (116)	$ (79)	$ (76)		$ (5,781)
157	**(Over)/Under Balance**	ln 149 + ln 155	$ (223,340)	$ (252,014)	$ (257,764)	$ (254,915)	$ (252,059)	$ (249,172)	$ (246,300)	$ (242,363)	$ (127,460)	$ (60,766)	$ (32,419)	$ (25,087)	$ (32,220)	$ (5,781)	(5,781)
160	**Calculation of Bad Debt with Interest**																
162	**Beginning Balance**	ln 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	ln 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.	ln 178 * ln 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)	(46,094)		(269,654)
166	Reverse Prior Month Unbilled										40,903	43,449	45,730	46,229	47,249	46,094	269,654
167	Bad Debt Billed	ln 145	-		-	-	-	-	-	-	-	-	-	-	-	-	0
168	Add Interest	ln 155		-	-	-	-	-	-	(652)	(510)	(259)	(116)	(79)	(76)	-	(1,693)
169	Add Net Adjustments	ln 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
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)	
174	Interest Applied	ln 153 * ln 172 / 365 * Days of Month		(655)	(680)	(707)	(699)	(669)	(683)	(652)	(507)	(259)	(116)	(79)	(76)	-	$ (5,781)
176	**(Over)/Under Balance**	-ln 168 +ln 170 + ln 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)
178	Forecast Term Sales	ln 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	ln 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		
182	COG Rate Without Interest	Sch. 3, pg. 4, ln 241 col. (c)								$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	
184	COG With Interest	Sch. 3, pg. 4, ln 241 col. (d)								$0.0046	$0.0046	$0.0046	$0.0046	$0.0046	$0.0046	$0.0046	
189	**Total Interest**	lns 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

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

REDACTED
Updated Schedule 4
Page 1 of 1

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**
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
May-20		$ -	$ -	$ -	$ -	$ -	$ -	[redacted]	[redacted]	$ -	$ -	$ -
Jun-20		-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
Jul-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
Aug-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
Sep-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
Oct-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
Nov-20	1/	-	-	(47)	-	(1,032)	-	[redacted]	[redacted]	-	36,800	(243,108)
Dec-20	1/	-	-	(624)	-	(1,276)	-	[redacted]	[redacted]	-	-	(283,455)
Jan-21	1/	-	-	(751)	-	(1,436)	-	[redacted]	[redacted]	-	-	(283,617)
Feb-21	1/	-	-	(816)	-	(1,199)	-	[redacted]	[redacted]	-	-	(282,374)
Mar-21	1/	-	-	(757)	-	(1,145)	-	[redacted]	[redacted]	-	-	(279,025)
Apr-21	1/	-	-	(605)	-	(851)	-	[redacted]	[redacted]	-	-	(278,672)
Subtotal May 20 - Oct 20		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Nov 20 - Apr 21		$ -	$ -	$ (3,600)	$ -	$ (6,938)	$ -	$ -	$ (1,676,512)	$ -	$ 36,800	$ (1,650,251)
Total Peak Period		$ -	$ -	$ (3,600)	$ -	$ (6,938)	$ -	$ -	$ (1,676,512)	$ -	$ 36,800	$ (1,650,251)

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.**										**REDACTED**
2	**d/b/a Liberty**										**Updated Schedule 5A**
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**										**Page 1 of 1**
4	**Demand Costs**										
5											
6				Deferred							Peak
7				to Peak							Nov-Apr
8		Peak	Reference	May 20 -Oct 20	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	[redacted]							
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	peak	Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	peak	Sch 5B, ln 19 * Sch 5C ln 25 x days								
24	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 20 * Sch 5C ln 28 x days								
25	Portland Natural Gas Trans Service		Sch 5B, ln 21 * Sch 5C ln 30 x days								
26	Portland Natural Gas		Sch 5B, ln 22 * Sch 5C ln 31 x days								
27	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 23 * Sch 5C ln 32 x days								
28	TransCanada via Union to Portland		Sch 5B, ln 24 * Sch 5C ln 33 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 25 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 36 x days								
31	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 27 * Sch 5C ln 38 x days								
32	National Fuel FST 2358	peak	Sch 5B, ln 28 * Sch 5C ln 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, ln 31 * Sch 5C ln 28 x days	[redacted]							
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**		ln 13 + ln 34 + ln 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, ln 36 * Sch 5C ln 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, ln 37 * Sch 5C ln 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, ln 38 * Sch 5C ln 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, ln 40 * Sch 5C ln 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, ln 41 * Sch 5C ln 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, ln 42 * Sch 5C ln 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, ln 43 * Sch 5C ln 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**		ln 57 + ln 59	$ 460,750	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 981,898
62											
63	**Total Demand Charges**		ln 42 + ln 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		ln 44 + ln 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.**		ln 63 + ln 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				**THIS PAGE HAS BEEN REDACTED**							

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

Updated Schedule 5B

	Peak	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply								
Niagara Supply			-	-	-	-	-	-
Pipeline								
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
Peaking								
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	-
Storage								
Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
Honeoye - Capacity	peak	SS-NY	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

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

REDACTED
Updated Schedule 5C
Page 1 of 2

				Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov - Apr
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagara Supply		[redacted]		[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$ 5.2357	Forth Revised Sheet No. 4	$ 0.1745	$ 0.1689	$ 0.1689	$ 0.1870	$ 0.1689	$ 0.1745	$ 0.1738
Tenn Gas Pipeline	95346 Z5-Z6	$ 6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
Tenn Gas Pipeline	2302 Z5-Z6	$ 6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
Tenn Gas Pipeline	8587 Z0-Z6	$ 20.3736	FT-A (Z0 - Z6)	$ 0.6791	$ 0.6572	$ 0.6572	$ 0.7276	$ 0.6572	$ 0.6791	$ 0.6763
Tenn Gas Pipeline	8587 Z1-Z6	$ 18.0875	FT-A (Z1 - Z6)	$ 0.6029	$ 0.5835	$ 0.5835	$ 0.6460	$ 0.5835	$ 0.6029	$ 0.6004
Tenn Gas Pipeline	8587 Z4-Z6	$ 7.1645	FT-A (Z4 - Z6)	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
TGP Dracut	42076 FTA Z6-Z6	$ 4.1818	17th Rev Sheet No. 14	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394	$ 0.1388
TGP Dracut	358905 FTA Z6-Z6	$ 4.1818	17th Rev Sheet No. 14	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394	$ 0.1388
TGP Concord Lateral	Firm Transportatio	$ 12.2113	Per contract	$ 0.4070	$ 0.3939	$ 0.3939	$ 0.4361	$ 0.3939	$ 0.4070	$ 0.4053
Portland Natural Gas	FT-208544	$ 18.2633	Negot Dmd /CMDY=Part 4.1 V7	$ 0.6088	$ 0.5891	$ 0.5891	$ 0.6523	$ 0.5891	$ 0.6088	$ 0.6062
Portland Natural Gas	FT 233320	$ 22.8125	Negot Dmd /CMDY=Part 4.1 V7	$ 0.7604	$ 0.7359	$ 0.7359	$ 0.8147	$ 0.7359	$ 0.7604	$ 0.7572
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$ 7.1645	17th Rev Sheet No. 14	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$ 7.1645	17th Rev Sheet No. 14	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$ 6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
National Fuel	FST N02358	$ 4.5274	4.010 Version 31.0.1 Pg 1	$ 0.1509	$ 0.1460	$ 0.1460	$ 0.1617	$ 0.1460	$ 0.1509	$ 0.1503

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Line	Description		Contract	Rate	Reference							
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**											**REDACTED**
2	**d/b/a Liberty**											Updated Schedule 5C
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**											Page 2 of 2
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	**Peaking**											
60	Demand FLS			[redacted]		[redacted]						
61	Subtotal Peaking Demand Charges											
62												
63	**Storage**											
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						THIS PAGE HAS BEEN REDACTED						

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.

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 chedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [5] Surcharge (6)	EPCA [6] Surcharge (7)	Current Rate [7] (8)	FERC ACA (9)
[2], [4]								
	Storage Demand	$1.7984	$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]
-E [2], [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.G.
[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) 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

__X___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

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	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

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	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
___X__ 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	Contract Category	Contract Number	Service Type	Status	Currency
Energy North Natural Gas Inc.	**Storage**	**EN-11234**	FT	Active	USD
Deal Maker	Deal Date	Deal Time (hh:mm)	Master Agreement	Units	
Richard Norman	01/17/1986	08:00	-- None --	Dth	
Contact Name	Contact Number 1	Contact Number 2	Contact Email		
Sarah Finegan	603-2163569		sarah.finegan@libertyutilities.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 (hh:mm 24-hr CCT)

Day of Flow Deadline (hh:mm 24-hr CCT)

Transaction Types and Rates

Transaction Type	Allow Transaction Yes	Allow Transaction No	Allow Transaction D.E.R Only	Use Hourly Profiles	Volumetric Charge ($/Dth)	Other Rate ($/Dth)	Fuel Percentage	Invoice Qty Type
Storage Injection	●	○	○	☐	0	0	0	Sch Qty
Storage Withdrawal	●	○	○	☐	0	0	0	Sch Qty
Authorized Injection Overrun	●	○	○	☐	0	0	0	Sch Qty
Authorized Withdrawal Overrun	●	○	○	☐	0	0	0	Sch Qty

Storage and Other Rates

☐ Use Monthly Flat Storage Fee ($/Month)

Monthly Flat Storage Fee Table

From	To	Rate
05/01/10	01/01/50	8,350.69000

FERC Information

Capacity Release Contract: ○ Yes ● No

Shipper Affiliation: NONE

Maximum Tariff Rate: 0 OR ☐ Market Based Rates

Award:

Negotiated Rate Indicator: ● Yes ○ No

Rate Schedule: 157

Contract Quantity Limits

Monthly MSQ Table

From	To	Max Qty	Min Qty
05/01/10	01/01/50	245,280	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

RATES FOR TRANSPORTATION SERVICES

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

The NA15 Retention is 1.11% applicable to use of the Northern Access 2015 Lease. [2/3]

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

2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.84% 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.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Rate [2/] (3)
ESS	Demand	(Max)	$2.6433 [5/]
		(Min)	$0.0000
	Capacity	(Max)	$0.0485 [6/]
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0458 plus ACA [3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$0.0000
ISS	Injection	(Max)	$1.1271 plus ACA [3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$0.0000
FSS	Demand	(Max)	$2.5326 [5/]
		(Min)	$0.0000
	Capacity	(Max)	$0.0462 [6/]
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0439 plus ACA [3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$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	$0.2989	$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 Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0413.

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

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

FIRM TRANSPORTATION RATES
RATE SCHEDULE FT-A

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

	Base Tariff Rate	Total Rate
CP00-65 300 Line Expansion		
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/
CP05-355 Northeast ConneXion - New York/New Jersey Expansion		
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/
CP08-65 Concord Expansion		
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/
CP09-444 300 Line Project – Market Component		
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/
CP11-30-000 Northeast Supply Diversification Project		
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/
CP11-36-000 Northampton Expansion Project		
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.

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

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$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/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
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%.

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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

FUEL AND 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 (23-21): 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	$0.0033	$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 (23-21): 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 IT.
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%.

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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)	Fuel and Commodity Charges			
		Union Supplied Fuel	Shipper Supplied Fuel		
	Rate/GJ	Fuel and Commodity Charge Rate/GJ	Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1), (5)					
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				
M12-X Firm Transportation					
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".		
Limited Firm/Interruptible Transportation (1)					
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%		
Carbon Charge (applied to all quantities transported)					
Facility Carbon Charge		$0.003			$0.003

North Bay Junction Long Term Fixed Price (NBJ LTFP) Service

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

Note: The toll for NBJ LTFP is inclusive of the applicable Abandonment Surcharge for FT service from Empress to North Bay Junction. The NBJ LTFP 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 (a)	Monthly Toll ($/GJ/Month) (b)	Daily Equivalent ($/GJ) (c)	Abandonment Surcharge ($/GJ/Month) (d)	Daily Equivalent Abandonment Surcharge ($/GJ) (e)
3	Union Parkway Belt to Union EDA	9.92374	0.3262	0.44408	0.0146

Delivery Pressure

Line No.	Particulars (a)	Monthly Toll ($/GJ/Month) (b)	Daily Equivalent ($/GJ) (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 Injections, IT, Diversions and STFT.

Union Dawn Receipt Point Surcharge

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

Short Notice Balancing (SNB) Service

Line No.	Particulars (a)	Monthly Toll ($/GJ/Month) (b)	Daily Equivalent ($/GJ) (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 (a)	Capacity Charge ($/GJ/D) (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 ($/GJ/Month)	Daily Equivalent FT for IT / STFT ($/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	-	0.6356	-	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	Napierville	-	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	Philipsburg	-	0.6346	-	0.0347
19	Union NDA	Spruce	-	0.5990	-	0.0660
20	Union NDA	St. Clair	-	0.6177	-	0.0336
21	Union NDA	Welwyn	-	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 SSDA	34.49250	1.1340	3.40667	0.1120
25	Union Parkway Belt	Centram SSDA	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	2.04096	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	0.67829	0.0223
31	Union Parkway Belt	Calstock NDA	18.94350	0.6228	1.32313	0.0435
32	Union Parkway Belt	Tunis 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 SSMDA	16.67746	0.5483	1.16192	0.0382
35	Union Parkway Belt	Union NCDA	6.64604	0.2185	0.27983	0.0092
36	Union Parkway Belt	Union CDA	4.16100	0.1368	0.10950	0.0036
37	Union Parkway Belt	Union ECDA	3.47358	0.1142	0.06388	0.0021
38	Union Parkway Belt	Union EDA	9.02158	0.2966	0.44408	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	0.13688	0.0045
41	Union Parkway Belt	Enbridge Parkway CDA	2.92000	0.0960	0.02433	0.0008
42	Union Parkway Belt	Enbridge EDA	12.02067	0.3952	0.65092	0.0214
43	Union Parkway Belt	KPUC EDA	8.94250	0.2940	0.43800	0.0144
44	Union Parkway Belt	Energir EDA	15.63721	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	0.66308	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	Napierville	15.26004	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	Philipsburg	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	Welwyn	31.72763	1.0431	3.05688	0.1005
61	Union Parkway Belt	Dawn Export	7.41558	0.2438	0.33458	0.0110
62	Union SSMDA	Empress	-	0.8516	-	0.0979
63	Union SSMDA	TransGas SSDA	-	0.7252	-	0.0819
64	Union SSMDA	Centram SSDA	-	0.6344	-	0.0705
65	Union SSMDA	Centram MDA	-	0.5448	-	0.0592
66	Union SSMDA	Centrat MDA	-	0.5385	-	0.0584
67	Union SSMDA	Union WDA	-	0.7145	-	0.0806
68	Union SSMDA	Nipigon WDA	-	1.0474	-	0.0877
69	Union SSMDA	Union NDA	-	0.8256	-	0.0597

Ln									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 1 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 66 * ln 107	[redacted]						
13	Niagara Supply	ln 67 * ln 112							
14	TGP Supply (Direct)	ln 68 * ln 132							
15	Dracut Supply 1 - Baseload	ln 69 * ln 117							
16	Dracut Supply 2 - Swing	ln 70 * ln 122							
17	Dracut Supply 3 - Swing	ln 71 * ln 123							
18	Constellation COMBO	ln 72 * ln 138							
19	LNG Truck	ln 73 * ln 140							
20	Propane Truck	ln 74 * ln 142							
21	PNGTS	ln 75 * ln 147							
22	Portland Natural Gas	ln 76 * ln 152							
23	TGP Supply (Z4)	ln 77 * ln 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	**Volumetric Transportation Costs**								
28	Dawn Supply	ln 66 * ln 204	[redacted]						
29	Niagara Supply	ln 67 * ln 215							
30	TGP Supply (Direct)	ln 68 * ln 242							
31	Dracut Supply 1 - Baseload	ln 69 * ln 263							
32	Dracut Supply 2 - Swing	ln 70 * ln 263							
33	Dracut Supply 3 - Swing	ln 71 * ln 264							
34	Constellation COMBO	ln 72 * ln 263							
35	TGP Storage - Withdrawals	ln 82 * ln 179							
36									
37	**Total Volumetric Transportation Costs**		$ 288,190	$ 216,647	$ 275,048	$ 239,882	$ 238,945	$ 59,504	$ 1,318,217
38									
39	**Less - Gas Refill:**								
40	LNG Truck	ln 91 * ln 164	[redacted]						
41	Propane	ln 92 * ln 165							
42	TGP Storage Refill	ln 93 * ln 130							
43	Storage Refill (Trans.)	ln 93 * ln 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**	ln 25 + ln 37 + ln 45	$ 5,699,518	$ 25,986,820	$ 19,296,454	$ 11,065,081	$ 7,403,303	$ 2,899,858	$ 72,351,034
48									
49	**Storage Gas:**								
50	TGP Storage - Withdrawals	ln 82 * ln 171	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423	$ 6,130,435
51									
52	**Produced Gas:**								
53	LNG Vapor	ln 85 * ln 159	[redacted]						
54	Propane	ln 86 * ln 161							
55									
56	**Total Produced Gas**	ln 53 + ln 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**	ln 47 + ln 50 + ln 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									

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Line									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 2 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
62									
63	**Volumes (Therms)**								
64									
65	**Pipeline Gas:**	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	**Storage Gas:**								
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	**Produced Gas:**								
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	**Less - Gas Refill:**								
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	**Total Sendout Volumes**		12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211	94,216,591
98									
99									
100									

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 3 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
101	**Gas Costs and Volumetric Transportation Rates**								
102									
103	**Pipeline Gas:**								
104	**Dawn Supply**								Average Rate
105	NYMEX Price	Sch 7, ln 10/10	[redacted]						
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Niagara Supply**								
110	NYMEX Price	Sch 7, ln 10/10	[redacted]						
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 1 - Baseload**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119	**Dracut Supply 2 - Swing**								
120	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
121	Basis Differential								
122	**Net Commodity Costs**								
123									
124	**Dracut Supply 3 - Swing**								
125	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
126	Basis Differential								
127	**Net Commodity Costs**								
128									
129	**TGP Supply (Direct)**								
130	NYMEX Price	Sch 7, ln 10/10	[redacted]						
131	Basis Differential								
132	**Net Commodity Costs**								
133									
134									
135	**Constellation COMBO**								
136	NYMEX Price	Sch 7, ln 10/10	[redacted]						
137	Basis Differential								
138	**Net Commodity Costs**								
139									
140	**LNG Truck**	Sch 7, ln 10/10	[redacted]						
141									
142	**Propane Truck**	Propane WACOG	[redacted]						
143									
144	**PNGTS**								
145	NYMEX Price	Sch 7, ln 10/10	[redacted]						
146	Basis Differential								
147	**Net Commodity Cost**								
148									
149	**PNGTS EXP**								
150	NYMEX Price	Sch 7, ln 10/10	[redacted]						
151	Basis Differential								
152	**Net Commodity Cost**								
153									
154	**TGP Supply (Z4)**								
155	NYMEX Price	Sch 7, ln 10/10	[redacted]						
156	Basis Differential								
157	**Net Commodity Cost**								
158									
159	**LNG Vapor (Storage)**	Sch 16, ln 95 /10	[redacted]						
160									
161	**Propane**	Sch 16, ln 66 /10	[redacted]						
162									
163	**Storage Refill:**								
164	**LNG Truck**	ln 140	[redacted]						
165	**Propane**	ln 142							
166									
167						**THIS PAGE HAS BEEN REDACTED**			

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Ln	Description	Reference							
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 4 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
168									
169									
170	**TGP Storage**								
171	**Commodity Costs - Storage withdrawal**	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	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.01399	$0.01399	$0.01399	$0.01399	$0.01399	$0.01437	$0.01405
180									
181	**Total TGP - Comm. & Vol. Trans. Rate**	ln 171 + ln 179	**$0.31856**	**$0.31856**	**$0.31856**	**$0.31856**	**$0.31856**	**$0.35044**	**$0.32387**
182									
183									
184	**Per Unit Volumetric Transportation Rates**								
185	**Dawn Supply Volumetric Transportation Charge**								
186	**Commodity Costs**	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	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01630**	**$0.01706**	**$0.01887**	**$0.01832**	**$0.01677**	**$0.01149**	**$0.01647**
205									
206									
207	**Niagara Supply Volumetric Transportation Charge**								
208	**Commodity Costs**	Ln 112	[redacted]						
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	[redacted]						
215	**Total Volumetric Transportation Rate - Niagara Supply**								
216									
217					**THIS PAGE HAS BEEN REDACTED**				

Ln									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 5 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
218									
219									
220									
221	**TGP Direct Volumetric Transportation Charge**								Average Rate
222	**Commodity Costs**	Ln 130	[redacted]						
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	ln 222 x ln 236	**$0.00849**	**$0.00874**	**$0.00889**	**$0.00874**	**$0.00825**	**$0.00623**	**$0.00822**
241	TGP - Fuel Charge % - Z 1-6	ln 222 x ln 239	**$0.01530**	**$0.01574**	**$0.01602**	**$0.01573**	**$0.01486**	**$0.01121**	**$0.01481**
242	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04833**	**$0.04902**	**$0.04945**	**$0.04901**	**$0.04765**	**$0.04198**	**$0.04757**
243									
244	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
245	**Commodity Costs**	Ln 130	[redacted]						
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	ln 245 x ln 250	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**
252	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**
253									
254									
255	**TGP Dracut**								
256	**Commodity Costs - NYMEX Price**	Ln 117	[redacted]						
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 - Z6-6	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	ln 256 x ln 261	[redacted]						
263	**Total Volumetric Transportation Rate - TGP Dracut**								
264									
265					**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty** Updated Schedule 7
3 **Peak 2021 - 2022 Winter Cost of Gas Filing** Page 1 of 1
4 **NYMEX Futures @ Henry Hub**
5

Line	For Month of:	Reference		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak 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		**Filed COG**	$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)**

Line				Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
8	**PROPOSED**									
10	**average 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										
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**

33
34 **November 1, 2020 - April 30, 2021**
35 **Residential Heating (R3)**

Line				Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
36	**CURRENT**									
38	**average Usage (Therms)**			62	110	123	148	132	92	667
39										
40	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
41	Cust. Chg	$ 15.50	$ 15.39	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 93.00
42	Headblock	$ 0.5678	$ 0.5632							
43	Tailblock	$ 0.5678	$ 0.5632	$ 35.20	$ 62.46	$ 69.84	$ 84.03	$ 74.95	$ 52.24	$ 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	**Total Bill**			**$ 88.90**	**$ 145.72**	**$ 149.95**	**$ 171.54**	**$ 166.28**	**$ 128.82**	**$ 851.20**

61
62 **DIFFERENCE:**

Line								
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	**118.89%**	**118.89%**	**161.45%**	**185.18%**	**136.51%**	**101.56%**	**139.09%**

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**

4
5
6 **November 1, 2021 - April 30, 2022**
7 **Commercial Rate (G-41)**

Line				Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
8	**PROPOSED**									
10	**average Usage (Therms)**			89	277	504	457	331	297	1,955
11										
12	**Winter:**		8/1/2021 - Current							
13	Cust. Chg		$ 57.06	$ 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	$ 46.88	$ 276.12
15	Tailblock		$ 0.3149	$ -	$ 55.74	$ 127.22	$ 112.42	$ 72.74	$ 62.04	$ 430.15
16	HB Threshold		100							
17										
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**

33
34 **November 1, 2020 - April 30, 2021**
35 **Commercial Rate (G-41)**

Line				Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
36	**CURRENT**									
38	**average Usage (Therms)**			89	277	504	457	331	297	1,955
39										
40	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
41	Cust. Chg	$ 57.46	$ 57.06	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 344.76
42	Headblock	$ 0.4711	$ 0.4688	$ 41.93	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 277.48
43	Tailblock	$ 0.3165	$ 0.3149	$ -	$ 56.02	$ 127.87	$ 112.99	$ 73.11	$ 62.35	$ 432.34
44	HB Threshold	100	100							
45										
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**

61
62 **DIFFERENCE:**

Line										
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			110.09%	110.09%	151.11%	174.00%	127.06%	93.40%	132.45%

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Line	Description	7/1/20 - 7/31/21	8/1/2021 - Current	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
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**									**Winter**
77				**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Nov-Apr**
78	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,131
79			8/1/2021 - Current							
80	**Winter:**									
81	Cust. Chg		$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14
82	Headblock		$ 0.4261	$ 353.66	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 2,484.16
83	Tailblock		$ 0.2839	$ -	$ 337.56	$ 768.80	$ 683.06	$ 455.09	$ 396.04	$ 2,640.55
84	HB Threshold		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	**Total Bill**			**$ 1,539.04**	**$ 3,609.60**	**$ 5,896.92**	**$ 5,442.17**	**$ 4,233.01**	**$ 3,919.80**	**$ 24,640.53**
101										
102	**November 1, 2020 - April 30, 2021**									
103	**C&I High Winter Use Medium G-42**									
104	**CURRENT**									**Winter**
105				**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Nov-Apr**
106	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,131
107										
108	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
109	Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34
110	Headblock	$ 0.4284	$ 0.4261	$ 355.57	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 2,497.57
111	Tailblock	$ 0.2855	$ 0.2839	$ -	$ 339.46	$ 773.13	$ 686.91	$ 457.66	$ 398.27	$ 2,655.44
112	HB Threshold	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	**Total Bill**			**$ 1,034.84**	**$ 2,277.07**	**$ 3,302.08**	**$ 2,926.67**	**$ 2,540.07**	**$ 2,576.41**	**$ 14,657.15**
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)**

Row			Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
144	**PROPOSED**								
146	**average Usage (Therms)**		1,352	1,866	2,284	2,160	1,886	1,760	11,308
147									
148	**Winter:**	8/1/2021 - Current							
149	Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14
150	Headblock	$ 0.2428	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 1,456.80
151	Tailblock	$ 0.1617	$ 56.92	$ 140.03	$ 207.62	$ 187.57	$ 143.27	$ 122.89	$ 858.30
152	HB Threshold	1,000							
153									
160	Total Base Rate Amount		$ 470.91	$ 554.02	$ 621.61	$ 601.56	$ 557.26	$ 536.88	$ 3,342.24
161									
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
164									
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
167									
168	**Total Bill**		**$2,120.63**	**$2,830.93**	**$3,408.57**	**$3,237.21**	**$2,858.57**	**$2,684.45**	**$17,140.34**

169
170 **November 1, 2020 - April 30, 2021**
171 **Commercial Rate (G-52)**

Row				Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
172	**CURRENT**									
174	**average Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,308
175										
176	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
177	Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34
178	Headblock	$ 0.2439	$ 0.2428	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 1,463.40
179	Tailblock	$ 0.1624	$ 0.1617	$ 57.16	$ 140.64	$ 208.52	$ 188.38	$ 143.89	$ 123.42	$ 862.02
180	HB Threshold	1,000	1,000							
181										
188	Total Base Rate Amount			$ 473.45	$ 556.93	$ 624.81	$ 604.67	$ 560.18	$ 539.71	$ 3,359.76
189										
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
192										
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
195										
196	**Total Bill**			**$1,313.72**	**$1,716.65**	**$1,837.16**	**$1,667.39**	**$1,654.06**	**$1,717.86**	**$9,906.84**

197
198 **DIFFERENCE:**

Row								
199	**Total Bill**	**$ 806.91**	**$ 1,114.28**	**$ 1,571.41**	**$ 1,569.82**	**$ 1,204.51**	**$ 966.59**	**$ 7,233.51**
200	% Change	**61.42%**	**64.91%**	**85.53%**	**94.15%**	**72.82%**	**56.27%**	**73.02%**
201								
202	**Base Rate**	$ (2.55)	$ (2.91)	$ (3.20)	$ (3.11)	$ (2.92)	$ (2.83)	$ (17.52)
203	% Change	-0.54%	-0.52%	-0.51%	-0.51%	-0.52%	-0.52%	-0.52%
204								
205	**COG & LDAC**	$ 809.45	$ 1,117.19	$ 1,574.61	$ 1,572.93	$ 1,207.43	$ 969.42	$ 7,251.02
206	% Change	105.78%	105.78%	145.05%	166.83%	122.06%	89.72%	122.49%

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

	Winter 2020-21	Winter 2021-22
Customer Charge	$ 15.50	$ 15.39
First 100 Therms	$ 0.5678	$ 0.5632
Excess 100 Therms	$ 0.5678	$ 0.5632
LDAC	$ 0.0589	$ 0.1444
COG	$ 0.5100	$ 1.1339
Total Adjust	$ 0.5689	$ 1.2783

				Total		Base Rate		COG		LDAC	
		Winter 2020-21 COG @	Winter 2021-22 @	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.5689	$1.2783	$0.71	125%						
Cooking alone	5	$21.05	$24.60	$3.55	16.85%	$0.00	0%	$3.12	13%	$0.43	2.03%
	10	$26.71	$33.81	$7.09	26.56%	$0.00	0%	$6.24	18%	$0.86	3.20%
	20	$38.03	$52.22	$14.19	37.30%	$0.00	0%	$12.48	24%	$1.71	4.50%
Water Heating alone	30	$49.35	$70.64	$21.28	43.12%	$0.00	0%	$18.72	26%	$2.57	5.20%
	45	$66.34	$98.26	$31.92	48.12%	$0.00	0%	$28.07	29%	$3.85	5.80%
	50	$72.00	$107.47	$35.47	49.27%	$0.00	0%	$31.19	29%	$4.28	5.94%
Heating Alone	80	$100.30	$153.50	$53.20	53.04%	$0.00	0%	$46.79	30%	$6.41	6.39%
	125	$165.96	$260.31	$94.35	56.85%	$0.00	0%	$82.97	32%	$11.37	6.85%
	150	$185.21	$291.62	$106.41	57.45%	$0.00	0%	$93.58	32%	$12.83	6.93%
	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.**
2 **d/b/a Liberty**
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**
5
6
7

Line		WINTER 2020-2021 ACTUAL RESULTS (6 months actual)			WINTER 2021-2022 (6 months Proposed)		
11	Therm Sales (COG)	124,069,459			87,443,741		
12-14		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
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

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

				Column A	Column B	Column C	Column D	Column E	Column F
				Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg			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	**42.607%**		3,719	69,396
14	LLF Total			75,211	82,510	**48.083%**		2,626	79,885
15	HLF Total			14,903	15,977	**9.310%**		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							**100.0%**	**100.0%**
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	**42.607%**	615,228	4,506	$11.3770			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.607%**	6,348,623	46,502	$11.3770			
48	Storage	Line 40 * Line 13 Col C	**42.607%**	1,755,962	11,979	$12.2156			
49	Peaking	Line 41 * Line 13 Col C	**42.607%**	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

51								
52								**Ratios for COG**
53	C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
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		**57.393%**		14,109,870	98,488	$11.9388	**1.0000**
59								
60								
61	LLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
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		**48.3884%**		11,896,104	82,895	$11.9590	**1.0017**
67			38.291%		84%			(Line 66 / Line 58)
68								
69	HLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
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		**9.0047%**		2,213,767	15,593	$11.8310	**0.9910**
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	**LLF C&I**	**HLF C&I**	
86								
87	Pipeline				69.77%	**68.68%**	**75.52%**	
88	Storage				16.38%	**16.97%**	**13.26%**	
89	Peaking				13.85%	**14.35%**	**11.22%**	
90	Total				100.00%	**100.00%**	**100.00%**	
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.** Updated Schedule 10A
2 **d/b/a Liberty** Page 3 of 3
3 **2021 - 2022 Winter Cost of Gas Filing**
4 **Correction Factor Calculation**

Ln		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	1,993,710	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

Ln			
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, ln 74
29	High Winter Use	32,672,890	
30	Winter Ratio for High Winter Use	**1.0017**	Schedule 10A p 2, ln 66
31			
32	Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))	
33	Correction Factor =	$\boxed{\textbf{100.0099\%}}$	

36 **Allocation Calculation for Miscellaneous Overhead**

Ln		Period	Volume	Source
38	Projected Winter Sales Volume	11/1/21- 4/30/22	91,676,680	Sch.10B, ln 23
39	Projected Annual Sales Volume	11/1/21 - 10/31/22	115,042,810	Sch.10B, ln 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**
4
5

6 **Dry Therms**

								Subtotal							Subtotal	
7	**Firm Sales**															
8		**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**PK 21-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**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
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	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
33																
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**
35																
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**
5 **Updated Schedule 11A**
6 **Page 1 of 1**
7 **Volumes (Therms)** **Normal Year**
8
9 **For the Months of May 21 - October 21**

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov - Apr
13	Pipeline Gas:							
14	Dawn Supply	876,821	926,304	927,705	840,605	911,138	750,758	5,233,331
15	Niagara Supply	691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
16	TGP Supply (Gulf)	4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346	17,283,547
17	Dracut Supply 1 - Baseload	-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
18	Dracut Supply 2 - Swing	1,775,785	5,569,137	771,324	-	969,754	79,714	9,165,713
19	Dracut Supply 3 - Swing	-	596,455	290,490	-	1,484	-	888,430
20	Constellation Combo	89,306	231,576	1,424,042	1,188,519	1,411,967	-	4,345,410
21	LNG Truck	20,666	21,875	51,371	291,824	362,081	-	747,817
22	Propane Truck	-	-	-	695,072	-	-	695,072
23	PNGTS	219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
24	Portland Natural Gas	1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355	6,284,969
25	TGP Supply (Z4)	1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071	14,753,578
26	Subtotal Pipeline Volumes	11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749	75,575,334
27		11,146,258	17,666,150	15,671,258	12,655,305	10,660,614	8,575,749	76,375,334
28	Storage Gas:							
29	TGP Storage	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
30								
31	Produced Gas:							
32	LNG Vapor	21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
33	Propane	-	-	244,014	574,010	-	-	818,023
34	Subtotal Produced Gas	21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
35								
36	Less - Gas Refills:							
37	LNG Truck	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)		(747,817)
38	Propane	-	-	-	(695,072)	-	-	(695,072)
39	TGP Storage Refill	(1,750,690)	-	-	-	-	(961,638)	(2,712,328)
40	Subtotal Refills	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
41								
42	Total Sendout Volumes	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211	94,216,591
43								

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** — **Updated Schedule 11B**
45 **Page 1 of 1**
46
47 **Volumes (Therms)** — **Design Year**
48
49 **For the Months of May 21 - October 21**
50

51								Peak
52		**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Nov - Apr**
53	Pipeline Gas:							
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:							0
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

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Updated Schedule 11C**
d/b/a Liberty **Page 1 of 1**
Peak 2021 - 2022 Winter Cost of Gas Filing
Capacity Utilization
Volumes (Therms)

	Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
Pipeline Gas:								
Dawn Supply	5,233,331	4,000	7,240,000	72%	5,257,245	4,000	7,240,000	73%
Niagara Supply	4,212,753	3,122	5,650,820	75%	4,212,753	3,122	5,650,820	75%
TGP Supply (Gulf + Z4)	32,037,125	21,596	39,088,760	82%	32,412,730	21,596	39,088,760	83%
Dracut Supply 1 & 2 & 3	20,704,916	90,000	162,900,000	13%	30,503,096	90,000	162,900,000	19%
LNG Truck	747,817	-	-	-	753,030	-	-	-
Propane Truck	695,072	-	-	-	695,779	-	-	-
PNGTS	1,313,941	1,000	1,810,000	73%	1,313,941	1,000	1,810,000	73%
Portland Natural Gas	6,284,969	5,000	9,050,000	69%	6,392,220	5,000	9,050,000	71%
Constellation Vapor	4,345,410	7,000	6,300,000	69%	4,348,701	7,000	6,300,000	69%
Subtotal Pipeline Volumes	75,575,334				85,889,495			
Storage Gas:								
TGP Storage	19,999,699		25,791,710	78%	19,999,699		25,791,710	78%
Produced Gas:								
LNG Vapor	1,978,752				1,978,752			
Propane	818,023.3				818,023			
Subtotal Produced Gas	2,796,775				2,796,775			
Less - Gas Refills:								
LNG Truck	(747,817)				(747,817)			
Propane	(695,072)				(695,072)			
TGP Storage Refill	(2,712,328)				(2,712,328)			
Subtotal Refills	(4,155,217)				(4,155,217)			
Total Sendout Volumes	94,216,591				104,530,752			

Liberty Utilities (EnergyNorth Natural Gas) Corp. | **Updated Schedule 11D**
d/b/a Liberty | **Page 1 of 1**
Peak 2021 - 2022 Winter Cost of Gas Filing

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

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

Requirements

Firm Sales	1,283,926
Interruptible Sales	0
Firm Transportation	432,092
Interruptible Transportation	0
Total Requirements	1,716,018

Resources

Purchased Pipeline Gas	1,197,180
Underground Storage Gas	281,150
Propane Air Production	41,688
LNG Produced Gas	126,000
Third-Party Supply	70,000
Total Resources	1,716,018

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.

Preparation of this report was supervised by:

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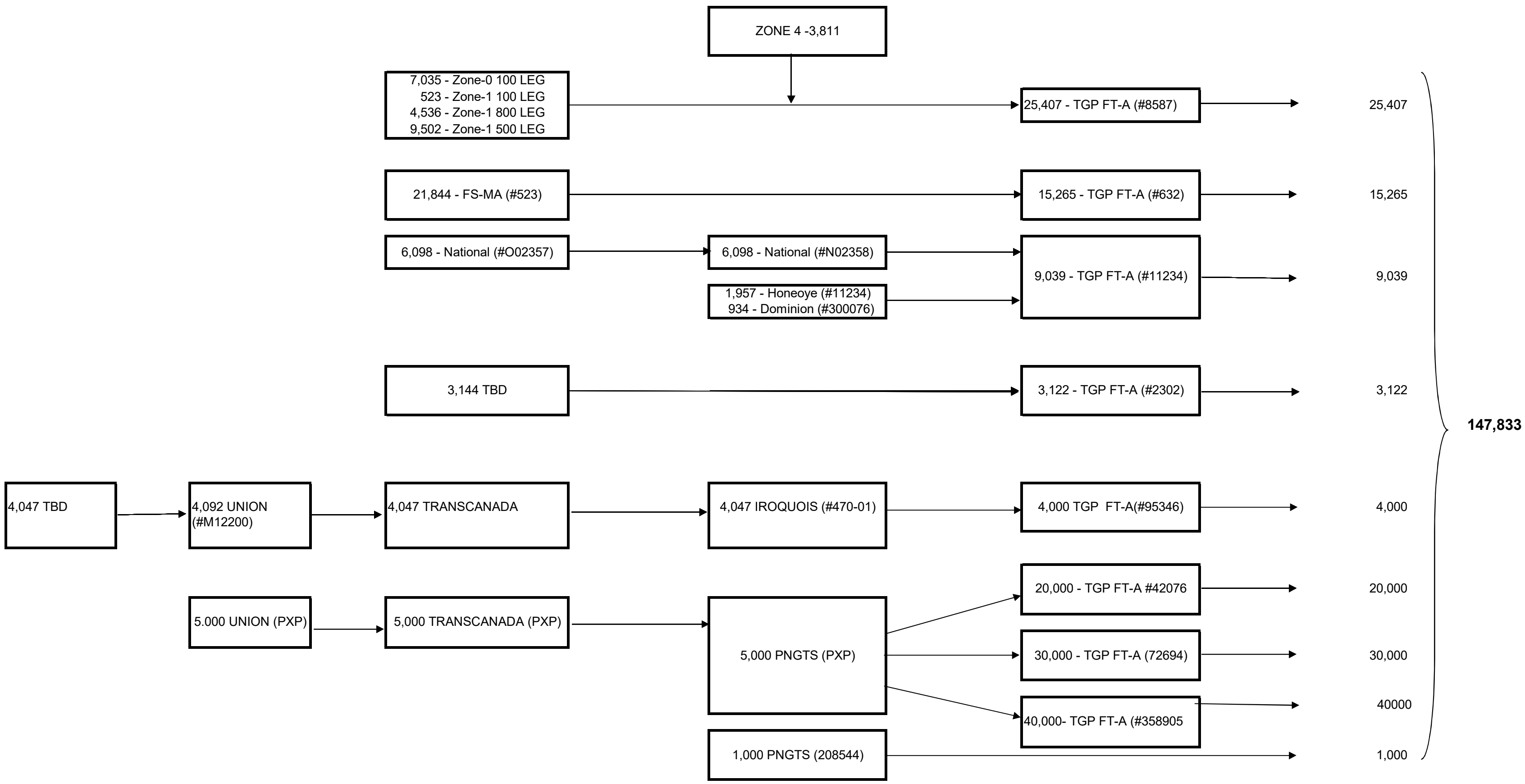
Deborah Gilbertson
Sr. Manager, Energy Procurement

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

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



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

Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
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	O02358	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.

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

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

July 2020 - June 2021 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	18,356,822	40.75%	78.44%
G-42	15,353,253	34.08%	45.73%
G-43	3,841,684	8.53%	31.47%
G-51	2,891,430	6.42%	76.18%
G-52	3,253,957	7.22%	38.33%
G-53	1,018,263	2.26%	10.14%
G-54	330,714	0.73%	1.92%
Total C/I	45,046,124	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,045,712	7.92%	21.56%
G-42	18,223,357	28.60%	54.27%
G-43	8,366,118	13.13%	68.53%
G-51	903,966	1.42%	23.82%
G-52	5,236,072	8.22%	61.67%
G-53	9,026,718	14.17%	89.86%
G-54	16,915,516	26.55%	98.08%
Total C/I	63,717,458	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	23,402,533	21.52%	100.00%
G-42	33,576,610	30.87%	100.00%
G-43	12,207,803	11.22%	100.00%
G-51	3,795,396	3.49%	100.00%
G-52	8,490,028	7.81%	100.00%
G-53	10,044,981	9.24%	100.00%
G-54	17,246,230	15.86%	100.00%
Total C/I	108,763,581	100.00%	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Updated Schedule 14
Peak 2021 - 2022 Winter Cost of Gas Filing Page 1 of 1

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

	Off-Peak	**Peak**	**Total**	
	May 20 - Oct 20	**Nov 20-Apr 21**	**May 20 - Apr 21**	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	18,824,010	84,277,810	103,101,820	
All Others	132,500	1,914,540	2,047,040	
	18,956,510	86,192,350	105,148,860	
				Ratio
Total Winter Supplies				86,192,350
Total Pipeline Deliveries				103,101,820
Ratio Winter Supplies to Pipeline Supplies				0.836

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

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

C&I Sales Normalized (Therms)	**Jul-20**	**Aug-20**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	174,747	138,891	313,637	18,356,822	1.71%
G-42	195,842	150,099	345,941	15,353,253	2.25%
G-43	52,926	47,293	100,219	3,841,684	2.61%
G-51	155,287	140,064	295,352	2,891,430	10.21%
G-52	183,712	169,419	353,131	3,253,957	10.85%
G-53	84,472	58,190	142,662	1,018,263	14.01%
G-54	15,457	18,585	34,042	330,714	10.29%
Total C/I	862,442	722,541	1,584,983	45,046,124	3.52%

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

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

Underground Storage Gas

Ln	Description	Reference	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
9	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
11	Injections (MMBtu)	Sch 11A ln 39 /10	234,130	253,870	260,938	260,000	260,000	128,220	128,220	-	-	-	-	96,164	1,621,542
13	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	
15	Storage Sale/Adjustments		(3,346)	(4,221)	(4,378)	-	-	-	-	-	-	-	-	-	(11,945)
17	Withdrawals (MMBtu)	Sch 11A ln 29 /10	-	-	-	-	-	-	(275,298)	(85,012)	(550,352)	(489,051)	(476,047)	(124,208)	(1,999,970)
19	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
22	Beginning Balance		$ 921,816	$ 1,463,053	$ 2,088,182	$ 2,854,560	$ 3,915,098	$ 4,975,636	$ 5,498,645	$ 5,332,361	$ 5,073,441	$ 3,397,231	$ 1,907,725	$ 457,826	$ 921,816
24	Injections	ln 11 * ln 36	$ 534,796	$ 619,603	$ 760,761	$ 1,060,538	$ 1,060,538	$ 523,008	$ 672,193	$ -	$ -	$ -	$ -	$ 370,519	$ 5,601,957
26	Subtotal		$ 1,456,612	$ 2,082,656	$ 2,848,943	$ 3,915,098	$ 4,975,636	$ 5,498,645	$ 6,170,838	$ 5,332,361	$ 5,073,441	$ 3,397,231	$ 1,907,725	$ 828,345	
28	Storage Sale/Adjustments		$ 6,441	$ 5,526	$ 5,618			$ -							
30	Withdrawals	ln 17 * ln 34	-	-	-	-	-	-	(838,477)	(258,921)	(1,676,210)	(1,489,505)	(1,449,899)	(417,423)	$ (6,130,435)
32	Ending Balance		$ 1,463,053	$ 2,088,182	$ 2,854,560	$ 3,915,098	$ 4,975,636	$ 5,498,645	$ 5,332,361	$ 5,073,441	$ 3,397,231	$ 1,907,725	$ 457,826	$ 410,922	$ 393,337
34	Average Rate For Withdrawals	ln 22 /ln 9	$ 1.9505	$ 2.0883	$ 2.2719	$ 2.5934	$ 2.8117	$ 2.8973	$ 3.0457	$ 3.0457	$ 3.0457	$ 3.0457	$ 3.0457	$ 3.3607	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$ 2.2842	$ 2.4406	$ 2.9155	$ 4.0790	$ 4.0790	$ 4.0790	$ 5.2425	$ 5.5130	$ 5.6315	$ 5.5075	$ 5.2565	$ 3.8530	

Ln	For Informational Purposes	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
39	Summer Hedge Contracts - Vols Dth	-	-	-	-	-	-	-
40	Average Hedge Price	$ -	$ -	$ -	$ -	$ -	$ -	
41	NYMEX	$ 5.5900	$ 5.7530	$ 5.8540	$ 5.7500	$ 5.4290	$ 4.0980	
43	Hedged Volumes at Hedged Price	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Hedge (Savings)/Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ln	Description	Reference	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
47	Month Dollar Average	ln (22 + ln 32) /2	$ 3,384,829	$ 4,445,367	$ 5,237,141	$ 5,415,503	$ 5,202,901	$ 4,235,336	$ 2,652,478	$ 1,182,776	$ 434,374
49	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%
51	Inventory Finance Charge	ln 47 * ln 49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	Financial Expenses		-	-	-	-	-	-	-	-	-
53	Total Inventory Finance Charges		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ln	Description	Reference	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
41	**Liquid Propane Gas (LPG)**														
42			May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
43			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
44	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
46	Injections	Sch 11A ln 38 /10	-	-	-	-	-	-	-	-	-	69,507	-	-	69,507
48	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	
50	Withdrawals	Sch 11A ln 33 /10	-	-	-	-	-	-	-	-	(24,401)	(57,401)	-	-	(81,802)
52	Adjustment for change in temperature		(1,113)	192	(435)	-	-	-	-	-	-	-	-	-	(1,356)
53	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
54	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
57	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
59	Injections	ln 46 * ln 69	-	-	-	-	-	-	-	-	-	834,086	-	-	834,086
61	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	
63	Withdrawals/ Adjust	ln 52 * ln 67	(11,942)	2,060	(4,667)	-	-	-	-	-	(261,807)	(658,652)	-	-	(935,008)
65	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
67	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	
69	Propane Rate for Injections	Actual or Sch. 6, ln 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	
72	Month Dollar Average	ln (57 + ln 65) /2				$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 656,576	$ 613,390	$ 701,107	$ 701,107	
74	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%	
76	Inventory Finance Charge	ln 72 * ln 74				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
79	**Liquid Natural Gas (LNG)**		May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
80			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
81	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
83	Injections	Sch 11A ln 37 /10	809	781	1,468	781	781	781	2,067	2,188	5,137	29,182	36,208	-	80,183
85	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)	
87	Withdrawals	Sch 11A ln 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)
89	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)
92	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
94	Injections	ln 83 * ln 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
96	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)	
98	Withdrawals	ln 87 * ln 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)
100	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)
102	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	
104	LNG Rate for Injections	Actual or Sch. 6, ln 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	
107	Month Dollar Average	ln (92 + ln 100) /2				$ 45,014	$ 40,047	$ 34,453	$ 31,192	$ (109,404)	$ (422,246)	$ (731,073)	$ (840,669)	$ (821,327)	
109	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%	
111	Inventory Finance Charge	ln 107 * ln 109				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
114	Total Fuel Financing	lns 53 + 76 + 111				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty — Updated Schedule 17
Peak 2021 - 2022 Winter Cost of Gas Filing — Page 1 of 1

Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	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	5,224,390	0.0002	851
Total	**42,583,790**		**$ 6,938**

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 — Updated Schedule 19

Local Delivery Adjustment Charge (LDAC) increase due to Rate Case Expense and Recoupment — RCE

For LDAC effective November 1, 2021 - October 31, 2022 —

1	Rate Case Exepense	
2	Prior Period Balance	($11,949)
3	Expenses thru June 30, 2021	$785,177
4	Balance at June 30, 2021	$773,228
5	Less: Accrual Balance	($26,000)
6	Adjusted Rate Case Expense	$747,228
7		
8	Recoupment	
9	Distribution Recoupment from Docket No. DG 20-105	($568,780)
10	Indirect Costs Recoupment from Docket No. DG 20-105	$1,900,000
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	($7,864)
20		
21	Total Estimated Remaining Recovery As of November 1, 2021	$2,187,779
22		
23	Estimated November 2021 - October 2022 Interest	$26,727
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)
1	**FOR THE MONTH OF:**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**30**	**31**	**31**	**28**
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
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)
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
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
16									
17	Interest Rate	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
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**

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Total**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	
3	Beginning Balance	$ 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	-	-	-	-	-	-	-	-	-
6										
7	Add: Recoupment	-	-	-	-	-	-	-	-	-
8										
9	Less: Collected Revenue	(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	$ 739,995	$ 568,704	$ 453,953	$ 379,192	$ 310,992	$ 240,282	$ 151,201	$ (202)	**$ 8,782,201**
14										
15	Month's Average Balance	$ 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%	
18										
19	Interest Applied	$ 2,413	$ 1,810	$ 1,368	$ 1,152	$ 954	$ 738	$ 541	$ 202	**26,727**
20										
21	Ending Balance	**$ 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 Uitilities
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	$1,522,705
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	($2,012,414)
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	$903,659
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

RESIDENTIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
FOR THE MONTH OF:	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**
DAYS IN MONTH	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
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)**

COMMERCIAL & INDUSTRIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
FOR THE MONTH OF:	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**
DAYS IN MONTH	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
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)**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
September 2020 through August 2021
Revenue Decoupling Activity by Sector

	RESIDENTIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
1	FOR THE MONTH OF:	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21
2	DAYS IN MONTH	30	31	30	31	31	28	31	30	31	30	31	31
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**

	COMMERCIAL & INDUSTRIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
18	FOR THE MONTH OF:	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21
19	DAYS IN MONTH	30	31	30	31	31	28	31	30	31	30	31	31
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**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Revenue Decoupling
Adjustments to Residential prior year filings for low income customer treatment

2019-2020 Filing

		Filing	Adjusted (1)	Difference
	Residential			
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)	(4,085,152.93)	(2,152,929.54)	$ 1,932,224
	Commercial			
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)	(2,931,638.28)	(2,931,638.28)	$ -
7.	**TOTAL Revenue Deficiency / (Excess)**	**(7,016,791.21)**	**(5,084,567.82)**	**$ 1,932,224**

2020-2021 Filing

		Filing	Adjusted (1)	Difference
	Residential			
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)	(3,150,743.35)	(1,058,138.97)	$ 2,092,605
	Commercial			
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)	(1,815,203.44)	(1,815,203.44)	$ -
14.	**TOTAL Revenue Deficiency / (Excess)**	**(4,965,946.79)**	**(2,873,342.41)**	**$ 2,092,605**

(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

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Actual DSM Expenditures Low-Income	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Monthly Federal Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Residential Therm Sales	Residential Therm Sales	# of Days
May 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
Total Charges	**$**	**5,652,830**
Projected Therm Sales		**65,649,919**
Residential Rate		**$0.0861**
Total Charges with Interest	**$**	**5,652,830**
Projected Therm Sales		**65,649,919**
Residential Rate		**$0.0861**

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%
Total Therms	100%	**182,899,057**	**182,899,057**	100%
		Budget **2021**	Budget **2022**	
Low-Income Program Budget		**$ 1,523,570**	**$ 1,627,400**	
Other Refund		-	-	
Total Shared Budget		**$ 1,523,570**	**$ 1,627,400**	
Residential Program Budget		**$ 3,926,326**	**$ 4,059,085**	
Residential Performance Incentive		**$ 299,744**	**$ 312,757**	
Total Residential Program Budget		**$ 4,226,070**	**$ 4,371,842**	
Commercial/Industrial Program Budget		**$ 3,512,260**	**$ 3,886,433**	
Commercial/Industrial Program Incentive		**$ 193,174**	**$ 213,754**	
Total Commercial/Industrial Program Budget		**$ 3,705,434**	**$ 4,100,187**	
Total Program Budget		**$ 9,455,074**	**$ 10,099,429**	
Shared Expenses Allocation to Residential		$ 546,871	$ 577,544	
Shared Expenses Allocation to C&I		976,699	1,043,260	
Total Allocated Shared Expenses		**$ 1,523,570**	**$ 1,620,804**	
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	
Total Budget		**$ 9,455,074**	**$ 10,092,833**	

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
Total Budget	**$ 9,455,074**	**$ 10,092,833**

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

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures C&I	Actual DSM Expenditures Low-Income	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Fed Reserve Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Commercial/ Industrial Therm Sales	Actual Commercial/ Industrial Therm Sales	# of Days
May 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
Total Charges	**$4,775,998**
Projected Therm Sales	**117,179,952**
C&I Rate	$0.0408
Total Charges with Interest	**$4,780,942**
Projected Therm Sales	**117,179,952**
C&I Rate	**$0.0408**

Liberty Utilities (EnergyNorth 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

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Actual DSM Expenditures C&I	Actual DSM Expenditures Low-Income	Actual DSM Expenditures Total	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Actual Therm Sales	# of Days
May 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		(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		(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		(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		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		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		(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		(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		(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		(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		(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		(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		(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		(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		(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		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		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		(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		(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
Total Charges		**$10,428,828**

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

Gas Assistance Program

Ln					
1	**Distribution**	**Customer Charge**	**Block**	**Total**	
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	**COG**	**ENNG**	**Keene**	**Total**	
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	**Total Gas Assistance Program Charge**			**$ 0.0156**	

(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)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
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 2333
Quarterly Report
Gas Assistance Program (GAP)
2020-21 Discounted 45%

	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/ Projected Total To Date (1)	Summary Original Projection (2)	Summary Variance
Customer Count															
	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected			
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
GAP Recoveries															
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	
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		$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
Program Costs															
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
Avg Monthly Residential Customer	$ 66.50	$ 108.64	$ 146.69	$ 160.62	$ 151.71	$ 124.41	$ 63.52	$ 41.86	$ 30.56	$ 28.68	$ 28.68	$ 35.27	$987.15	$1,907.80	$920.65
v	$ 48.53	$ 81.61	$ 115.53	$ 130.93	$ 121.07	$ 93.93	$ 63.52	$ 41.86	$ 30.56	$ 28.68	$ 28.68	$ 35.27	$820.18	$228.58	($591.61)
Avg Monthly GAP Customer Disco	$17.97	$27.03	$31.17	$29.69	$30.64	$30.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$166.97	$1,679.22	$1,512.25
v	27.02%	24.88%	21.25%	18.49%	20.19%	24.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	16.91%	88.02%	
Gross Monthly Revenues	$10,019,053	$18,375,801	$28,990,263	$20,353,998	$18,671,873	$11,875,246	$7,698,494	$5,238,262	$4,997,762	$6,467,910	$5,113,368	$8,930,712	$146,732,741	$161,677,049	$14,944,308
ot	5.60%	1.37%	0.99%	1.43%	1.47%	1.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.28%	1.34%	

(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	$139,028	
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	$0.0155	per therm
Total Environmental Surcharge	$0.0155	

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)[1], 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.

[1] 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.

- 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.

- 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 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.

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.

- 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.

- 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.

- 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.**

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 NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

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

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

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

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.

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)[1] 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.

[1] 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.

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

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

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments. In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage. In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence. NHDES approved the ravine sign language in April 2002.

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

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

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

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

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

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

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

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

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

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

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

- 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**

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.

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 owning no indemnity.

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

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)[1], another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials

[1] 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.

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.

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.

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

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

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)[1] 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.

[1] 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.

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

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.

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 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.

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 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.

<u>Concord Pond</u>: 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

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

2021 SUMMARY BY SITE

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

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

REDACTED
Schedule 20.2

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	[redacted]										(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	[redacted]										(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	[redacted]										(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	[redacted]										(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	[redacted]										(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
	[redacted]										

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

REDACTED
Schedule 20.2

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
	[redacted]										

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

REDACTED
Schedule 20.2

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	[redacted]										(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	[redacted]										(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	[redacted]										(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
	[redacted]										

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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 REMEDIATION 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
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**5,645.56**	**5,645.56**	**0.00**	**0.00**	**5,645.56**

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0431

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

REDACTED
Schedule 20.2

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	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	[redacted]										(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	[redacted]										(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	[redacted]										(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	[redacted]										(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	[redacted]										(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	[redacted]										

THIS PAGE HAS BEEN REDACTED

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUB-TOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	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
	Total Pool Activity		**0.00**	**12,243.50**	**0.00**	**0.00**	**2,657.60**	**14,901.10**			**14,901.10**

177

0433

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

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

Concord Pond

		(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	DEF056 (7/20 - 6/21) ool #22	s total
1	1 Remediation costs (i.o. 500061)	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	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
																	0
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	Cash recoveries (i.o. 50000)	- 5,985															- 5,985
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	Transfer Credit from Gas Restructuring																
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																	
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																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	-5 ,889															-5 ,889
16	Act November 1998 - October 1999	-538,1 3															-538,1 3
17	Act November 1999 - October 2000	-760,871															-760,871
18	Act November 2000 - October 2001	-6 0,539															-6 0,539
19	Act November 2001 - October 2002	-625,11															-625,11
20	Act November 2002 - October 2003	-607,87															-607,87
21	Act November 2003 - October 200	-305,907															-305,907
22	Act November 200 - October 2005	-85,078															-85,078
23	Act November 2005- October 2006	-13,750															-13,750
2	Act November 2006- October 2007	-1 ,091	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1 ,091
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Act November 2012- October 2013	0				-5,002	-5,002										-10,003
27	Act November 2013- October 201	0				-12,7 9	-12,7 9										-25, 97
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				- , 23											- , 23
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				-32,310											-32,310
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				-28, 8											-28, 8
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				-2,1 3	-2,1 3										- ,286
32	Act Nov 2013-Oct 201 Base Rate Rev	0															0
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															0
3	AES co lections	-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	Gas Street overcollection	-23,511															-23,511
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																	
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
0																	
1																	
2	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
3																	
	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
5																	
6	Surcharge calculation																
7	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
8	remaining life	168	72	8	8	8	12	12	12	12	2	36	8	60	72	8	
9	one year	8	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
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																	
52	Required annual increase in rates:																
53	smal er 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
5																	
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	182,899,057	182,899,057
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	$0.0001	$0.0000	$0.0001	$0.0002	$0.0006

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar 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

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)	
		ool #1 - #6	ool #7	ool #8	ool #9	ool #10	ool #11	ool #12	pool #13	pool #14	pool #15	pool #16	pool #17	pool #18	pool #18	pool #19	s total
			Incl. Aud t Corr	Incl. Audit Corr													
1	1 Remediation costs (i.o. 500061)	0							[redacted]								0
2	Remediation costs (i.o. 500005)	9,670, 88	28,225	607,876	262,678	210,532	269,281	6 2,986	[redacted]								2 ,751,360
3	A Subtotal - remediation costs	9,670, 88	28,225	607,876	262,678	210,532	269,281	6 2,986	[redacted]								2 ,751,360
5	Cash recover es (i.o. 500061)	0	0	0					[redacted]								0
6	Cash recover es (i.o. 50000)	0	0	0					[redacted]								0
7	Recovery costs (i.o. 50000)	11,6 3	21,729	0	0				[redacted]								33,372
8	Transfer Credit from Gas Restructuring	0	0	0					[redacted]								0
9	B Subtotal - net recoveries	11,6 3	21,729	0	0	0	0	0	[redacted]								33,372
10									[redacted]								
11	A-B Total net expenses to recover	9,682,131	9,95	607,876	262,678	210,532	269,281	6 2,986	[redacted]								2 ,78 ,732
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
16	Act November 1998 - October 1999	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
17	Act November 1999 - October 2000	-151,933	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-151,933
18	Act November 2000 - October 2001	-696,237	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-696,237
19	Act November 2001 - October 2002	-796,71	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-796,71
20	Act November 2002 - October 2003	-805, 3	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-805, 3
21	Act November 2003 - October 200	-699,215															-699,215
22	Act November 200 - October 2005	-652,26															-652,26
23	Act November 2005- October 2006	-691,159	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-691,159
2	Act November 2006- October 2007	-958,171	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-958,171
25	Act November 2007- October 2008	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
26	Act November 2012- October 2013	0					-20,006										-20,006
27	Act November 2013- October 201	0					-25, 97	-76, 91									-101,988
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				- ,296											- ,296
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				-31,38											-31,38
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				-27,632											-27,632
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-1 ,208										-1 ,208
32	Act Nov 2013-Oct 201 Base Rate Rev	0					-28, 33	-28, 33	(28,433)								-85,298
33	Act Nov 201 -Oct 2015 Base Rate Rev	0					-21,639	-21,639	(21,639)	(21,639)	-	-	-	-	-	-	-86,55
3	AES co lections	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
35	Gas Street overcollection	0															0
36	Pr or Period Pool under/overcollect on	2,395,362	,2 2, 38	0	0	0	-87,311	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
0																	
1																	
2	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	[redacted]								18,962,237
3									[redacted]								
	E Allocat on of Lit gated Recovery	0	- ,692,393	-607,876	-262,678	-23 ,530	0	0	[redacted]								-5,797, 76
5									[redacted]								
6	Surcharge calculation								[redacted]								
7	Unrecovered costs (D E)	0	0	0	0	0	0	0	[redacted]								2,127,600
8	remaining life	1	72	8	8	8	12	12	[redacted]								
9	one year	36	12	12	12	12	12	12	[redacted]								
50	F amortization		0	0	0	0	0	0	[redacted]								1,588,357
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	[redacted]								1,588,357
5																	
55	forecas ed therm 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																	
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]								$0.0087
											5 68.8086	1 333.37571	862.888571	2199.96	3989.371 29	2128.728571	

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar 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

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)	
		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	s total
			Incl. Audit Corr														
1	1 Remediation costs (i.o. 500061)	3,762,097	,387,6 5	312,185	369,037	372,237	507,622	82,113	92,900	116, 96	71,011	5 ,333	70,725	182,093	312, 33	, 76	11,137, 03
2	Remediation costs (i.o. 500005)	825,092															825,092
3	A Subtotal - remediation costs	,587,189	,387,6 5	312,185	369,037	372,237	507,622	82,113	92,900	116, 96	71,011	5 ,333	70,725	182,093	312, 33	, 76	11,962, 95
5	Cash recover es (i.o. 500061)	-765,892	-1,127, 36		- 0,359	-23 ,6 8	-65,32	-270,732	-31,690	- 1,057	- 8,322	-3,810	-12 ,681	-1 ,07	-157, 01	-39,395	-3,09 ,822
6	Cash recover es (i.o. 50000)	0															0
7	Recovery costs (i.o. 50000)	1,2 ,872	0														1,2 ,872
8	Transfer Credit from Gas Restructuring	0	0														0
9	B Subtotal - net recoveries	78,979	-1,127, 36	0	- 0,359	-23 ,6 8	-65,32	-270,732	-31,690	- 1,057	- 8,322	-3,810	-12 ,681	-1 ,07	-157, 01	-39,395	-1,8 9,950
10																	
11	A-B Total net expenses to recover	5,066,169	3,260,209	312,185	328,678	137,589	2,298	-188,619	61,210	75, 0	22,690	50,523	3 6,0 3	38,019	155,032	5,080	10,112,5 5
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0															0
16	Act November 1998 - October 1999	0															0
17	Act November 1999 - October 2000	0															0
18	Act November 2000 - October 2001	0															0
19	Act November 2001 - October 2002	-73,5 3															-73,5 3
20	Act November 2002 - October 2003	-75,98															-75,98
21	Act November 2003 - October 200	-138,576															-138,576
22	Act November 200 - October 2005	-326,132	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-326,132
23	Act November 2005- October 2006	-563,732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-563,732
2	Act November 2006- October 2007	-662,265	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-662,265
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Act November 2012- October 2013	0					- 0,012										- 0,012
27	Act November 2013- October 201	0					-50,99										-50,99
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				0											0
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				0											0
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				0											0
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-23,337										-23,337
32	Act Nov 2013-Oct 201 Base Rate Rev	0															0
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															0
3	AES co lections	0															0
35	Gas Street overcollection	0															0
36	Pr or Period Pool under/overcollect on	7,525,691	3,302,330	0	0	0	0	0	0	0	0	0	0	0	0	0	
37																	
38																	
39	C Surcharge Subtotal	5,685, 59	3,302,330	0	0	0	-11 ,3 3	0	0	0	0	0	0	0	0	0	-1,95 ,576
0																	
1																	
2	D Net balance to be recovered (A-B C)	10,751,628	6,562,539	312,185	328,678	137,589	327,955	-188,619	61,210	75, 0	22,690	50,523	3 6,0 3	38,019	155,032	5,080	8,157,969
3		0															
	E Allocat on of Lit gated Recovery	0	-6,562,539	-312,185	-328,678	-9 ,3 0	0	0	0	0	0	0	0	0	0	0	-7,297,7 2
5		0															
6	Surcharge calculation	0															
7	Unrecovered costs (D E)	0	0	0	0	0	0	0	0	10,777	6, 83	21,653	197,739	27,156	132,885	5,080	01,773
8	remaining life	168	70	8	8	12	12	12	12	12	2	36	8	60	72	8	
9	one year	8	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	10,777	3,2 1	7,218	9, 35	5, 31	22,1 7	726	
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	10,777	3,2 1	7,218	9, 35	5, 31	22,1 7	726	98,975
5		0															
55	forecas ed therm sales	1,28 , 2 ,318	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																	
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003	$0 0000	$0.0001	$0.0000	$0.0005

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar 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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
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		Nashua															
							Corrected per 2/08 Audit									DEF054	
		(9/00 - 9/07) ool #1 - #7	(9/07 - 9/08) ool #8	(9/08 - 9/09) ool #9	(9/09 - 9/10) ool #10	(9/10 - 9/11) ool #11	(9/11 - 9/12) ool #12	(9/12 - 6/13) ool #13	(7/13 - 6/1) ool #1	(7/1 - 6/15) ool #15	(7/15 - 6/16) ool #16	(7/16 - 6/17) ool #17	(7/17 - 6/18) ool #18	(7/18 - 6/19) ool #19	(7/19 - 6/20) ool #20	(7/20 - 6/21) ool #21	s total
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	100,3 2	61, 78	128,071	39 533	96,86	1,88 ,513
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	100,3 2	61, 78	128,071	39 533	96,86	3,656,080
5	Cash recover es (i.o. 500061)	-22,732	-10, 1	-62,2 6	-63,753	-31,767	-2,990	-199,336	-27, 7	- 0,699	- 3,69	-15,029	- 5,955	- 6,103	-28,062	-35,8 8	-676,075
6	Cash recover es (i.o. 50000)	0															0
7	Recovery costs (i.o. 50000)	18,388	0	0													18,388
8	Transfer Credit from Gas Restructuring	0	0	0													0
9	B Subtotal - net recoveries	- ,3	-10, 1	-62,2 6	-63,753	-31,767	-2,990	-199,336	-27, 7	- 0,699	- 3,69	-15,029	- 5,955	- 6,103	-28,062	-35,8 8	-657,687
10																	0
11	A-B Total net expenses to recover	2,017,521	97,191	16,289	98,975	33,351	396, 11	-80,2 1	35,950	65,217	62, 35	85,31	15,523	81,969	11, 72	61,016	2,998,392
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0															0
16	Act November 1998 - October 1999	0															0
17	Act November 1999 - October 2000	0															0
18	Act November 2000 - October 2001	0															0
19	Act November 2001 - October 2002	-183,857															-183,857
20	Act November 2002 - October 2003	-2 3,150															-2 3,150
21	Act November 2003 - October 200	-2 7,639															-2 7,639
22	Act November 200 - October 2005	-2 1,05															-2 1,05
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	Act November 2006- October 2007	-281,815	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-281,815
25	Act November 2007- October 2008	0															0
26	Act November 2012- October 2013	0					- 0,012										- 0,012
27	Act November 2013- October 201	0					-38,2 6										-38,2 6
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				0											0
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				0											0
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				0											0
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-20,916										-20,916
32	Act Nov 2013-Oct 201 Base Rate Rev	0															0
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															0
3	AES co lections	0															0
35	Gas Street overcollection	0															0
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	
37																	
38																	
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																	
1																	
2	D Net balance to be recovered (A-B C)	3,731,617	830,669	16,289	98,975	33,351	302,853	-80,2 1	35,950	65,217	62, 35	85,31	15,523	81,969	11, 72	61,016	1, 26,713
3																	
	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
5																	
6	Surcharge calculation																
7	Unrecovered costs (D E)	0	0	0	0		0	0	0	9,317	17,838	36,563	8,870	58,5 9	9,833	61,016	201,987
8	remaining life	36	72	8	8	72	12	12	12	12	2	36	8	60	72	8	
9	one year	36	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	9,317	8,919	12,188	2,218	11,710	1,639	8,717	
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	9,317	8,919	12,188	2,218	11,710	1,639	8,717	5 ,707
5																	
55	forecas ed 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																	
####	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 s te, are not exclusive to a particu ar 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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Dover

DEF059

		(9/02 - 9/03) ool #1	(9/0 - 9/05) ool #2	(9/05 - 9/06) ool #3	(9/06 - 9/07) ool #	(9/07 - 9/08) ool #5	(9/08 - 9/09) ool #6	(9/09 - 9/10) ool #7	(9/10 - 9/11) ool #8	(9/11 - 9/12) ool #9	(9/12 - 6/13) ool #10	(7/13 - 6/1) ool #11	(7/1 - 6/15) ool #12	s total
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	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	Cash recover es (i.o. 500061)	0					0	0	0	0	0	0	0	0
6	Cash recover es (i.o. 50000)	0												0
7	Recovery costs (i.o. 50000)	0												0
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														
1	Surcharge revenue:													
15	Act June 1998 - October 1998	0												0
16	Act November 1998 - October 1999	0												0
17	Act November 1999 - October 2000	0												0
18	Act November 2000 - October 2001	0												0
19	Act November 2001 - October 2002	0												0
20	Act November 2002 - October 2003	0												0
21	Act November 2003 - October 200	-29,13												-29,13
22	Act November 200 - October 2005	-28 359												-28,359
23	Act November 2005- October 2006	-27, 99	0			0	0	0	0	0	0	0	0	-27, 99
2	Act November 2006- October 2007	-28,181	0	0	0	0	0	0	0	0	0	0	0	-28,181
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Act November 2012- October 2013													0
27	Act November 2013- October 201													0
28	Act Nov 2009-Oct 2010 Base Rate Rev													0
29	Act Nov 2010-Oct 2011 Base Rate Rev													0
30	Act Nov 2011-Oct 2012 Base Rate Rev													0
31	Act Nov 2012-Oct 2013 Base Rate Rev													0
32	Act Nov 2013-Oct 201 Base Rate Rev													0
33	Act Nov 201 -Oct 2015 Base Rate Rev													0
3	AES co lections													0
35	Gas Street overcollection													0
36	Pr or Period Pool under/overcollect on		67,892	86,7 6	89,03	89,03	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
0														
1														
2	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
3														
	E Allocat on of Lit gated Recovery		0		0	-89,03	0	0	0	0	0	0	0	-89,03
5														
6	Surcharge calculation													
7	Unrecovered costs (D E)	0	0	0		0	0	0	0	0	0	0	0	0
8	remaining life	2	36	8	60	72	8	8	8	8	8	8	8	
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	smal er of D or F	0	0	0	0	0	0	0	0	0	0	0	0	0
5														
55	forecas ed therm 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														
####	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 s te, are not exclusive to a particu ar 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
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			Keene												
													DEF055		
			(9/03 - 9/0) ool #1	(9/0 - 9/05) ool #2	(9/05 - 9/06) ool #3	(9/06 - 9/07) ool #	(9/07 - 9/08) ool #5	(9/08 - 9/09) ool #6	(9 09 - 9/10) ool #7	(9/10 - 9/11) ool #8	(9/11 - 9/12) ool #9	(9 12 - 6/13) ool #10	(7/13 - 6/14) pool #11	(7/14 - 6/15) pool #12	subtotal
1	1	Remediation costs (i.o. 500061)	0										[redacted]		
2		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)			18,831	823	0	0	0	0					
8		Transfer Credit from Gas Restructuring				0	0	0							
9	B	Subtotal - net recoveries	0	0	18,831	823	0	0	0	0	0	0			
10															
11	A-B	Total net expenses to recover	10,165	6,606	53,9 2	9,589	32	269	0	0	88	1, 00			
12															
13															
1		Surcharge revenue:													
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 200	0												-
22		Act November 200 - October 2005	0	0				0	0	0	0	0	-	-	-
23		Act November 2005- October 2006	0	0				0	0	0	0	0	-	-	-
2		Act November 2006- October 2007	0	0	-1 ,091										(14,091)
25		Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	-	-	-
26		Act November 2012- October 2013													-
27		Act November 2013- October 201													-
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 201 Base Rate Rev													-
33		Act Nov 201 -Oct 2015 Base Rate Rev													-
3		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	0	-	-	(14,091)
0															
1															
2	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	[redacted]		
3															
	E	Allocat on of Lit gated Recovery	0	0	0	0	-66,2	-269	0	0	0	0			
5															
6		Surcharge calculation													
7		Unrecovered costs (D E)	0	0	0			0	0	0	0	0			
8		remaining life	2	36	8	60	72	8	8	8	12	12			
9		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		smal er of D or F	0	0	0	0	0	0	0	0	0	0	[redacted]		
5															
55		forecas ed therm 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	179,574,679	179,574,679	182,899,057
56															
####		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar 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
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		Concord															
							Corrected per 2/08 Audit									DEF077	
		(9/03 - 9/07) ool #1 - #	(9/07 - 9/08) ool #5	(9/08 - 9/09) ool #6	(9/09 - 9/10) ool #7	(9/10 - 9/11) ool #8	(9/11 - 9/12) ool #9	(9/12 - 6/13) ool #10	(7/13 - 6/1) ool #11	(7/1 - 6/15) ool #12	(7/15 - 6/16) ool #13	(7/16 - 6/17) pool #14	(7/17 - 6/18) pool #15	(7/18 - 6/19) pool #16	(7/19 - 6/20) pool #17	(7/20 - 6/21) pool #18	s total
1	1 Remediation costs (i.o. 500061)	0										[redacted]					
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	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	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	Cash recover es (i.o. 50000)	0															
7	Recovery costs (i.o. 50000)		1, 32	-1,007													
8	Transfer Credit from Gas Restructuring	0															
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	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																	
1	Surcharge revenue:																
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 200	0															-
22	Act November 200 - October 2005	0															-
23	Act November 2005- October 2006	-27, 99	0	0	0	0	0	0	0	0	0	-	-	-	-	-	(27,499)
2	Act November 2006- October 2007	-28,181	0	0	0	0	0	0	0	0	0	-	-	-	-	-	(28,181)
25	Act November 2007- October 2008	0															-
26	Act November 2012- October 2013	0				-20,006	-20,006										(40,012)
27	Act November 2013- October 201	0				-12,7 9	-25, 97										(38,246)
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				-1,891											(1,891)
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				-13,816											(13,816)
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				-12,16											(12,164)
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				-6,79	-6,79										(13,588)
32	Act Nov 2013-Oct 201 Base Rate Rev	0															-
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															-
3	AES co lections	0															-
35	Gas Street overcollection	0															-
36	Pr or Period Pool under/overcollect on	19,182	271,21	0	0	0	0	0	0	0	0	-	-	-	-	-	
37																	
38																	
39	C Surcharge Subtotal	363,501	271,21	0	0	-67, 20	-52,297	0	0	0	0	-	-	-	-	-	(175,398)
0																	
1																	
2	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	[redacted]					
3																	
	E Allocat on of Lit gated Recovery	0	-268,051	-92,679	- 6,190	-1 ,702	0	0	0	0	0						
5																	
6	Surcharge calculation																
7	Unrecovered costs (D E)	0	0	0	0	0	0	0	0	23,398	27,301						
8	remaining life	1	72	8	8	12	12	12	12	12	2						
9	one year	36	12	12	12	12	12	12	12	12	12						
50	F amortization	0	0	0	0	0	0	0	0	23,398	13,650						
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	23,398	13,650	[redacted]					
5																	
55	forecas ed therm 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																	
####	surcharge per therm	$0.0000	$0.0000	$0 0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	[redacted]					

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

0440

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

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		General														DEF064		2021 MGP
		(9/02 - 9/07) ool #1 - #5	(9/07 - 9/08) ool #6	(9/08 - 9/09) ool #7	(9/09 - 9/10) ool #8	(9/10 - 9/11) ool #9	(9/11 - 9/12) ool #10	(9/12 - 6/13) ool #11	(7/13 - 6/1) ool #12	(7/1 - 6/15) ool #13	(7/15 - 6/16) ool #1	(7/16 - 6/17) ool #15	(7/17 - 6/18) ool #16	(7/18 - 6/19) ool #17	(7/19 - 6/20) ool #18	(7/20 - 6/21) ool #19	s total	Remediat on s total
1	1 Remediation costs (i.o. 500061)																0	[redacted]
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	Cash recover es (i.o. 500061)	0	0	0													0	
6	Cash recover es (i.o. 50000)																0	
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	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																		
11	A-B Total net expenses to recover	806,611	-168,319	-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	
12																		
13																		
1	Surcharge revenue:																	
15	Act June 1998 - October 1998																0	(54,889)
16	Act November 1998 - October 1999																0	(538,143)
17	Act November 1999 - October 2000																0	(912,804)
18	Act November 2000 - October 2001																0	(1,336,776)
19	Act November 2001 - October 2002																0	(1,679,228)
20	Act November 2002 - October 2003																0	(1,732,442)
21	Act November 2003 - October 200	-8,265															-8,265	(1,428,735)
22	Act November 200 - October 2005	-70,898															-70,898	(1,403,787)
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)
2	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)
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
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)
27	Act November 2013- October 201					-12,7 9	-12,7 9	-12,7 9									-38,2 6	(293,217)
28	Act Nov 2009-Oct 2010 Base Rate Rev																0	(10,611)
29	Act Nov 2010-Oct 2011 Base Rate Rev																0	(77,509)
30	Act Nov 2011-Oct 2012 Base Rate Rev																0	(68,244)
31	Act Nov 2012-Oct 2013 Base Rate Rev																0	(76,335)
32	Act Nov 2013-Oct 201 Base Rate Rev																0	(85,298)
33	Act Nov 201 -Oct 2015 Base Rate Rev																0	(86,554)
3	AES co lections																0	(266,571)
35	Gas Street overcollection																0	(23,511)
36	Pr or Period Pool under/overcollect on	1, 86,6	2,068,527	0	0	0	0	0	0	0	0	0	0	0	0	0		
37																		
38																		
39	C Surcharge Subtotal	1,261,916	2,068,527	0	0	-17,750	-17 750	-12,7 9	0	0	0	0	0	0	0	0	-272,977	(13,965,693)
0																		
1																		
2	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	[redacted]
3																		
	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	
5																		
6	Surcharge calculation																	
7	Unrecovered costs (D E)		0	0	0	0	0	0	0	-1,091	3,39	2,806	6,171	,906	6,095	5,6 6	27,926	
8	remaining life	72	8	8	8	12	12	12	12	12	2	36	8	60	72	8		
9	one year	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12		
50	F amortization	0	0	0	0	0	0	0	0	-1,091	1,697	935	1 5 3	981	1,016	807		
51																		
52	Required annual increase in rates:																	
53	smal er of D or F	0	0	0	0	0	0	0	0	-1,091	1,697	935	1,5 3	981	1 016	807	5,887	
5																		
55	forecas ed therm 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**
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	$0.0000	**$0.0129**

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

0441

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

		(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)	Total
1	1 Remediation costs (i.o. 500061)	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	[redacted]
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	115,8 1	69,261	11 ,228	8, 99	[redacted]
3	A Subtotal - remediation costs	23,629,969	,8 5,887	1,177 231	991,0 5	1,1 6,065	1,6 5,3 0	3,081, 56	8,287, 33	3,528,25	517,250	786,7 5	66,707	653,552	952,538	[redacted]
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	-169,1 0	[redacted]
6	Cash recover es (i.o. 50000)	- 5,985	0	0	0	0	0	0	0	0	0	0	0	0	0	[redacted]
7	Recovery costs (i.o. 50000)	1,918,3 0	39,173	22,9 6	0	0	-1 ,068	2,500,000	2, 75,750	0	0	0	0	0	0	[redacted]
8	Transfer Credit from Gas Restructuring	0	-3 331	0	0	0	0	0	0	0	0	0	0	0	0	[redacted]
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	-169,1 0	[redacted]
10																[redacted]
11	A-B Total net expenses to recover	22,167,780	3,731 277	1,1 1,9 6	877,655	835,839	1,526,211	,973,753	10,6 1,29	3, 08, 28	6 ,13	591,322	258,163	0,892	783,398	[redacted]
12																
13																
1	Surcharge revenue:															
15	Act June 1998 - October 1998	-5 ,889	0	0	0	0	0	0	0	0	0	0	0	0	0	(5 ,889)
16	Act November 1998 - October 1999	-538,1 3	0	0	0	0	0	0	0	0	0	0	0	0	0	(538,1 3)
17	Act November 1999 - October 2000	-912 80	0	0	0	0	0	0	0	0	0	0	0	0	0	(912,80)
18	Act November 2000 - October 2001	-1,336 776	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,336,776)
19	Act November 2001 - October 2002	-1,679,228	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,679,228)
20	Act November 2002 - October 2003	-1,732, 2	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,732, 2)
21	Act November 2003 - October 200	-1, 28,735	0	0	0	0	0	0	0	0	0	0	0	0	0	(1, 28,735)
22	Act November 200 - October 2005	-1, 03,787	0	0	0	0	0	0	0	0	0	0	0	0	0	(1, 03,787)
23	Act November 2005- October 2006	-1,69 ,877	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,69 ,877)
2	Act November 2006- October 2007	-2,036,113	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,036,113)
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
26	Act November 2012- October 2013	0	0	0	0	-30,009	-130,039	0	0	0	0	0	0	0	0	(160,0 8)
27	Act November 2013- October 201	0	0	0	0	-38,2 6	-165,731	-89,2 0	0	0	0	0	0	0	0	(293,217)
28	Act Nov 2009-Oct 2010 Base Rate Rev	0	0	0	0	-10,611	0	0	0	0	0	0	0	0	0	(10,611)
29	Act Nov 2010-Oct 2011 Base Rate Rev	0	0	0	0	-77,509	0	0	0	0	0	0	0	0	0	(77,509)
30	Act Nov 2011-Oct 2012 Base Rate Rev	0	0	0	0	-68,2	0	0	0	0	0	0	0	0	0	(68,2)
31	Act Nov 2012-Oct 2013 Base Rate Rev	0	0	0	0	-8,937	-67,398	0	0	0	0	0	0	0	0	(76,335)
32	Act Nov 2013-Oct 201 Base Rate Rev	0	0	0	0	0	-28, 33	-56,865	0	0	0	0	0	0	0	(85,298)
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	0	(86 55)
3	AES co lections	-69,391	-12,620	-12,90	-13,1 5	-13,221	-13,738	-27,673	-1 ,173	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	(266 571)
35	Gas Street overcollection	-23,511	0	0	0	0	0	0	0	0	0	0	0	0	0	(23 511)
36	Pr or Period Pool under/overcollect on	15,673,5 7												0	0	[redacted]
37																
38																
39	C Surcharge Subtotal	2,762,851	-12,620	-12,90	-13,1 5	-2 6,777	- 26,978	-217,055	-35,811	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	1,707,85
0																
1																
2	D Net balance to be recovered (A-B C)	2 ,930,631	3,718,657	1,129,0 2	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	[redacted]
3																
	E Allocat on of Lit gated Recovery															
5																
6	Surcharge calculation															
7	Unrecovered costs (D E)															
8	remaining life															
9	one year															
50	F amortization															
51																
52	Required annual increase in rates:															
53	smal er of D or F															
5																
55	forecas ed therm sales															
56																
####	surcharge per therm															

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

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

Calculation of Supplier Balancing Charge
2020-2021

Rate: $ 0.1807 /MMBtu

		Rate	Volume		Total	
Injection Cost		$ 0.0087	**386,014**	$	3,358	
Fuel	1.75%	$ 0.0481	**386,014**	$	18,577	
Withdrawal Cost		$ 0.0087	**195,768**	$	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	
			Total Cost	$	105,112	
		Absolute Value of the	Sendout Error		**581,782**	MMBtu
			Rate	$	0.1807	/MMBTU

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

TGP FSMA Injection Charge	$	0.0087	/ MMBtu
TGP FSMA Withdrawal Charge	$	0.0087	/ MMBtu
TGP FSMA Deliverability Charge	$	1.3094	/ 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

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov	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
Total	**5,979**	**5,803**	**176**	**14,714,420**	**14,524,173**	**190,246**	**581,782**	**386,014**	**195,768**

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 Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (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

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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 Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (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

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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	-1010.01989	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

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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.
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 Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Dec 24, 2020	13	13	0	37660.89922	37660.89922	0	0	0	0
Dec 25, 2020	20	19	1	50268.23604	48467.18792	1801.048117	1801.048117	1801.048117	0
Dec 26, 2020	36	35	1	79085.00591	77283.95779	1801.048117	1801.048117	1801.048117	0
Dec 27, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0
Dec 28, 2020	28	28	0	64676.62097	64676.62097	0	0	0	0
Dec 29, 2020	39	39	0	84488.15026	84488.15026	0	0	0	0
Dec 30, 2020	27	28	-1	62875.57286	64676.62097	-1801.04812	1801.048117	0	1801.048117
Dec 31, 2020	32	32	0	71880.81344	71880.81344	0	0	0	0
Jan 1, 2021	30	31	-1	69606.61887	71724.95338	-2118.3345	2118.334502	0	2118.334502
Jan 2, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0
Jan 3, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502
Jan 4, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	0
Jan 5, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0
Jan 6, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502
Jan 7, 2021	35	35	0	80198.29138	80198.29138	0	0	0	0
Jan 8, 2021	36	36	0	82316.62588	82316.62588	0	0	0	0
Jan 9, 2021	37	35	2	84434.96038	80198.29138	4236.669003	4236.669003	4236.669003	0
Jan 10, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003
Jan 11, 2021	35	36	-1	80198.29138	82316.62588	-2118.3345	2118.334502	0	2118.334502
Jan 12, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	0
Jan 13, 2021	33	31	2	75961.62238	71724.95338	4236.669003	4236.669003	4236.669003	0
Jan 14, 2021	32	31	1	73843.28788	71724.95338	2118.334502	2118.334502	2118.334502	0
Jan 15, 2021	28	26	2	65369.94987	61133.28087	4236.669003	4236.669003	4236.669003	0
Jan 16, 2021	27	24	3	63251.61537	56896.61186	6355.003505	6355.003505	6355.003505	0
Jan 17, 2021	29	25	4	67488.28437	59014.94637	8473.338006	8473.338006	8473.338006	0
Jan 18, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	0
Jan 19, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	0
Jan 20, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502
Jan 21, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003
Jan 22, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	0
Jan 23, 2021	46	46	0	103499.9709	103499.9709	0	0	0	0
Jan 24, 2021	43	43	0	97144.96739	97144.96739	0	0	0	0
Jan 25, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502
Jan 26, 2021	34	36	-2	78079.95688	82316.62588	-4236.669	4236.669003	0	4236.669003
Jan 27, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	0
Jan 28, 2021	47	47	0	105618.3054	105618.3054	0	0	0	0
Jan 29, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003
Jan 30, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003
Jan 31, 2021	46	48	-2	103499.9709	107736.6399	-4236.669	4236.669003	0	4236.669003
Feb 1, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0
Feb 2, 2021	36	33	3	83276.32165	78176.98524	5099.336415	5099.336415	5099.336415	0
Feb 3, 2021	35	32	3	81576.54285	76477.20643	5099.336415	5099.336415	5099.336415	0
Feb 4, 2021	37	39	-2	84976.10046	88375.65807	-3399.55761	3399.55761	0	3399.55761
Feb 5, 2021	32	36	-4	76477.20643	83276.32165	-6799.11522	6799.11522	0	6799.11522
Feb 6, 2021	39	37	2	88375.65807	84976.10046	3399.55761	3399.55761	3399.55761	0
Feb 7, 2021	37	40	-3	84976.10046	90075.43687	-5099.33642	5099.336415	0	5099.336415
Feb 8, 2021	46	45	1	100274.1097	98574.3309	1699.778805	1699.778805	1699.778805	0
Feb 9, 2021	45	45	0	98574.3309	98574.3309	0	0	0	0
Feb 10, 2021	43	43	0	95174.77329	95174.77329	0	0	0	0
Feb 11, 2021	49	47	2	105373.4461	101973.8885	3399.55761	3399.55761	3399.55761	0
Feb 12, 2021	49	46	3	105373.4461	100274.1097	5099.336415	5099.336415	5099.336415	0
Feb 13, 2021	42	38	4	93474.99448	86675.87926	6799.11522	6799.11522	6799.11522	0
Feb 14, 2021	38	36	2	86675.87926	83276.32165	3399.55761	3399.55761	3399.55761	0
Feb 15, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0
Feb 16, 2021	36	35	1	83276.32165	81576.54285	1699.778805	1699.778805	1699.778805	0
Feb 17, 2021	43	41	2	95174.77329	91775.21568	3399.55761	3399.55761	3399.55761	0
Feb 18, 2021	38	39	-1	86675.87926	88375.65807	-1699.77881	1699.778805	0	1699.778805
Feb 19, 2021	38	38	0	86675.87926	86675.87926	0	0	0	0
Feb 20, 2021	40	41	-1	90075.43687	91775.21568	-1699.77881	1699.778805	0	1699.778805
Feb 21, 2021	42	42	0	93474.99448	93474.99448	0	0	0	0
Feb 22, 2021	33	31	2	78176.98524	74777.42763	3399.55761	3399.55761	3399.55761	0
Feb 23, 2021	27	26	1	67978.31241	66278.5336	1699.778805	1699.778805	1699.778805	0
Feb 24, 2021	25	20	5	64578.7548	56079.86077	8498.894025	8498.894025	8498.894025	0
Feb 25, 2021	37	32	5	84976.10046	76477.20643	8498.894025	8498.894025	8498.894025	0
Feb 26, 2021	35	33	2	81576.54285	78176.98524	3399.55761	3399.55761	3399.55761	0
Feb 27, 2021	29	30	-1	71377.87002	73077.64882	-1699.77881	1699.778805	0	1699.778805
Feb 28, 2021	26	26	0	66278.5336	66278.5336	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 Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (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					
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	**Monthly Peaking MDQ**		**$ 54.72**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

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
Pipeline									
	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	
Storage									
	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	
Peaking									
	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.

REDACTED
Updated Schedule 21
Page 11 of 11

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

		Volume	Rate	Monthly Cost	Months/Year	Annual Cost
1		[redacted]				
2						
3						
4	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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

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

HLF	High Load Factor	59.25%	12.89%	27.85%	100%
LLF	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

Design DD		Base load	71.544 Heat load	Total
HLF	R-1 RNSH	102	457	558
LLF	R-3 RSH	3,545	69,811	73,356
LLF	G-41 SL	770	30,823	31,593
HLF	G-51 SH	739	1,812	2,551
LLF	G-42 ML	1,473	37,931	39,404
HLF	G-52 MH	1,781	3,820	5,601
LLF	G-43 LL	663	8,239	8,901
HLF	G-53 LLL90	1,146	2,222	3,368
HLF	G-54 LLG90	461	2,780	3,241
	TOTAL	10,678	157,896	168,574

HLF	4,227	11,092	15,319
LLF	6,450	146,804	153,255
Total	10,678	157,896	168,574

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	102	200	301	81	175.73	558
R-3 RSH	3,545	30,525	34,070	12,431	26,856	73,356
G-41 SL	770	13,477	14,247	5,488	11,857	31,593
G-51 SH	739	792	1,531	323	697	2,551
G-42 ML	1,473	16,585	18,058	6,754	14,592	39,404
G-52 MH	1,781	1,670	3,451	680	1,470	5,601
G-43 LL	663	3,602	4,265	1,467	3,169	8,901
G-53 LLL90	1,146	972	2,117	396	855	3,368
G-54 LLG90	461	1,216	1,676	495	1,070	3,241
TOTAL	10,678	69,040	79,718	28,115	60,741	168,574

HLF	4,227	4,850	9,077	1,975	4,267	15,319
LLF	6,450	64,190	70,641	26,140	56,474	153,255
Total	10,678	69,040	79,718	28,115	60,741	168,574

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	54.0%	14.6%	31.5%	100.0%
R-3 RSH	46.4%	16.9%	36.6%	100.0%
G-41 SL	45.1%	17.4%	37.5%	100.0%
G-51 SH	60.0%	12.6%	27.3%	100.0%
G-42 ML	45.8%	17.1%	37.0%	100.0%
G-52 MH	61.6%	12.1%	26.2%	100.0%
G-43 LL	47.9%	16.5%	35.6%	100.0%
G-53 LLL90	62.9%	11.7%	25.4%	100.0%
G-54 LLG90	51.7%	15.3%	33.0%	100.0%
TOTAL	47.3%	16.7%	36.0%	100.0%

High Load Factor	59.25%	12.89%	27.85%	100%
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

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Allocate Design Day Sendout to Rate Classes

Design DD **71.544**

	Daily Baseload * 1000	Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	102	6.01	430	532	19%	0.289%	102	457	558
R-3 RSH	3,545	918.47	65,711	69,256	5%	44.214%	3,545	69,811	73,356
G-41 SL	770	405.52	29,013	29,783	3%	19.521%	770	30,823	31,593
G-51 SH	739	23.84	1,706	2,445	30%	1.148%	739	1,812	2,551
G-42 ML	1,473	499.04	35,703	37,176	4%	24.023%	1,473	37,931	39,404
G-52 MH	1,781	50.26	3,596	5,376	33%	2.419%	1,781	3,820	5,601
G-43 LL	663	108.39	7,755	8,418	8%	5.218%	663	8,239	8,901
G-53 LLL90	1,146	29.24	2,092	3,238	35%	1.408%	1,146	2,222	3,368
G-54 LLG90	461	36.58	2,617	3,078	15%	1.761%	461	2,780	3,241
TOTAL	10,678	1,939.15	148,622	159,300		100.000%	10,678	157,896	168,574

HLF	4,227	146	10,440	14,668
LLF	6,450	1,793	138,182	144,632
Total	10,678	1,939	148,622	159,300

Design Day from 2020-2021 COG			**168,574**
Design Day from Gas Load Calculation			159,300
Variance			9,274

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

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 (Jul+Aug)/2	Daily Baseload
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															
	TOTAL	1,713	2,229	2,311	2,080	1,662	1,198	714	406	337	346	416	829	14,242	341.449	11.014
	HLF	204	235	246	231	194	168	166	138	136	142	140	173	2,174	131.050	4.480
	LLF	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 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	320	331	331	310	331	320	331	320	337	346	320	331	3,908
	HLF	127	131	131	123	131	127	131	127	136	142	127	131	1,547
	LLF	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
	TOTAL	1,393	1,898	1,980	1,771	1,331	878	383	86	0	0	95	498	10,333

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

Actual BDD	**846.0**	**1054.0**	**1025.0**	**963.0**	**724.0**	**491.0**	**257.0**	**31.0**	**0.0**	**4.0**	**87.0**	**341.0**	5823.0

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
	TOTAL	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
Docket No DE 98-124

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 Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6.0%				0.3927	0.3722	943.3700	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	1,165.6100	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	Nov 21 - Apr 22					0.9256	0.9056	1,200.9474	1,187.6074	$ -	0.00%						
24	Total									$ 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

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

		For Purposes Other Than Fuel Financing
12/31/2022 Projected Net Plant	$	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													**1.22%**

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													**1.08%**

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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**5 Quarter Avg**	**Q2 2020**	**Q3 2020**	**Q4 2020**	**Q1 2021**	**Q2 2021**
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	$ 50,349	$ 48,351	$ 54,291	$ 52,792	$ 51,959	$ 44,351
5		$ 3,016,100					
6	ROR	8.76%	Pre-Tax Rate of 6.64% and Statuatory Tax Rate of 27.08%				
		$ 264,132					
7	Income Tax Gross-up	1.2708					
8	Revenue Requirement	$ 335,667					

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LIBERTY UTILITIES

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II RATE SCHEDULES
FIRM RATE SCHEDULES

	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 95	LDAC Page 101	Total Rate	Delivery Charge	Cost of Gas Rate Page 92	LDAC Page 101	Total Rate
Residential Non Heating - R-1	~~$ 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~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.0020~~	~~$ 0.3860~~	~~$ 0.4914~~	~~$ 0.0589~~	~~$ 0.9363~~
Residential Heating - R-3	~~$ 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~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.1838~~	~~$ 0.5678~~	~~$ 0.4914~~	~~$ 0.0589~~	~~$ 1.1181~~
Residential Heating - R-4	~~$ 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			
Therms in the first block per month at	$ 0.3098	$ 0.6236	$ 0.1444	$ 1.0778	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.3123~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.6776~~	~~$ 0.5678~~	~~$ 0.4914~~	~~$ 0.0589~~	~~$ 1.1181~~
Commercial/Industrial - G-41	~~$ 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				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~~
Commercial/Industrial - G-42	~~$ 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~~
Commercial/Industrial - G-43	~~$ 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~~
Commercial/Industrial - G-51	~~$ 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~~	~~$ 0.7386~~
Commercial/Industrial - G-52	~~$ 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~~
Commercial/Industrial - G-53	~~$ 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~~
Commercial/Industrial - G-54	~~$ 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~~

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LIBERTY UTILITIES

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	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**
Residential Non Heating - R-5	~~$ 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~~
Residential Heating - R-6	~~$ 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~~	~~$ 1.1118~~
Residential Heating - R-7	~~$ 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~~	~~$ 1.1118~~
Commercial/Industrial - G-44	~~$ 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~~	~~$ 1.0221~~	~~$ 0.4114~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7778~~
Commercial/Industrial - G-45	~~$ 224.11~~			~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
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~~
							~~$ -~~	
Commercial/Industrial - G-46	~~$ 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~~	~~$ 0.1565~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.5229~~
Commercial/Industrial - G-55	~~$ 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~~
Commercial/Industrial - G-56	~~$ 224.11~~			~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
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~~	~~$ 0.6051~~
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~~	
Commercial/Industrial - G-57	~~$ 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~~	~~$ 0.8431~~	~~$ 0.1063~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4817~~
Commercial/Industrial - G-58	~~$ 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~~

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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)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 2,919,324~~		$ 3,276,842	
Supply Costs:	~~2,202,631~~		6,971,475	
Storage Gas:				
Demand, Capacity:			-	
Commodity Costs:			-	
Produced Gas:	~~22,682~~		82,504	
Hedged Contract Savings			-	
			-	
Unadjusted Anticipated Cost of Gas		~~$ 5,144,637~~		$ 10,330,821
Adjustments:				
Prior Period (Over)/Under Recovery as of ~~April 30, 2018~~ September 01, 2019 (monthly adjustment filing	~~$ 1,885,446~~		$ 4,472,186	
Interest	~~51,144~~		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			-	
Total Adjustments		~~1,936,590~~		4,695,023
Total Anticipated Direct Cost of Gas		~~$ 7,081,227~~		$ 15,025,844
Anticipated Indirect Cost of Gas				
Working Capital:				
Total anticipated Direct Cost of Gas ~~(05/01/2018 - 10/31/2018)~~ (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	~~0.127%~~		0.01%	
Working Capital	~~6,538~~		$ 769	
Plus: Working Capital Reconciliation ~~(Acct 142.20)~~ (Acct 1163-1424)	~~(18,982)~~		4,555	
Total Working Capital Allowance		~~$ (12,443)~~		$ 5,324
Bad Debt:				
Total anticipated Direct Cost of Gas ~~(05/01/2018 - 10/31/2018)~~ (05/01/19 - 10/31/19)	~~$ 5,144,637~~		$ 10,330,821	
Less: Refunds	-		-	
Plus: Total Working Capital	~~(12,443)~~		5,324	
Plus: Prior Period (Over)/Under Recovery	~~1,885,446~~		4,472,186	
Subtotal	~~$ 7,017,640~~		$ 14,808,331	
Bad Debt Percentage	~~1.11%~~		0.70%	
Bad Debt Allowance	~~77,896~~		103,658	
Plus: Bad Debt Reconciliation ~~(Acct 175.52)~~ (Acct 1163-1754)	~~(280,167)~~		23,159	
Total Bad Debt Allowance		~~(202,272)~~		126,817
Production and Storage Capacity		~~-~~		-
Miscellaneous Overhead ~~(05/01/2018 - 10/31/2018)~~ (05/01/19 - 10/31/19)	~~$ 13,170~~		$ -	
Times Summer ~~Winter~~ Sales	~~20,973~~		23,366	
Divided by Total Sales	~~109,299~~		115,043	
Miscellaneous Overhead		~~2,527~~		-
Total Anticipated Indirect Cost of Gas		~~$ (212,188)~~		$ 132,141
Total Cost of Gas		~~$ 6,869,039~~		$ 15,157,985

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NHPUC NO. 11 - GAS **Proposed Third Revised Page 92**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 92**

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	~~$ 9,653,380~~		$ 15,025,844		
Projected Prorated Sales (05/01/22 - 10/31/22) ~~(05/01/21 - 10/31/21)~~	~~20,973,031~~		27,125,444		
Direct Cost of Gas Rate		~~$ 0.4603~~		$ 0.5539	per therm
Demand Cost of Gas Rate	~~$ 4,548,346~~	~~$ 0.2169~~	$ 3,276,842	$ 0.1208	
Commodity Cost of Gas Rate	~~3,136,847~~	~~$ 0.1496~~	7,053,979	$ 0.2601	
Adjustment Cost of Gas Rate	~~1,968,188~~	~~$ 0.0938~~	4,695,023	$ 0.1731	
Total Direct Cost of Gas Rate	~~$ 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) ~~(05/01/21 - 10/31/21)~~	~~20,973,031~~		27,125,444		
Indirect Cost of Gas		~~$ (0.0083)~~		$ 0.0048	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22				$ 0.5587	per Therm
~~**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21**~~		~~$ 0.4520~~			

RESIDENTIAL COST OF GAS RATE - 05/01/2022	**COGsr**	**$ 0.5587**	**/therm**	
~~**RESIDENTIAL COST OF GAS RATE - 5/01/21**~~	~~**COGsr**~~	~~**$ 0.4520**~~	~~**/therm**~~	
Maximum	(COG + 25%)	~~$ 0.5650~~	$ 0.6984	

COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2022	**COGsl**	**$ 0.5580**	**/therm**	
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2021**~~	~~**COGsl**~~	~~**$ 0.4591**~~	~~**/therm**~~	

Average Demand Cost of Gas Rate Effective ~~05/01/21~~ 05/01/2022	~~$ 0.2169~~	$ 0.1208	Maximum	(COG + 25%)	~~$ 0.5739~~	$ 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				

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2021	**COGsh**	**$ 0.5593**	**/therm**	
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2020**~~	~~**COGsh**~~	~~**$ 0.4474**~~	~~**/therm**~~	

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)	~~0.9918~~	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
Issued by: ______________________
Neil Proudman
Effective: ~~November 1, 2020~~ November 1, 2021
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

Ln	(a)	Reference (b)	OP 22 May - Oct (c)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**		Updated Summary
2			Page 1 of 1
3	**Off Peak 2022 Summer Cost of Gas Filing**		
4	**Summary**		
5			OP 22
6		Reference	May - Oct
7	(a)	(b)	(c)
8			
9	**Anticipated Direct Cost of Gas**		
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	**Total Unadjusted Cost of Gas**		$ 10,330,821
24			
25	**Adjustments:**		
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	**Total Adjustments**		$ 4,695,023
41			
42	**Total Anticipated Direct Costs**	lns 23 + 40	$ 15,025,844
43			
44	**Anticipated Indirect Cost of Gas**		
45	**Working Capital**		
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	**Total Working Capital Allowance**	lns 50 + 51	$ 4,555
54			
55	**Bad Debt**		
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		$ 14,807,562
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	**Total Bad Debt Allowance**	lns 63 + 64	$ 126,812
67			
68	**Production and Storage Capacity**	per GTC17(f)	$ -
69			
70	**Miscellaneous Overhead**	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		20.31%
74			
75	**Miscellaneous Overhead**	lns 70 * 73	$ -
76			
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$ 131,366
78			
79	**Total Cost of Gas**	lns 42 + 77	$ 15,157,210
80			
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52	27,125,444

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
										Page 1 of 4
5										
6										Off Peak Period
7	For Month of:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	May - Oct
8	(a)	(b)	(c)	(d)	(e)	(d)	(e)	(f)	(g)	(h)
9	**I. Gas Volumes (Therms)**									
10										
11	**A. Firm Demand Volumes**		87,054	267,289	220,723	223,909	335,525	722,212	855,832	
12	Firm Gas Sales	Sch. 10B, ln 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, ln 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, ln 63	739,535	95,658	-	-	206,295	636,518		1,678,006
22	Niagara Supply	Sch. 6, ln 64	668,413	540,809	542,484	545,801	591,423	687,667		3,576,596
23	TGP Supply (Gulf)	Sch. 6, ln 65	13,120	-	-	-	-	384,326		397,446
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	-	-	-	-		-
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	-	-	-	-	436,185		436,185
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	44,883	18,131	-	-	55,566	20,602		139,181
28	Propane Truck	Sch. 6, ln 70	79,409	71,899	69,472	69,279	73,449	81,696		445,204
29	PNGTS	Sch. 6, ln 71	205,081	146,300	119,612	125,908	176,916	218,093		991,910
30	Portland Natural Gas	Sch. 6, ln 72	152,602	3,126	-	-	2,555	574,003		732,286
31	TGP Supply (Zone 4)	Sch. 6, ln 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, ln 78	-	-	-	-	-	-		-
36										
37	Produced Gas:									
38	LNG Vapor	Sch. 6, ln 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, ln 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, ln 87	(44,883.07)	(18,131.18)	-	-	(55,565.66)	(20,601.58)		(139,181.49)
44	Propane	Sch. 6, ln 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, ln 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	lns 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**									
2										
3	**Off Peak 2022 Summer Cost of Gas Filing**									
4	**Summary of Supply and Demand Forecast**									
49										**REDACTED**
50	**II. Gas Costs**									Updated Schedule 1
51										Page 2 of 4
52	**A. Demand Costs**									
53	Supply									
54	Niagara Supply	Sch.5A, ln 12	[redacted]							
55	Subtotal Supply Demand									
56	Less Capacity Credit									
57	Net Pipeline Demand Costs									
58										
59	Pipeline:									
60	Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]							
61	Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, ln 17								
62	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18								
63	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19								
64	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20								
65	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21								
66	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22								
67	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	Sch.5A, ln 23								
68	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 24								
69	Portland Natural Gas Trans Service	Sch.5A, ln 25								
70	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 27								
71	Portland Natural Gas	Sch.5A, ln 25								
72	TransCanada via Union to Portland	Sch.5A, ln 27								
73	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 29								
74	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 30								
75	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 31								
76	National Fuel FST 2358	Sch.5A, ln 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, ln 37	[redacted]							
83	Granite Ridge Demand	Sch.5A, ln 38								
84	DOMAC Demand NSB041	Sch.5A, ln 39								
85	Subtotal Peaking Demand									
86	Less Capacity Credit									
87	Net Peaking Supply Demand Costs									
88										
89	Storage:									
90	Dominion - Demand	Sch.5A, ln 49	[redacted]							
91	Dominion - Storage	Sch.5A, ln 50								
92	Honeoye - Demand	Sch.5A, ln 51								
93	National Fuel - Demand	Sch.5A, ln 52								
94	National Fuel - Capacity	Sch.5A, ln 53								
95	Tenn Gas Pipeline - Demand	Sch.5A, ln 54								
96	Tenn Gas Pipeline - Capacity	Sch.5A, ln 55								
97	Subtotal Storage Demand		$ -	$ -	$ -	$ -	$ -	$ -		$ -
98	Less Capacity Credit		-	-	-	-	-	-		-
99	Net Storage Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -		$ -
100										
101	Total Demand Charges	lns 55 + 77 + 85 + 97	$ 823,110	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 3,703,482	$ 4,954,402
102	Total Capacity Credit	lns 56 + 78 + 86 + 98	(278,705)	(279,771)	(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	$ 546,487	$ 2,449,483	$ 3,276,842
104				**THIS PAGE HAS BEEN REDACTED**						

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**
105 **REDACTED**
106 Updated Schedule 1
107 **B. Commodity Costs** Page 3 of 4

108	Pipeline:								
109	Dawn Supply	Sch. 6, ln 12	[redacted]						
110	Niagara Supply	Sch. 6, ln 13							
111	TGP Supply (Gulf)	Sch. 6, ln 14							
112	Dracut Supply 1 - Baseload	Sch. 6, ln 15							
113	Dracut Supply 2 - Swing	Sch. 6, ln 16							
114	Dracut Supply 3 - Swing	Sch. 6, ln							
115	City Gate Delivered Supply	Sch. 6, ln 17							
116	LNG Truck	Sch. 6, ln 18							
117	Portland Natural Gas	Sch. 6, ln 21							
118	PNGTS	Sch. 6, ln 20							
119	TGP Supply (Zone 4)	Sch. 6, ln 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	Storage:								
123	TGP Storage - Withdrawals	Sch. 6, ln 48	$ -	$ -	$ -	$ -	$ -	$ -	$ -
124									
125	Produced Gas Costs:								
126	LNG Vapor	Sch. 6, ln 51	[redacted]						
127	Propane	Sch. 6, ln 52							
128	Subtotal Produced Gas Costs		$ 13,993	$ 13,159	$ 12,913	$ 12,877	$ 13,652	$ 15,911	$ 82,504
129									
130	Less Storage Refills:								
131	LNG Truck	Sch. 6, ln 38	[redacted]						
132	Propane	Sch. 6, ln 39							
133	TGP Storage Refill	Sch. 6, ln 40							
134	Storage Refill (Trans.)	Sch. 6, ln 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	**C. Supply Volumetric Transportation Costs:**								
140	Dawn Supply	Sch. 6, ln 27	[redacted]						
141	Niagara Supply	Sch. 6, ln 28							
142	TGP Supply (Zone 4)	Sch. 6, ln 29							
143	Dracut Supply 1 - Baseload	Sch. 6, ln 30							
144	Dracut Supply 2 - Swing	Sch. 6, ln 31							
145	Dracut Supply 3 - Swing	Sch. 6, ln							
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, ln 33	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149									
150	Total Supply Volumetric Trans. Costs	lns 146 + 148	$ 88,990	$ 71,093	$ 70,660	$ 70,003	$ 71,501	$ 87,078	$ 459,325
151									
152	Total Commodity Gas & Trans. Costs	lns 137 + 150	$ 1,725,162	$ 808,556	$ 641,038	$ 623,542	$ 864,157	$ 2,391,524	$ 7,053,979
153									
154			**THIS PAGE HAS BEEN REDACTED**						
155									
156									

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**								
157	**D. Supply and Demand Costs by Source**								**REDACTED**
158									Updated Schedule 1
159									Page 4 of 4
160	Purchased Gas Demand Costs								
161	Pipeline Gas Demand Costs	lns 55 + 77	$ 823,110	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 4,954,402
162	Peaking Gas Demand Costs	ln 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	lns 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	ln 97	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169	Less Capacity Credit	ln 98	-	-	-	-	-	-	-
170	Net Storage Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
171									
172	**Total Demand Costs**	lns 165 + 170	$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 3,276,842
173									
174	Purchased Gas Supply								
175	Commodity Costs	ln 120	[redacted]						
176	Less Storage Inj.(TGP Storage)	ln 133							
177	Less Storage Transportation	ln 134							
178	Less LNG Truck	ln 131							
179	Less Propane Truck	ln 132							
180	Plus Transportation Costs	ln 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	ln 123	$ -	$ -	$ -	$ -	$ -	$ -	$ -
185	Transportation Costs	ln 148	-	-	-	-	-	-	-
186	Subtotal Storage Commodity Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
187									
188	Produced Gas Commodity Costs	ln 128	$ 13,993	$ 13,159	$ 12,913	$ 12,877	$ 13,652	$ 15,911	$ 82,504
189									
190	**Subtotal Commodity Costs**	lns 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		$ -	$ -	$ -	$ -	$ -	$ -	$ -
193									
194	**Total Commodity Costs**	lns 190 + 192	$ 1,725,162	$ 808,556	$ 641,038	$ 623,542	$ 864,157	$ 2,391,524	$ 7,053,979
195									
196	**Total Demand Costs**	ln 103	$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 3,276,842
197	**Total Supply Costs**	ln 194	1,725,162	808,556	641,038	623,542	864,157	2,391,524	7,053,979
198									
199	**Total Direct Gas Costs**	lns 196 + 197	$ 2,269,567	$ 1,355,043	$ 1,187,525	$ 1,170,030	$ 1,410,644	$ 2,938,011	$ 10,330,821
200									
201					THIS PAGE HAS BEEN REDACTED				

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

Updated Schedule 2
Page 1 of 1

Off Peak 2022 Summer Cost of Gas Filing
Contracts Ranked on a per Unit Cost Basis

Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Off Peak Cost per Unit Dth
(a)	(b)	(c)	(d)	(e)	(f)
Demand Costs					
ANE (TransCanada via Union to Iroquois)	Dawn - Parkway to Iroquois	Transportation	MDQ	4,047	[redacted]
Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
Dominion - Demand	GSS 300076	Storage	MDQ	934	
National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	40,000	
National Fuel	FST N02358	Transportation	MDQ	6,098	
Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	5,077	
Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
Portland Natural Gas	FTN	Transportation	MDQ	5,000	
Supply Costs - Commodity					
LNG Truck		Pipeline	Dkt	13,918	[redacted]
TGP Supply (Zone 4)		Pipeline	Dkt	2,986,627	
Niagara Supply		Pipeline	Dkt	357,660	
Dracut Supply 2 - Swing		Pipeline	Dkt	43,619	
Dawn Supply		Pipeline	Dkt	167,801	
TGP Citygate Supply		Pipeline	Dkt	-	
PNGTS		Pipeline	Dkt	99,191	
Dracut Supply 1 - Baseload		Pipeline	Dkt	-	
TGP Supply (Gulf)		Pipeline	Dkt	39,745	
LNG Vapor		Produced	Dkt	11,227	
Propane		Pipeline	Dkt	-	
Supply Costs - Volumetric Transportation					
Dracut Supply 1 - Baseload		Pipeline	Dkt	-	[redacted]
TGP Supply (Zone 4)		Pipeline	Dkt	39,745	
Dracut Supply 2 - Swing		Pipeline	Dkt	43,619	
Dawn Supply		Storage	Dkt	167,801	
Niagara Supply		Pipeline	Dkt	357,660	

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

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

Updated Schedule 3
Page 1 of 3

Ln	(a)	Days in Month (b)	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)
11	**Account 8840-2-0000-10-1920-1741 (formerly, 175.40) COG (Over)/Under Balance - Interest Calculation**																
12																	
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		-	-	-	-	-	-	-		2,320,472	2,344,240	2,364,010	2,399,424	2,386,442	2,350,111	14,164,699
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	
23																	
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%		
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
27																	
28	**(Over)/Under Balance**	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
29																	
30																	
31	**Calculation of COG with Interest**																
32																	
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		-	-	-	-	-	-	-		2,349,780	2,373,848	2,393,867	2,429,728	2,416,583	2,379,793	14,343,599
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	**(Over)/Under Balance**		$ 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)
45																	
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		
47																	
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
49																	
50	**(Over)/Under Balance**	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
51																	
52																	
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)	
59																	
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)	
63																	
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	
65																	
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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3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln																	
71			Prior Period Balance	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Off Peak Period
72		Days in Month	Plus Nov Collections	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
73			October 31, 2021														
74	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
76	**Account 8840-2-0000-10-1163-1424 (formerly, 142.40) Working Capital (Over)/Under Balance - Interest Calculation**																
78	**Beginning Balance**	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
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		-	-	-	-	-	-	-	-	-	-	-	-	-	-
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)		(4,171)
86	Reverse Prior Month Unbilled										683	690	696	707	703	692	4,171
88	Add Net Adjustments			-	-		-	-	-	-	-	-	-	-	-	-	-
90	Working Capital Billed	Account 1163-1424 2/															-
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	$ -
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		
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%		
98	Interest Applied	In 94 * In 96 / 365 * Days of Month		$ 20	$ 20	$ 20	$ 19	$ 21	$ 20	$ 19	$ 16	$ 14	$ 13	$ 10	$ 7		$ 199
100	**(Over)/Under Balance**	In 92 + In 98	$ 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	$ 199	199
103	**Calculation of Working Capital with Interest**																
105	**Beginning Balance**		$ 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)		(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)
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		
119	Interest Applied	In 96 * In 117 / 365 * Days of Month		20	20	20	19	21	20	19	16	14	12	10	6	-	$ 197
121	**(Over)/Under Balance**	-In 114 +In 115 + In 119	$ 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	$ 6	$ 6
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)	
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	
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	

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 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line																	
130																	
131																	
132			Prior Period Balance														
133			Plus Nov Collections	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Off Peak Period
134		Days in Month	October 31, 2021	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
135	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
136																	
137	**Account 8840-2-0000-10-1163-1754 (formerly, 175.54) Bad Debt (Over)/Under Balance - Interest Calculation**																
138																	
139	Forecast Direct Gas Costs	In 34		$ -	$ -	$ -	$ -	$ -	$ -	$ 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 106 + (May includes prior period)		-	-	-	-	-	-	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
143																	
144	**Beginning Balance**	Account 1163-1754 1/	**$ 23,159**	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 23,768	$ 21,839	$ 24,161	$ 27,716	$ 30,876	$ 30,725	$ 22,710	$ 23,159
145		**Oct Collections & Unbilled**															
146	Forecast Bad Debt	In 142 * 0.007		-	-	-	-	-	-	21,911	15,477	14,305	14,182	15,866	26,558		108,300
147																	
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)	(19,974)		(120,391)
150	Reverse Prior Month Unbilled										19,723	19,925	20,093	20,394	20,283	19,974	120,391
151																	-
152	Bad Debt Billed	Account 1163-1754 2/			-		-	-	-								-
153	Add Net Adjustments	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-
154																	
155	Monthly (Over)/Under Recovery		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 21,738	$ 24,161	$ 27,600	$ 30,746	$ 30,592	$ 22,591	$ 1,208	$ -
156																	
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	
158																	
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%		
160																	
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																	
163	**(Over)/Under Balance**	In 155 + In 161	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	**$ 23,768**	$ 21,839	$ 24,260	$ 27,716	$ 30,876	$ 30,725	$ 22,710	$ 11,959	1,307
164																	
165																	
166	**Calculation of Bad Debt with Interest**																
167																	
168	**Beginning Balance**		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 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										23,777	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	$ 23,666	$ 16,917	$ 16,623	$ 17,917	$ 18,746	$ 15,226	$ 20	$ (25,988)	$ (26,328)
177																	
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)	
179																	
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
181																	
182	**(Over)/Under Balance**	-In 174 +In 176 + In 180	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 23,768	$ 16,906	$ 16,596	$ 17,879	$ 18,697	$ 15,167	$ (65)	$ (25,988)	$ (25,988)
183																	
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		
186																	
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	
188																	
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	
190																	
191																	
192																	
193	**Total Interest**	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**

Updated Schedule 4
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3 **Off Peak 2022 Summer Cost of Gas Filing**

4 **Adjustments to Gas Costs**

5

	Adjustments	**Prior Period Adjustments**	**Refunds from Suppliers / Pipelines**	**Broker Revenue**	**Fuel Financing**	**Transportation CGA Revenues**	**Interruptible Sales Margin**	**Off System Sales Margin**	**Capacity Release Margin**	**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	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)

Ln	(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)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										**REDACTED**
2											Updated Schedule 5A
3	**Off Peak 2022 Summer Cost of Gas Filing**										Page 1 of 2
4	**Demand Costs**										
5											
6										Off Peak	Peak
7										May - Oct	May - Oct
8		Peak	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Subtotal Supply Demand & Reservation Charges			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7		Sch 5B, ln * Sch 5C ln 25 x days								
24	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 28 x days								
25	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 30 x days								
26	Portland Natural Gas		Sch 5B, ln 21 * Sch 5C ln 31 x days								
27	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 22 * Sch 5C ln 48 x days								
28	TransCanada via Union to Portland		Sch 5B, ln 23 * Sch 5C ln 49 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 24 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 25 * Sch 5C ln 36 x days								
31	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 38 x days								
32	National Fuel FST 2358	peak	Sch 5B, ln 27 * Sch 5C ln 40 x days								
33											
34	Subtotal Pipeline Demand Charges			$ 1,640,391	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 4,954,402	$ 4,903,685
35											
36	**Peaking Supply**										
37	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 30 * Sch 5C ln 28 x days	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	Granite Ridge Demand	peak	Sch 5B, ln 31 * Sch 5C ln 59 x days	-	-	-	-	-	-	-	-
39	DOMAC Demand NSB041	peak	Per Contract	-	-	-	-	-	-	-	
40	Subtotal Peaking Demand Charges			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41											
42	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 34 + ln 40	$ 1,640,391	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 4,954,402	$ 4,903,685
43											
44	Less Transportation Capacity Credit			$ (555,436)	$ (556,502)	$ (556,502)	$ (556,502)	$ (556,502)	$ (556,502)	$ (1,677,561)	$ (1,660,388)
45											
46	**Total Supply, Pipeline & Peaking Demand**			$ 1,084,955	$ 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										
3	**Off Peak 2022 Summer Cost of Gas Filing**									
4	**Demand Costs**									
47										
48	**Storage**									
49	Dominion - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 63 x days	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ -	$ 10,488
50	Dominion - Storage	peak	Sch 5B, ln 36 * Sch 5C ln 64 x days	1,489	1,489	1,489	1,489	1,489	1,489	-	8,935
51	Honeoye - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 67 x days	8,351	8,351	8,351	8,351	8,351	8,351	-	50,105
52	National Fuel - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 69 x days	16,053	16,053	16,053	16,053	16,053	16,053	-	96,318
53	National Fuel - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 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, ln 41 * Sch 5C ln 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, ln 42 * Sch 5C ln 74 x days	27,931	27,931	27,931	27,931	27,931	27,931	-	167,586
56											
57	**Subtotal Storage Demand Costs**			$ 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	**Total Storage Demand Costs**		ln 57 + ln 59	$ 76,792	$ 76,792	$ 76,792	$ 76,792	$ 76,792	$ 76,792	$ -	$ 460,750
62											
63	**Total Demand Charges**		ln 42 + ln 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		ln 44 + ln 59	$ (594,749)	$ (595,815)	$ (595,815)	$ (595,815)	$ (595,815)	$ (595,815)	$ (1,677,561)	$ (1,896,266)
66											
67	**Total Demand Charges less Cap. Cr.**		ln 63 + ln 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	**Total Off Peak Demand**			$ 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	**Total Peak Demand**			$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ -	$ 3,704,047

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 5B
2 Page 1 of 1
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Demand Volumes**
5

Line			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	**Supply**									
9		Niagara Supply			-	-	-	-	-	-
10										
11	**Pipeline**									
12		Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
13		Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
14		Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
15		Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
16		Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
17		Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
18		Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
		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	**Peaking**									
30		Tenn Gas Pipeline (Concord Lateral)	peak		-	-	-	-	-	-
31		Granite Ridge Demand	peak		-	-	-	-	-	-
32		DOMAC Liquid Demand Charge	peak	NSB041	-	-	-	-	-	-
33										
34	**Storage**									
35		Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
36		Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
37		Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
38		Honeoye - Capacity	peak	SS-NY	245,380	245,380	245,380	245,380	245,380	245,380
39		National Fuel - Demand	peak	FSS-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

Line	Description	Contract	Rate	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
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					**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**
6	**Tariff Rates**				31	30	31	31	30	31	184	30	31	31	28	31	30
7					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate						
8	**Supply**																
9	Niagara Supply		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10																	
11	**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
13																	
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
15																	
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
17																	
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
19																	
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
21																	
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
23																	
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
25																	
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
27																	
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
29																	
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
31																	
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
33																	
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
35																	
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
37																	
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
39																	
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
41																	
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
49																	
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	$ 0.0015	$ 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

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

58 **THIS PAGE HAS BEEN REDACTED**

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**

Updated Schedule 6
Page 2 of 5

59									
60	**Volumes (Therms)**								
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**		4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820
94									
95									
96									

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**								
97									**REDACTED**
98	**Gas Costs and Volumetric Transportation Rates**								Updated Schedule 6
99									Page 3 of 5
100	**Pipeline Gas:**								
101	**Dawn Supply**								Average Rate
102	NYMEX Price	Sch 7, ln 10/10	[redacted]						
103	Basis Differential								
104	**Net Commodity Costs**								
105									
106	**Niagara Supply**								
107	NYMEX Price	Sch 7, ln 10/10	[redacted]						
108	Basis Differential								
109	**Net Commodity Costs**								
110									
111	**Dracut Supply 1 - Baseload**								
112	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
113	Basis Differential								
114	**Net Commodity Costs**								
115									
116	**Dracut Supply 2 - Swing**								
117	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
118	Basis Differential								
119	**Net Commodity Costs**								
120									
121	**Dracut Supply 3 - Swing**	Sch 7, ln 10 / 10							
122	Commodity Costs - NYMEX Price		[redacted]						
123	Basis Differential								
124	**Net Commodity Costs**								
125									
126	**TGP Supply (Gulf)**								
127	NYMEX Price	Sch 7, ln 10/10	[redacted]						
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131									
132	**TGP Citygate Supply**								
133	NYMEX Price	Sch 7, ln 10/10	[redacted]						
134	Basis Differential								
135	**Net Commodity Costs**								
136									
137	**LNG Truck**	Sch 7, ln 10/10	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
138									
139	**Propane Truck**	NYMEX - Propane	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
140									
141	**PNGTS**								
142	NYMEX Price	Sch 7, ln 10/10	[redacted]						
143	Additional Cost								
144	**Net Commodity Cost**								
145									
146	**PNGTS EXP**								
147	NYMEX Price	Sch 7, ln 10/10	[redacted]						
148	Basis Differential								
149	**Net Commodity Cost**								
150									
151	**TGP Supply (Zone 4)**								
152	NYMEX Price	Sch 7, ln 10/10	[redacted]						
153	Basis Differential								
154	**Net Commodity Cost**		**$0.3562**	**$0.3524**	**$0.3620**	**$0.3531**	**$0.3135**	**$0.3150**	**$0.3420**
155									
156	**LNG Vapor (Storage)**	Sch 13, ln 97 /10	**$0.6988**	**$0.7258**	**$0.7371**	**$0.7371**	**$0.7371**	**$0.7723**	**$0.7347**
157									
158	**Propane**	Sch 13, ln 67 /10	**$1.1475**	**$1.0155**	**$0.9197**	**$0.8429**	**$0.7781**	**$0.7194**	**$0.9038**
159									
160	**Storage Refill:**								
161	**LNG Truck**	ln 137	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
162	**Propane**	ln 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.**								
2									
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
165									**REDACTED**
166									Updated Schedule 6
167									Page 4 of 5
182	**Per Unit Volumetric Transportation Rates**								
183	**Dawn Supply Volumetric Transportation Charge**								Average Rate
184	**Commodity Costs**	ln 104	[redacted]						
185									
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$	ln 186 x ln 187 x ln 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	ln 184 x ln 190	$0.00283	$0.00256	$0.00000	$0.00000	$0.00000	$0.00000	$0.00090
192	Subtotal TransCanada		**$0.00323**	**$0.00296**	**$0.00040**	**$0.00040**	**$0.00040**	**$0.00040**	**$0.00130**
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		**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**
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	ln 184 x ln 198	**$0.00382**	**$0.00384**	**$0.00387**	**$0.00385**	**$0.00384**	**$0.00385**	**$0.00385**
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	ln 184 x ln 200	**$0.00329**	**$0.00330**	**$0.00333**	**$0.00331**	**$0.00330**	**$0.00331**	**$0.00331**
202	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01092**	**$0.01068**	**$0.00818**	**$0.00814**	**$0.00812**	**$0.00814**	**$0.00903**
203									
204									
205	**Niagara Supply Volumetric Transportation Charge**								
206	**Commodity Costs**	Ln 109	[redacted]						
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	$0.00012	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
210	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00717**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**
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	ln 206 x ln 211	**$0.00311**	**$0.00313**	**$0.00316**	**$0.00314**	**$0.00313**	**$0.00314**	**$0.00314**
213	**Total Volumetric Transportation Rate - Niagara Supply**		**$0.01028**	**$0.01030**	**$0.01033**	**$0.01031**	**$0.01030**	**$0.01031**	**$0.01031**
214									
215									
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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**								
217									**REDACTED**
218									Updated Schedule 6
219									Page 5 of 5
220	**TGP Direct Volumetric Transportation Charge**								Average Rate
221	**Commodity Costs**	Ln 127	[redacted]						
222									
223	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
224	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
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	19th Rev Sheet No. 15	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331
229	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
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	17th Rev Sheet No. 32	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	17th Rev Sheet No. 32	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	ln 221 x ln 235	**$0.00592**	**$0.00597**	**$0.00604**	**$0.00605**	**$0.00599**	**$0.00599**	**$0.00599**
240	TGP - Fuel Charge % - Z 1-6	ln 221 x ln 238	**$0.01066**	**$0.01076**	**$0.01088**	**$0.01089**	**$0.01079**	**$0.01078**	**$0.01080**
241	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04112**	**$0.04128**	**$0.04146**	**$0.04148**	**$0.04133**	**$0.04131**	**$0.04133**
242									
243	**TGP (Zone 4 Purchase) Volumetric Transportation Charge**								
244	**Commodity Costs**	Ln 127	[redacted]						
245									
246	TGP - Max Comm. Base Rate - Z 4-6	19th Rev Sheet No. 15	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928
247	TGP - Max Commodity ACA Rate - Z 4-6	19th Rev Sheet No. 15	$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	17th Rev Sheet No. 32	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
250	TGP - Fuel Charge	ln 244 x ln 249	**$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**
252									
253									
254	**TGP Dracut**								
255	**Commodity Costs - NYMEX Price**	Ln 114	[redacted]						
256									
257	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
258	TGP - Trans Charge - ACA Rate - Z6-6	19th Rev Sheet No. 15	$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	17th Rev Sheet No. 32	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
261	TGP - Fuel Charge	ln 255 x ln 260	**$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.**										
2											
3	**Off Peak 2022 Summer Cost of Gas Filing**										
4	**NYMEX Futures @ Henry Hub**										May - Oct
5											Off Peak
6	For Month of:		Reference		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Strip Average
7		(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**										
9		Opening Prices		Line 206	$3.9770	$4.0110	$4.0520	$4.0580	$4.0420	$4.0720	$ 4.0353
10					$3.9770	$4.0110	$4.0520	$4.0580	$4.0420	$4.0720	$ 4.0353

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 20 - Oct 20 vs May 21 - Oct 21 - Residential Heating Rate R-3

November 1, 2021 - April 30, 2022 / **May 1, 2022 - October 31, 2022**
Residential Heating (R3)

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		62	110	123	148	132	92	667	51	28	16	14	14	21	144	811
	8/1/2021 - Current															
Winter:																
Cust. Chg	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 92.34								
Headblock	$ 0.5632	$ -	$ -	$ -	$ -	$ -	$ -	$ -								
Tailblock	$ 0.5632	$ 34.92	$ 61.95	$ 69.27	$ 83.35	$ 74.34	$ 51.81	$ 375.65								
HB Threshold	-															
Summer:	8/1/2021 - Current															
Cust. Chg	$ 15.39								$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 92.34	$ 184.68
Headblock	$ 0.5632								$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.5632								$ 28.72	$ 15.77	$ 9.01	$ 7.88	$ 7.88	$ 11.83	$ 81.10	$ 456.76
HB Threshold	-															
Total Base Rate Amount		$ 50.31	$ 77.34	$ 84.66	$ 98.74	$ 89.73	$ 67.20	$ 467.99	$ 44.11	$ 31.16	$ 24.40	$ 23.27	$ 23.27	$ 27.22	$ 173.44	$ 641.44
COG Rate - (Seasonal)		$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 1.0318
COG amount		$ 70.30	$ 124.73	$ 139.47	$ 167.82	$ 149.67	$ 104.32	$ 756.31	$ 28.49	$ 15.64	$ 8.94	$ 7.82	$ 7.82	$ 11.73	$ 80.45	$ 836.76
LDAC		$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444
LDAC amount		$ 8.95	$ 15.89	$ 17.76	$ 21.37	$ 19.06	$ 13.29	$ 96.33	$ 7.37	$ 4.04	$ 2.31	$ 2.02	$ 2.02	$ 3.03	$ 20.80	$ 117.13
Total Bill		**$ 129.56**	**$ 217.96**	**$ 241.90**	**$ 287.94**	**$ 258.47**	**$ 184.81**	**$ 1,320.63**	**$ 79.97**	**$ 50.85**	**$ 35.65**	**$ 33.12**	**$ 33.12**	**$ 41.98**	**$ 274.69**	**$ 1,595.32**

November 1, 2020 - April 30, 2021 / **May 1, 2021 - October 31, 2021**
Residential Heating (R3)

			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			62	110	123	148	132	92	667	51	28	16	14	14	21	144	811
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 15.50	$ 15.39	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 93.00								
Headblock	$ 0.5678	$ 0.5632	$ -	$ -	$ -	$ -	$ -	$ -	$ -								
Tailblock	$ 0.5678	$ 0.5632	$ 35.20	$ 62.46	$ 69.84	$ 84.03	$ 74.95	$ 52.24	$ 378.72								
HB Threshold	-	-	$ 34.53														
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 15.50	$ 15.39								$15.50	$15.50	$15.50	$15.39	$15.39	$15.39	$ 92.67	$ 185.67
Headblock	$ 0.5678	$ 0.5632								$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.5678	$ 0.5632								$ 28.96	$ 15.90	$ 9.08	$ 7.88	$ 7.88	$ 11.83	$ 81.54	$ 460.26
HB Threshold	-	-															
Total Base Rate Amount			$ 50.70	$ 77.96	$ 85.34	$ 99.53	$ 90.45	$ 67.74	$ 471.72	$ 44.46	$ 31.40	$ 24.58	$ 23.27	$ 23.27	$ 27.22	$ 174.21	$ 645.93
COG Rate - (Seasonal)			$ 0.5571	$ 0.5571	$ 0.4664	$ 0.4276	$ 0.5156	$ 0.6050	$ 0.5100	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.4893
COG amount			$ 34.54	$ 61.28	$ 57.37	$ 63.28	$ 68.06	$ 55.66	$ 340.19	$ 20.07	$ 11.02	$ 6.30	$ 5.51	$ 5.51	$ 8.26	$ 56.66	$ 396.86
LDAC			$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589
LDAC amount			$ 3.65	$ 6.48	$ 7.24	$ 8.72	$ 7.77	$ 5.42	$ 39.29	$ 3.00	$ 1.65	$ 0.94	$ 0.82	$ 0.82	$ 1.24	$ 8.48	$ 47.77
Total Bill			**$ 88.90**	**$ 145.72**	**$ 149.95**	**$ 171.54**	**$ 166.28**	**$ 128.82**	**$ 851.20**	**$ 67.53**	**$ 44.07**	**$ 31.82**	**$ 29.61**	**$ 29.61**	**$ 36.72**	**$ 239.35**	**$ 1,090.55**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$ 40.67**	**$ 72.24**	**$ 91.95**	**$ 116.40**	**$ 92.19**	**$ 55.99**	**$ 469.43**	**$ 12.44**	**$ 6.78**	**$ 3.83**	**$ 3.51**	**$ 3.51**	**$ 5.27**	**$ 35.34**	**$ 504.77**
% Change	**45.75%**	**49.57%**	**61.32%**	**67.86%**	**55.44%**	**43.47%**	**55.15%**	**18.42%**	**15.39%**	**12.03%**	**11.86%**	**11.86%**	**14.34%**	**14.76%**	**46.29%**
Base Rate	$ (0.40)	$ (0.62)	$ (0.68)	$ (0.79)	$ (0.72)	$ (0.53)	$ (3.73)	$ (0.34)	$ (0.24)	$ (0.18)	$ -	$ -	$ -	$ (0.77)	$ (4.50)
% Change	-0.78%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%	-0.78%	-0.76%	-0.75%	0.00%	0.00%	0.00%	-0.44%	-0.70%
COG & LDAC	$ 41.06	$ 72.86	$ 92.62	$ 117.19	$ 92.90	$ 56.53	$ 473.16	$ 12.79	$ 7.02	$ 4.01	$ 3.51	$ 3.51	$ 5.27	$ 36.10	$ 509.26
% Change	107.52%	107.52%	143.35%	162.76%	122.51%	92.55%	124.69%	55.42%	55.42%	55.42%	55.42%	55.42%	55.42%	55.42%	114.54%
check	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.00)	$ -	$ -	$ -	$ -	$ -	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-41

November 1, 2021 - April 30, 2022 / **May 1, 2022 - October 31, 2022**
Commercial Rate (G-41)

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		89	277	504	457	331	297	1,955	153	39	26	34	25	29	306	2,261
Winter:	8/1/2021 - Current															
Cust. Chg	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 342.36								
Headblock	$ 0.4688	$ 41.72	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 276.12								
Tailblock	$ 0.3149	$ -	$ 55.74	$ 127.22	$ 112.42	$ 72.74	$ 62.04	$ 430.15								
HB Threshold	100	$41.93	$46.88	$46.88	$46.88	$46.88	$46.88									
Summer:	8/1/2021 - Current															
Cust. Chg	$ 57.06								$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 342.36	$ 684.72
Headblock	$ 0.4688								$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 56.26	$ 332.38
Tailblock	$ 0.3149								$ 41.88	$ 5.98	$ 1.89	$ 4.41	$ 1.57	$ 2.83	$ 58.57	$ 488.72
HB Threshold	20															
Total Base Rate Amount		$ 98.78	$ 159.68	$ 231.16	$ 216.36	$ 176.68	$ 165.98	$ 1,048.64	$ 108.32	$ 72.42	$ 68.33	$ 70.84	$ 68.01	$ 69.27	$ 457.19	$ 1,505.82
COG Rate - (Seasonal)		$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 1.0563
COG amount		$ 100.93	$ 314.15	$ 571.59	$ 518.28	$ 375.39	$ 336.83	$ 2,217.17	$ 85.57	$ 21.81	$ 14.54	$ 19.02	$ 13.98	$ 16.22	$ 171.15	$ 2,388.31
LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount		$ 7.81	$ 24.32	$ 44.25	$ 40.13	$ 29.06	$ 26.08	$ 171.66	$ 13.43	$ 3.42	$ 2.28	$ 2.99	$ 2.20	$ 2.55	$ 26.87	$ 198.53
Total Bill		**$ 207.53**	**$ 498.15**	**$ 847.00**	**$ 774.77**	**$ 581.13**	**$ 528.88**	**$ 3,437.46**	**$ 207.33**	**$ 97.66**	**$ 85.15**	**$ 92.85**	**$ 84.19**	**$ 88.04**	**$ 655.20**	**$ 4,092.67**

November 1, 2020 - April 30, 2021 / **May 1, 2021 - October 31, 2021**
Commercial Rate (G-41)

	7/1/20 - 7/31/21	8/1/2021 - Current	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			89	277	504	457	331	297	1,955	153	39	26	34	25	29	306	2,261
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 57.46	$ 57.06	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 344.76								
Headblock	$ 0.4711	$ 0.4688	$ 41.93	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 277.48								
Tailblock	$ 0.3165	$ 0.3149	$ -	$ 56.02	$ 127.87	$ 112.99	$ 73.11	$ 62.35	$ 432.34								
HB Threshold	100	100															
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 57.46	$ 57.06								$57.46	$ 57.46	$ 57.46	$ 57.06	$ 57.06	$ 57.06	$ 343.56	$ 688.32
Headblock	$ 0.4711	$ 0.4688								$ 9.42	$ 9.42	$ 9.42	$ 9.38	$ 9.38	$ 9.38	$ 56.39	$ 333.87
Tailblock	$ 0.3165	$ 0.3149								$ 42.09	$ 6.01	$ 1.90	$ 4.41	$ 1.57	$ 2.83	$ 58.82	$ 491.16
HB Threshold	20	20															
Total Base Rate Amount			$ 99.39	$ 160.59	$ 232.44	$ 217.56	$ 177.68	$ 166.92	$ 1,054.58	$ 108.98	$ 72.90	$ 68.78	$ 70.84	$ 68.01	$ 69.27	$ 458.78	$ 1,513.36
COG Rate - (Seasonal)			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$ 0.5018	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.4865
COG amount			$ 49.41	$ 153.79	$ 234.11	$ 194.54	$ 170.03	$ 179.12	$ 981.01	$ 59.46	$ 15.16	$ 10.10	$ 13.21	$ 9.72	$ 11.27	$ 118.91	$ 1,099.92
LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount			$ 4.94	$ 15.37	$ 27.97	$ 25.36	$ 18.37	$ 16.48	$ 108.50	$ 8.49	$ 2.16	$ 1.44	$ 1.89	$ 1.39	$ 1.61	$ 16.98	$ 125.49
Total Bill			**$ 153.74**	**$ 329.75**	**$ 494.52**	**$ 437.47**	**$ 366.09**	**$ 362.52**	**$ 2,144.09**	**$ 176.92**	**$ 90.22**	**$ 80.33**	**$ 85.94**	**$ 79.11**	**$ 82.15**	**$ 594.67**	**$ 2,738.76**
DIFFERENCE:																	
Total Bill			**$ 53.79**	**$ 168.39**	**$ 352.48**	**$ 337.30**	**$ 215.05**	**$ 166.36**	**$ 1,293.37**	**$ 30.40**	**$ 7.44**	**$ 4.82**	**$ 6.90**	**$ 5.08**	**$ 5.89**	**$ 60.53**	**$ 1,353.90**
% Change			**34.99%**	**51.07%**	**71.28%**	**77.10%**	**58.74%**	**45.89%**	**60.32%**	**17.18%**	**8.25%**	**6.00%**	**8.03%**	**6.42%**	**7.17%**	**10.18%**	**49.43%**
Base Rate			$ (0.60)	$ (0.91)	$ (1.28)	$ (1.20)	$ (1.00)	$ (0.95)	$ (5.94)	$ (0.66)	$ (0.48)	$ (0.46)	$ -	$ -	$ -	$ (1.59)	$ (7.53)
% Change			-0.61%	-0.57%	-0.55%	-0.55%	-0.56%	-0.57%	-0.56%	-0.60%	-0.65%	-0.66%	0.00%	0.00%	0.00%	-0.35%	-0.50%
COG & LDAC			$ 54.40	$ 169.30	$ 353.76	$ 338.50	$ 216.05	$ 167.30	$ 1,299.31	$ 31.06	$ 7.92	$ 5.28	$ 6.90	$ 5.08	$ 5.89	$ 62.12	$ 1,361.43
% Change			100.08%	100.08%	134.98%	153.93%	114.67%	85.53%	119.26%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	111.10%
check			$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 0.00	$ 0.00	$ (0.00)	$ (0.00)	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-42

November 1, 2021 - April 30, 2022 / **May 1, 2022 - October 31, 2022**
C&I High Winter Use Medium G-42

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		830	2,189	3,708	3,406	2,603	2,395	15,131	1,319	484	285	247	269	340	2,944	18,075
Winter:	8/1/2021 - Current															
Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14								
Headblock	$ 0.4261	$ 353.66	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 2,484.16								
Tailblock	$ 0.2839	$ -	$ 337.56	$ 768.80	$ 683.06	$ 455.09	$ 396.04	$ 2,640.55								
HB Threshold	1,000															
Summer:	8/1/2021 - Current															
Cust. Chg	$ 171.19								$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14	$ 2,054.28
Headblock	$ 0.4261								$ 170.44	$ 170.44	$ 121.44	$ 105.25	$ 114.62	$ 144.87	$ 827.06	$ 3,311.22
Tailblock	$ 0.2839								$ 260.90	$ 23.85	$ -	$ -	$ -	$ -	$ 284.75	$ 2,925.31
HB Threshold	400															
Total Base Rate Amount		$ 524.85	$ 934.85	$ 1,366.09	$ 1,280.35	$ 1,052.38	$ 993.33	$ 6,151.86	$ 602.53	$ 365.48	$ 292.63	$ 276.44	$ 285.81	$ 316.06	$ 2,138.95	$ 8,290.81
COG Rate - (Seasonal)		$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 1.0405
COG amount		$ 941.30	$ 2,482.54	$ 4,205.24	$ 3,862.74	$ 2,952.06	$ 2,716.17	$ 17,160.07	$ 737.72	$ 270.70	$ 159.40	$ 138.15	$ 150.45	$ 190.16	$ 1,646.58	$ 18,806.65
LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount		$ 72.88	$ 192.21	$ 325.59	$ 299.07	$ 228.56	$ 210.30	$ 1,328.61	$ 115.82	$ 42.50	$ 25.02	$ 21.69	$ 23.62	$ 29.85	$ 258.50	$ 1,587.11
Total Bill		**$ 1,539.04**	**$ 3,609.60**	**$ 5,896.92**	**$ 5,442.17**	**$ 4,233.01**	**$ 3,919.80**	**$ 24,640.53**	**$ 1,456.07**	**$ 678.68**	**$ 477.05**	**$ 436.27**	**$ 459.88**	**$ 536.08**	**$ 4,044.03**	**$ 28,684.57**

November 1, 2020 - April 30, 2021 / **May 1, 2021 - October 31, 2021**
C&I High Winter Use Medium G-42

			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			830	2,189	3,708	3,406	2,603	2,395	15,131	1,319	484	285	247	269	340	2,944	18,075
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34								
Headblock	$ 0.4284	$ 0.4261	$ 355.57	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 2,497.57								
Tailblock	$ 0.2855	$ 0.2839	$ -	$ 339.46	$ 773.13	$ 686.91	$ 457.66	$ 398.27	$ 2,655.44								
HB Threshold	1,000	1,000															
	-	-															
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 172.39	$ 171.19								$ 172.39	$ 172.39	$ 172.39	$ 171.19	$ 171.19	$ 171.19	$ 1,030.74	$ 2,065.08
Headblock	$ 0.4284	$ 0.4261								$ 171.36	$ 171.36	$ 122.09	$ 105.25	$ 114.62	$ 144.87	$ 829.56	$ 3,327.13
Tailblock	$ 0.2855	$ 0.2839								$ 262.37	$ 23.98	$ -	$ -	$ -	$ -	$ 286.36	$ 2,941.79
HB Threshold	400	400															
Total Base Rate Amount			$ 527.96	$ 940.25	$ 1,373.92	$ 1,287.70	$ 1,058.45	$ 999.06	$ 6,187.35	$ 606.12	$ 367.73	$ 294.48	$ 276.44	$ 285.81	$ 316.06	$ 2,146.65	$ 8,334.00
COG Rate - (Seasonal)			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$ 0.5043	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.4854
COG amount			$ 460.82	$ 1,215.33	$ 1,722.37	$ 1,449.93	$ 1,337.16	$ 1,444.42	$ 7,630.03	$ 512.56	$ 188.08	$ 110.75	$ 95.98	$ 104.53	$ 132.12	$ 1,144.04	$ 8,774.07
LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount			$ 46.07	$ 121.49	$ 205.79	$ 189.03	$ 144.47	$ 132.92	$ 839.77	$ 73.20	$ 26.86	$ 15.82	$ 13.71	$ 14.93	$ 18.87	$ 163.39	$ 1,003.16
Total Bill			**$ 1,034.84**	**$ 2,277.07**	**$ 3,302.08**	**$ 2,926.67**	**$ 2,540.07**	**$ 2,576.41**	**$ 14,657.15**	**$ 1,191.89**	**$ 582.68**	**$ 421.05**	**$ 386.13**	**$ 405.27**	**$ 467.06**	**$ 3,454.08**	**$ 18,111.24**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$ 504.19**	**$ 1,332.53**	**$ 2,594.84**	**$ 2,515.50**	**$ 1,692.93**	**$ 1,343.39**	**$ 9,983.38**	**$ 264.18**	**$ 96.00**	**$ 56.00**	**$ 50.14**	**$ 54.61**	**$ 69.02**	**$ 589.95**	**$ 10,573.33**
% Change	**48.72%**	**58.52%**	**78.58%**	**85.95%**	**66.65%**	**52.14%**	**68.11%**	**22.16%**	**16.48%**	**13.30%**	**12.99%**	**13.47%**	**14.78%**	**17.08%**	**58.38%**
Base Rate	$ (3.11)	$ (5.40)	$ (7.83)	$ (7.35)	$ (6.06)	$ (5.73)	$ (35.49)	$ (3.59)	$ (2.25)	$ (1.86)	$ -	$ -	$ -	$ (7.70)	$ (43.19)
% Change	-0.59%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.59%	-0.61%	-0.63%	0.00%	0.00%	0.00%	-0.36%	-0.52%
COG & LDAC	$ 507.30	$ 1,337.93	$ 2,602.67	$ 2,522.85	$ 1,699.00	$ 1,349.12	$ 10,018.87	$ 267.77	$ 98.26	$ 57.86	$ 50.14	$ 54.61	$ 69.02	$ 597.65	$ 10,616.52
% Change	100.08%	100.08%	134.98%	153.93%	114.67%	85.53%	118.29%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	108.58%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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**

7 **November 1, 2021 - April 30, 2022** | **May 1, 2022 - October 31, 2022**
8 **Commercial Rate (G-52)**

Row		Rate	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
11	**Typical Usage (Therms)**		1,352	1,866	2,284	2,160	1,886	1,760	11,308	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
13	**Winter:**	8/1/2021 - Current															
14	Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14								
15	Headblock	$ 0.2428	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 1,456.80								
16	Tailblock	$ 0.1617	$ 56.92	$ 140.03	$ 207.62	$ 187.57	$ 143.27	$ 122.89	$ 858.30								
17	HB Threshold	1,000															
19	**Summer:**	8/1/2021 - Current															
20	Cust. Chg	$ 171.19								$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14	$ 2,054.28
21	Headblock	$ 0.1749								$ 174.90	$ 174.90	$ 174.90	$ 174.90	$ 174.90	$ 156.89	$ 1,031.39	$ 2,488.19
22	Tailblock	$ 0.1000								$ 49.70	$ 12.80	$ 3.20	$ 2.50	$ 5.00	$ -	$ 73.20	$ 931.50
23	HB Threshold	1,000															
25	Total Base Rate Amount		$ 470.91	$ 554.02	$ 621.61	$ 601.56	$ 557.26	$ 536.88	$ 3,342.24	$ 395.79	$ 358.89	$ 349.29	$ 348.59	$ 351.09	$ 328.08	$ 2,131.73	$ 5,473.97
27	COG Rate - (Seasonal)		$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.9201
28	COG amount		$ 1,531.00	$ 2,113.06	$ 2,586.40	$ 2,445.98	$ 2,135.71	$ 1,993.02	$ 12,805.18	$ 835.33	$ 629.42	$ 575.86	$ 571.95	$ 585.90	$ 500.53	$ 3,698.98	$ 16,504.16
30	LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 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	$ 131.45	$ 99.05	$ 90.62	$ 90.00	$ 92.20	$ 78.76	$ 582.07	$ 1,574.99
33	**Total Bill**		**$ 2,120.63**	**$ 2,830.93**	**$ 3,408.57**	**$ 3,237.21**	**$ 2,858.57**	**$ 2,684.45**	**$ 17,140.34**	**$ 1,362.56**	**$ 1,087.36**	**$ 1,015.76**	**$ 1,010.54**	**$ 1,029.19**	**$ 907.36**	**$ 6,412.78**	**$ 23,553.12**

35 **November 1, 2020 - April 30, 2021** | **May 1, 2021 - October 31, 2021**
36 **Commercial Rate (G-52)**

Row		Rate	Rate	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
39	**Typical Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,308	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
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	$ 172.39	$ 172.39	$ 1,034.34								
43	Headblock	$ 0.2439	$ 0.2428	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 1,463.40								
44	Tailblock	$ 0.1624	$ 0.1617	$ 57.16	$ 140.64	$ 208.52	$ 188.38	$ 143.89	$ 123.42	$ 862.02								
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								$ 172.39	$ 172.39	$ 172.39	$ 171.19	$ 171.19	$ 171.19	$ 1,030.74	$ 2,065.08
49	Headblock	$ 0.1767	$ 0.1749								$ 176.70	$ 176.70	$ 176.70	$ 174.90	$ 174.90	$ 156.89	$ 1,036.79	$ 2,500.19
50	Tailblock	$ 0.1004	$ 0.1000								$ 49.90	$ 12.85	$ 3.21	$ 2.50	$ 5.00	$ -	$ 73.46	$ 935.48
51	HB Threshold	1,000	1,000															
53	Total Base Rate Amount			$ 473.45	$ 556.93	$ 624.81	$ 604.67	$ 560.18	$ 539.71	$ 3,359.76	$ 398.99	$ 361.94	$ 352.30	$ 348.59	$ 351.09	$ 328.08	$ 2,140.99	$ 5,500.75
55	COG Rate - (Seasonal)			$ 0.5660	$ 0.5660	$ 0.4753	$ 0.4365	$ 0.5245	$ 0.6139	$ 0.5235	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.4778
56	COG amount			$ 765.23	$ 1,056.16	$ 1,085.59	$ 942.84	$ 989.21	$ 1,080.46	$ 5,919.48	$ 598.65	$ 451.09	$ 412.70	$ 409.90	$ 419.90	$ 358.71	$ 2,650.94	$ 8,570.42
58	LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 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	$ 83.08	$ 62.60	$ 57.28	$ 56.89	$ 58.28	$ 49.78	$ 367.91	$ 995.50
61	**Total Bill**			**$ 1,313.72**	**$ 1,716.65**	**$ 1,837.16**	**$ 1,667.39**	**$ 1,654.06**	**$ 1,717.86**	**$ 9,906.84**	**$ 1,080.72**	**$ 875.63**	**$ 822.28**	**$ 815.38**	**$ 829.26**	**$ 736.57**	**$ 5,159.83**	**$ 15,066.67**

63 **DIFFERENCE:**

Row		Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
64	**Total Bill**	**$ 806.91**	**$ 1,114.28**	**$ 1,571.41**	**$ 1,569.82**	**$ 1,204.51**	**$ 966.59**	**$ 7,233.51**	**$ 281.84**	**$ 211.73**	**$ 193.49**	**$ 195.17**	**$ 199.93**	**$ 170.80**	**$ 1,252.95**	**$ 8,486.45**
65	% Change	**61.42%**	**64.91%**	**85.53%**	**94.15%**	**72.82%**	**56.27%**	**73.02%**	**26.08%**	**24.18%**	**23.53%**	**23.94%**	**24.11%**	**23.19%**	**24.28%**	**56.33%**
67	**Base Rate**	$ (2.55)	$ (2.91)	$ (3.20)	$ (3.11)	$ (2.92)	$ (2.83)	$ (17.52)	$ (3.20)	$ (3.05)	$ (3.01)	$ -	$ -	$ -	$ (9.26)	$ (26.78)
68	% Change	-0.54%	-0.52%	-0.51%	-0.51%	-0.52%	-0.52%	-0.52%	-0.80%	-0.84%	-0.86%	0.00%	0.00%	0.00%	-0.43%	-0.49%
70	**COG & LDAC**	$ 809.45	$ 1,117.19	$ 1,574.61	$ 1,572.93	$ 1,207.43	$ 969.42	$ 7,251.02	$ 285.04	$ 214.78	$ 196.50	$ 195.17	$ 199.93	$ 170.80	$ 1,262.21	$ 8,513.23
71	% Change	96.33%	96.33%	129.88%	148.01%	110.38%	82.28%	110.75%	41.81%	41.81%	41.81%	41.81%	41.81%	41.81%	41.81%	89.00%
	check	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
<u>Residential Heating</u>

	Summer 2021	Summer 2022
Customer Charge	$ 15.50	$ 15.39
First 20 Therms	$ 0.5678	$ 0.5632
Excess 20 Therms	$ 0.5678	$ 0.5632
LDAC	$ 0.0589	$ 0.1444
COG	$ 0.5587	$ 0.5587
Total Adjust	$ 0.6176	$ 0.7031

				Total		Base Rate		COG		LDAC	
		Summer 2021 COG @	Summer 2022 Cog @	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**
		$ 0.6176	$ 0.7031	$ 0.09	14%						
Cooking alone	5	$ 21.43	$ 21.72	$ 0.29	1%	$ (0.13)	-1%	$ -	0%	$ 0.43	2%
	10	$ 27.35	$ 28.05	$ 0.70	3%	$ (0.16)	-1%	$ -	0%	$ 0.86	3%
	20	$ 39.21	$ 40.72	$ 1.51	4%	$ (0.20)	-1%	$ -	0%	$ 1.71	4%
Water Heating alone	30	$ 51.06	$ 53.38	$ 2.32	5%	$ (0.25)	0%	$ -	0%	$ 2.57	5%
	45	$ 68.84	$ 72.37	$ 3.53	5%	$ (0.32)	0%	$ -	0%	$ 3.85	6%
	50	$ 74.77	$ 78.71	$ 3.94	5%	$ (0.34)	0%	$ -	0%	$ 4.28	6%
Heating Alone	80	$ 104.41	$ 110.36	$ 5.96	6%	$ (0.45)	0%	$ -	0%	$ 6.41	6%
	125	$ 173.16	$ 183.81	$ 10.65	6%	$ (0.72)	0%	$ -	0%	$ 11.37	7%
	150	$ 193.31	$ 205.34	$ 12.03	6%	$ (0.80)	0%	$ -	0%	$ 12.83	7%
	200	$ 252.58	$ 268.65	$ 16.07	6%	$ (1.03)	0%	$ -	0%	$ 17.10	7%

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Updated Schedule 10A
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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 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
a The base use portion of the class design day demand based on base use
b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

		Column A	**Column B**	**Column C**	**Column D**	**Column E**	**Column F**
		Design Day Demand. 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	**42.607%**		3,719	69,396
14	LLF Total	75,211	82,510	**48.083%**		2,626	79,885
15	HLF Total	14,903	15,977	**9.310%**		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					**100.0%**	**100.0%**
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	**42.607%**	615,228	4,506	$11.3770
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.607%**	6,348,623	46,502	$11.3770
48	Storage	Line 40 * Line 13 Col C	**42.607%**	1,755,962	11,979	$12.2156
49	Peaking	Line 41 * Line 13 Col C	**42.607%**	1,754,952	10,127	$14.4412
50	Total		**42.607%**	10,474,751	73,114	$11.9388
51						

52	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**						Updated Schedule 10A
53							Page 2 of 3
54	**2022 Summer Cost of Gas Filing**						
55	**Capacity Assignment Calculations 2020-2021**						
56	**Derivation of Class Assignments and Weightings**						
57							
58							**Ratios for COG**
59	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
60	Pipeline - Base	Line 38 - Line 46		828,730	6,070	$11.3770	
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		2,364,048	13,642	$14.4410	
64	Total		**57.393%**	14,109,870	98,488	$11.9388	**1.0000**
65							
66							
67	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
68	Pipeline - Base	Line 60 * Line 24 Col E		317,329	2,324	$11.3787	
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		2,061,026	11,893	$14.4415	
72	Total		**48.3884%**	11,896,104	82,895	$11.9590	**1.0017**
73			38.291%	84%			(Line 72 / Line 64)
74							
75	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
76	Pipeline - Base	Line 60 - Line 68		511,401	3,746	$11.3766	
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		303,022	1,749	$14.4379	
80	Total		**9.0047%**	2,213,767	15,593	$11.8310	**0.9910**
81							(Line 80 / Line 64)
82							

		Residential	LLF C&I	HLF C&I	Total
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%	**68.68%**	**75.52%**	
94	Storage	16.38%	**16.97%**	**13.26%**	
95	Peaking	13.85%	**14.35%**	**11.22%**	
96	Total	100.00%	**100.00%**	**100.00%**	
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%

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Updated Schedule 10A
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2022 Summer Cost of Gas Filing
Correction Factor Calculation

	d	e	f	g	h	i	
Data Source: Schedule 10B	May	June	July	Aug	Sep	Oct	Total Sales
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
Gross Total	2,351,710	1,317,770	1,170,750	1,179,990	1,557,120	2,864,780	10,442,120

Total Sales	10,442,120	
Low Winter Use	4,333,380	
Summer Ratio for Low Winter Use	**0.9910**	**Schedule 10A p 2, ln 80**
High Winter Use	6,108,740	
Summer Ratio for High Winter Use	**1.0017**	**Schedule 10A p 2, ln 72**

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

Correction Factor = **100.2748%**

Allocation Calculation for Miscellaneous Overhead

Projected Winter Sales Volume	11/1/21- 4/30/22	91,676,680	Sch.10B, ln 23
Projected Annual Sales Volume	11/1/21 - 10/31/22	115,042,810	Sch.10B, ln 23
Percentage of Winter Sales to Annual Sales		79.69%	

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

U[dated Schedule 10B
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Dry Therms

							Subtotal							Subtotal	
Firm Sales	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**PK 21-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**OP 22**	**Total**
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
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
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
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
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
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
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
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
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
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
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
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
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**
Transportation Sales															
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
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
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
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
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
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
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
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**
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**

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Updated Schedule 11A**
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Off Peak 2022 Summer Cost of Gas Filing
Normal and Design Year Volumes

Volumes (Therms) **Normal Year**

For the Months of May 22 -October 22

	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

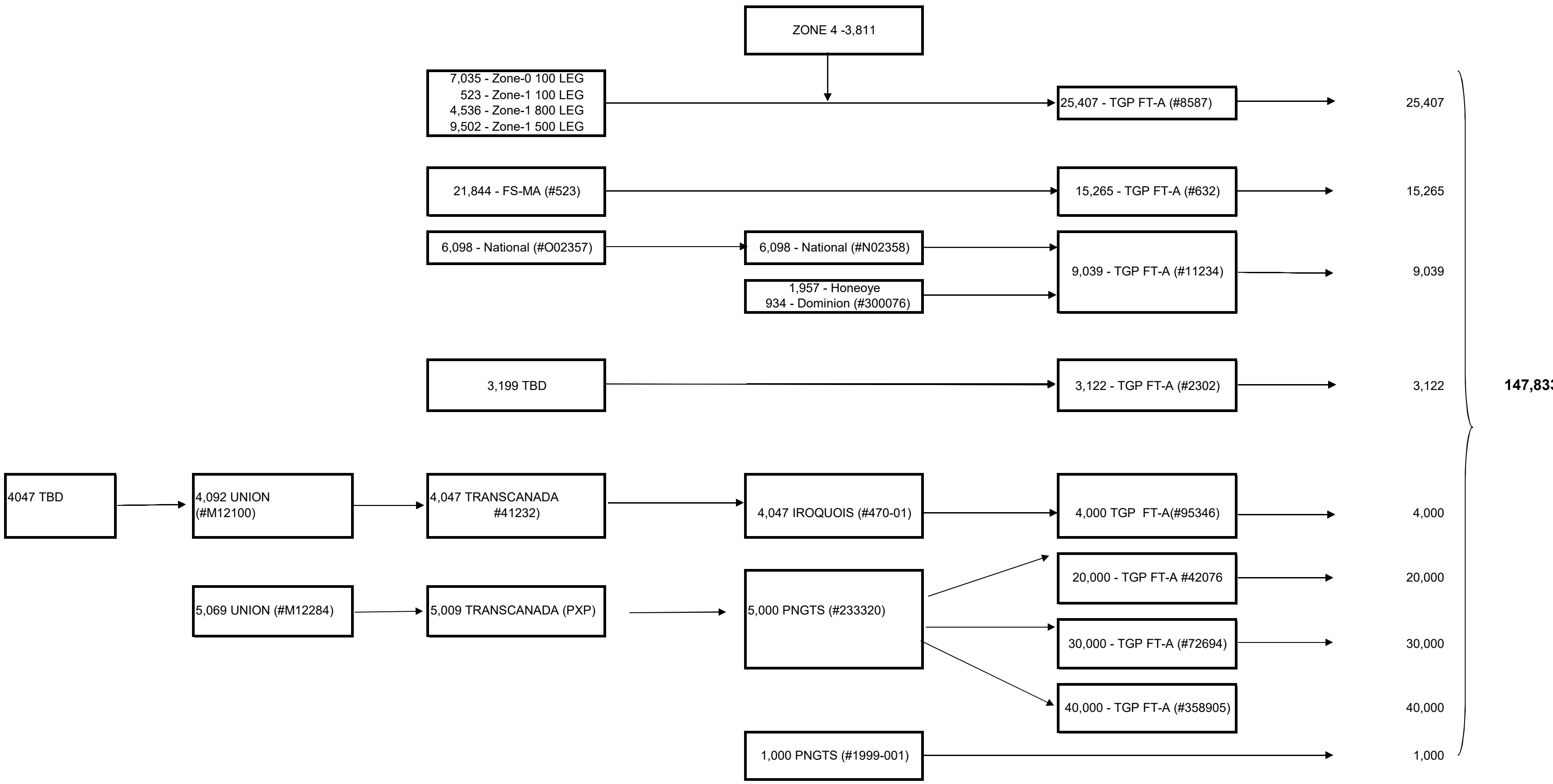
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**							**Updated Schedule 11B**
2								**Page 1 of 1**
3	**Off Peak 2022 Summer Cost of Gas Filing**							
44	**Normal and Design Year Volumes**							
45								
46								
47	**Volumes (Therms)**	**Design Year**						
48								
49	**For the Months of May 22 -October 22**							
50								
51								**Off Peak**
52		**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**May - Oct**
53	Pipeline Gas:							
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.** — Updated Schedule 11C
2
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Capacity Utilization**
5 **Volumes (Therms)**
6

Line		Off-Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Off-Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
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			
32									
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)			
39									
40	Total Sendout Volumes	22,950,820				22,928,033			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



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.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing

Storage Inventory

Underground Storage Gas

Ln	Description	Reference	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Estimate)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Total
9	Beginning Balance (MMBtu)		1,895,479	1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	1,951,935
11	Injections (MMBtu)	Sch 11A ln 39 /10	11,436	27,746	-	-	184,117	184,117	1,961,830
13	Subtotal		1,906,915	1,929,391	1,929,241	1,929,241	2,113,358	2,297,475	
15	Storage Sale		-	-	-	-	-	-	
17	Withdrawals (MMBtu)	Sch 11A ln 29 /10	(5,270)	(150)	-	-	-	-	(1,368,064)
19	Ending Balance (MMBtu)		1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	2,297,475	2,545,701
22	Beginning Balance		$ 9,092,272	$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 3,609,668
24	Injections	ln 11 * ln 36	18,859	78,943	-	-	608,069	612,500	6,786,402
26	Subtotal		$ 9,111,130	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 10,385,463	
28	Storage Sale		$ -	$ -	$ -	$ -	$ -	$ -	
30	Withdrawals	ln 17 * ln 34	$ (25,180)	$ -	$ -	$ -	$ -	$ -	$ (2,634,626)
32	Ending Balance		$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 10,385,463	$ 7,761,444
34	Average Rate For Withdrawals	ln 22 /ln 9	$ 4.7779	$ 4.7501	$ 4.7505	$ 4.7505	$ 4.6244	$ 4.5204	
36	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.** Updated Schedule 13
38 Page 2 of 3
39 **Off Peak 2022 Summer Cost of Gas Filing**
40
41 **Liquid Propane Gas (LPG)**

Ln			May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
43			(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
44	Beginning Balance		93,824	93,828	94,844	94,844	94,844	94,844	96,655
46	Injections	Sch 11A ln 38 /10	72	1,016	-	-	-	-	49,431
48	Subtotal		93,896	94,844	94,844	94,844	94,844	94,844	
50	Withdrawals	Sch 11A ln 33 /10	(68)	-	-	-	-	-	(61,632)
52	Adjustment for change in temperature		-	-	-	-	-	-	-
53	Adjustment for Transfer		-	-	-	-	-	-	-
54	Ending Balance		93,828	94,844	94,844	94,844	94,844	94,844	84,454
57	Beginning Balance		$ 1,382,938	$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,193,497
59	Injections	ln 46 * ln 69	1,061	13,101	-	-	-	-	168,840
61	Subtotal		$ 1,384,000	$ 1,396,098	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	
63	Withdrawals	ln 52 * ln 67	(1,002)	-	10,676	-	-	-	(763,126)
65	Ending Balance		$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 599,211
67	Average Rate For Withdrawals		$ 14.7397	$ 14.7199	$ 14.7199	$ 14.8325	$ 14.8325	$ 14.8325	
69	Propane Rate for Injections	Actual or Sch. 6, ln 162 * 10	$ -	$ -	$ -	$ -	$ -	$ -	

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

Updated Schedule 13
Page 3 of 3

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

Ln	Liquid Natural Gas (LNG)		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
78	Injections	Sch 11A ln 37 /10	797	6,395	-	-	-	-	136,806
80	Subtotal		8,682	12,323	10,583	10,583	10,583	10,583	
82	Withdrawals	Sch 11A ln 32 /10	(2,754)	(1,740)	-	-	-	-	(132,648)
84	Ending Balance		5,928	10,583	10,583	10,583	10,583	10,583	16,216
87	Beginning Balance		$ 34,430	$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 135,659
89	Injections	ln 78 * ln 99	3,480	24,011	-	-	-	-	653,097
91	Subtotal		$ 37,910	$ 49,896	$ 42,850	$ 42,850	$ 42,850	$ 42,850	
93	Withdrawals	ln 82 * ln 97	(12,025)	(7,045)	-	-	-	-	(825,208)
95	Ending Balance		$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ (36,451)
97	Average Rate For Withdrawals		$ 4.3665	$ 4.0490	$ 4.0490	$ 4.0490	$ 4.0490	$ 4.0490	
99	LNG Rate for Injections	Actual or Sch. 6, ln 161 * 10	$ 4.3665	$ 3.7546	$ 11.2630	$ 11.1000	$ -	$ -	

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 RATE	WINTER IMPACT	SUMMER RATE	SUMMER IMPACT
Original Filing Residential COG Rates excluding GAP – R-4	**$ 0.9056**		**$ 0.5002**	
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
Total Rate Change		**$ 0.2283**		**$ 0.5587**
Original Filing Residential GAP COG Rates – R-4	**$ 0.4981**		**$ 0.5002**	
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
Total Rate Change		**$ 0.1255**		**$ 0.5887**
Original Filing G-4 rates	**$ 0.9058**		**$ 0.5007**	
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
Total Rate Change		**$ 0.2283**		**$ 0.5593**
Original Filing G-5 rates	**$ 0.9041**		**$ 0.4994**	
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
Total Rate Change		**$ 0.2283**		**$ 0.5580**

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

LDAC Adjustments		
Original Filing Total LDAC Rate	$ 0.1733	
Updated Filing Total LDAC Rate	$ 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	$ -
Total LDAC Rate Change		**$ (0.0289)**
Original Filing RDAF component of the Residential LDAC Rate	$ 0.0459	
Updated Filing RDAF component of the LDAC Rate, this impacts residential only	$ 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'		
Total LDAC Rate Change		**$ (0.0307)**
*This change resulted in a $0.0307 reduction in the LDAC rate and the RDAF Component of the LDAC rate		
Original Filing Environmental component of the LDAC Rate	$ 0.0155	
Updated Filing Environmental component of the LDAC Rate, this impacts both Residential and Commercial	$ 0.0155	$ -
Updated the environmental rate calculation to exclude the Blue Chip invoice for $1,062 identified in the Environmental Audit.		
Total Environmental Component Rate Change		**$ -**
*This change resulted in no change in the LDAC rate and the RDAF Component of the LDAC rate		
Original Filing GAP component of the LDAC Rate	$ 0.0138	
Updated Filing GAP component of the LDAC Rate	$ 0.0156	$ 0.0018
This component changed due to the changes in COG rates		
Total GAP component Rate Change		**$ 0.0018**
*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.		
Ties to total rate change for LDAC		

Schedule 1
Page 1 of 4

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

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

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

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

REDACTED

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
152	**D. Supply and Demand Costs by Source**										**REDACTED**
153											
154	Purchased Gas Demand Costs										
155	Pipeline Gas Demand Costs	lns 55 + 76	$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570		$ 9,738,885
156	Peaking Gas Demand Costs	ln 84	-	993,750	993,750	993,750	993,750	993,750	-		4,968,750
157	Subtotal Purchased Gas Demand Costs		$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570		$ 14,707,635
158	Less Capacity Credit	lns 56 + 77 + 85	(524,979)	(693,594)	(693,594)	(693,594)	(693,594)	(693,594)	(406,202)		(4,399,152)
159	Net Purchased Gas Demand Costs		$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368		$ 10,308,483
160											
161	Storage Gas Demand Costs										
162	Storage Demand	ln 96	$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317		$ 1,407,802
163	Less Capacity Credit	ln 97	(281,772)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)		(485,340)
164	Net Storage Demand Costs		$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389		$ 922,462
165											
166	**Total Demand Costs**	lns 159 + 164	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
167											
168	Purchased Gas Supply										
169	Commodity Costs	ln 118	$ -	$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499		$ 42,563,780
170	Less Storage Inj.(TGP Storage)	ln 131	[redacted]								
171	Less Storage Transportation	ln 132									
172	Less LNG Truck	ln 129									
173	Less Propane Truck	ln 130									
174	Plus Transportation Costs	ln 143									
175	Subtotal Purchased Gas Supply		$ -	$ 2,527,981	$ 8,837,950	$ 11,224,354	$ 10,752,485	$ 5,545,818	$ 2,138,024		$ 41,026,613
176											
177	Storage Commodity Costs										
178	Commodity Costs	ln 121	$ -	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894		$ 5,125,663
179	Transportation Costs	ln 145	-	25,361	60,588	75,479	75,113	54,742	449		291,733
180	Subtotal Storage Commodity Costs		$ -	$ 470,947	$ 1,125,101	$ 1,401,627	$ 1,394,830	$ 1,016,547	$ 8,344		$ 5,417,397
181											
182	Produced Gas Commodity Costs	ln 126	$ -	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567		$ 2,672,211
183											
184	**Subtotal Commodity Costs**	lns 175 + 180 + 182	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
185											
186	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
187											
188	**Total Commodity Costs**	lns 184 + 186	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
189											
190	**Total Demand Costs**	ln 102	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
191	**Total Supply Costs**	ln 188	-	3,013,068	10,121,153	14,458,463	12,777,150	6,591,451	2,154,935		49,116,221
192											
193	**Total Direct Gas Costs**	lns 190 + 191	$ 1,208,615	$ 4,801,183	$ 11,909,268	$ 16,246,578	$ 14,565,265	$ 8,379,566	$ 3,236,692		$ 60,347,167
194											
195							**REDACTED**				

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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**						
2							
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**						
4	**Contracts Ranked on a per Unit Cost Basis**						**Peak Period**
5					**Contract**	**Unit Dth**	**Cost per**
6	**Supplier**		**Contract**	**Contract Type**	**Unit**	**(MDQ/ACQ)**	**Unit Dth**
7	(a)		(b)	(c)	(d)	(e)	(f)
8							
9	**Demand Costs**						
10		ENGIE Demand FLS		Peaking	MDQ	3,000	[redacted]
11		Niagara Supply		Supply	MDQ	3,199	
12		Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
13		Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
14		National Fuel - Capacity Reservation	FSS-O02357	Storage	ACQ	670,800	
15		Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
16		Dominion - Demand	GSS 300076	Storage	MDQ	934	
17		National Fuel - Demand	FSS-O02357	Storage	MDQ	6,098	
18		National Fuel	FST N02358	Transportation	MDQ	6,098	
19		Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
20		Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
21		Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
22		Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
23		Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
24		Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
25		Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
26		Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
27		Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
28		Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
29		ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
30		TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	1,784	
31		Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
32		Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
33		Portland Natural Gas Trans Service	FTN-ENN0005	Transportation	MDQ	1,000	
34		Portland Natural Gas	FTN	Transportation	MDQ	1,784	
35		ENGIE Demand	NSB041	Peaking	MDQ	10,000	
36							
37	**Supply Costs - Commodity**						
38		TGP Supply (Z4)		Pipeline	Dkt	1,299,905	[redacted]
39		Niagara Supply		Pipeline	Dkt	398,527	
40		ENGIE COMBO		Pipeline	Dkt	417,491	
41		TGP Supply (Direct)		Pipeline	Dkt	1,618,368	
42		Dawn Supply		Pipeline	Dkt	480,704	
43		Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	
44		TGP Storage		Storage	Dkt	1,984,133	
45		PNGTS		Pipeline	Dkt	104,401	
46		Propane Truck		Pipeline	Dkt	44,755	
47		LNG Truck		Pipeline	Dkt	216,940	
48		Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	
49		Propane		Produced	Dkt	95,092	
50		LNG Vapor (Storage)		Produced	Dkt	219,916	
51							
52	**Supply Costs - Volumetric Transportation**						
53		Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	[redacted]
54		Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	
55		Niagara Supply		Pipeline	Dkt	398,527	
56		Dawn Supply		Pipeline	Dkt	480,704	
57		TGP Storage - Withdrawals		Pipeline	Dkt	1,984,133	
58		TGP Supply (Direct)		Pipeline	Dkt	1,618,368	

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

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

63 1/ Beginning Balance for Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
64 2/ Gas Cost Billed Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

Line																	
69			Prior Period Bal														
70			Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Peak Period
71		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
72	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	( )	(k)	(l)	(m)	(n)	(o)	(p)
74	**Account 1163 1422 Working Capital (Over)/Under Balance Interest Calculation**																
76	**Beginning Balance**	Account 1163-1422 1/	**$ 4,305**	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 4,305
78	Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
79	Prime Rate			4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
80	Forecast Working Capital	ln 34 * 0.091%		315	325	335	335	335	335	7,979	19,792	22,236	19,935	11,469	4,430	-	87,820
82	Projected Revenues w/o Int.	ln 119 * ln 123		-	-	-	-	-	-	(1,063)	(7,749)	(10,994)	(11,803)	(10,039)	(6,975)	(3,249)	(51,871)
83	Projected Unb lled Revenue									(4,615)	(6,734)	(7,810)	(6,816)	(5,474)	(3,240)		(34,688)
84	Reverse Prior Month Unbilled										4,615	6,734	7,810	6,816	5,474	3,240	34,688
86	Add Net Adjustments			-	-	(8,581)	-	-	-	-	-	-	-	-	-	-	(8,581)
88	Working Capital Billed	Account 1163-1422 2/	-														-
90	Monthly (Over)/Under Recovery		$ 4,305	$ 4,620	$ 4,960	$ (3,270)	$ (2,932)	$ (2,608)	$ (2,283)	$ 9	$ 9,930	$ 20,114	$ 29,284	$ 32,123	$ 31,903	$ 31,986	$ 31,673
92	Average Monthly Balance	(ln 76 + ln 90)/2		$ 4,463	$ 4,798	$ 853	$ (3,099)	$ (2,776)	$ (2,451)	$ (1,141)	$ 4,967	$ 15,030	$ 24,721	$ 30,737	$ 32,059	$ 31,991	
94	Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
96	Interest Applied	ln 92 * ln 94 / 365 * Days of Month		$ 15	$ 16	$ 3	$ (11)	$ (10)	$ (9)	$ (4)	$ 18	$ 45	$ 66	$ 91	$ 92	$ -	$ 313
98	**(Over)/Under Balance**	ln 90 + ln 96	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,986	31,986

065

0513

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

101 **Calculation of Working Capital with Interest**

Schedule 3
Page 2 of 2

102

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

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

Adjustments		**Prior Period Adjustments**	**Refunds from Suppliers**	**Broker Revenue**	**Inventory Finance Charges**	**Transportation CGA Revenues (Schedule 17)**	**Interruptible Sales Margin**	**Off System Sales Margin**	**Capacity Release**	**Net Option Premiums**	**Fixed Price Option Administrative Costs**	**Total Adjustments**
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
May-18		$ -	$ -	-	$ -	$ -	$ -	[redacted]		$ -	$ -	$ -
Jun-18		-	-	-	-	-	-			-	-	-
Jul-18	1/	-	-	-	-	-	-			-	-	-
Aug-18	1/	-	-	-	-	-	-			-	-	-
Sep-18	1/	-	-	-	-	-	-			-	-	-
Oct-18	1/	-	-	-	-	-	-			-	-	-
Nov-18	1/	-	-	(227,504)	-	(3,273)	-			-	45,000	(515,120)
Dec-18	1/	-	-	(368,407)	-	(4,111)	-			-	-	(706,884)
Jan-19	1/	-	-	(17,997)	-	(5,091)	-			-	-	(307,129)
Feb-19	1/	-	-	703,749	-	(5,254)	-			-	-	383,528
Mar-19	1/	-	-	(369,992)	-	(4,696)	-			-	-	(682,508)
Apr-19	1/	-	-	(217,609)	-	(3,956)	-			-	-	(528,763)
Subtotal May 18 - Oct 18		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Nov 18 - Apr 19		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
Total Peak Period		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)

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

Ln											
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										**REDACTED**
2	**d/b/a Liberty Utilities**										**Schedule 5A**
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										**Page 1 of 1**
4	**Demand Costs**										
5											
6				Deferred							Peak
7				to Peak							Nov-Apr
8		Peak	Reference	May 18 -Oct 18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	[redacted]							
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 26 x days								
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 28 x days								
25	Portland Natural Gas		Sch 5B, ln 21 * Sch 5C ln 29 x days								
26	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 22 * Sch 5C ln 30 x days								
27	TransCanada via Union to Portland		Sch 5B, ln 23 * Sch 5C ln 31 x days								
28	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 24 * Sch 5C ln 32 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 25 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 36 x days								
31	National Fuel FST 2358	peak	Sch 5B, ln 27 * Sch 5C ln 38 x days								
32											
33	Subtotal Pipeline Demand Charges			$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 9,738,885
34											
35	**Peaking Supply**										
36	Tenn Gas Pipeline (Concord Latera) Z6-Z6	peak	Sch 5B, ln 30 * Sch 5C ln 26 x days	[redacted]							
37	ENGIE Demand FLS	peak	Per Contract								
38	ENGIE Demand	peak	Per Contract								
39	Subtotal Peaking Demand Charges			$ -	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ -	$ 4,968,750
40											
41	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 33 + ln 39	$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570	$ 14,707,635
42											
43	Less Transportation Capacity Credit			$ (524,979)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (406,202)	$ (4,399,152)
44											
45	**Total Supply, Pipeline & Peaking Demand**			$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368	$ 10,308,483
46											
47											
48	Dominion - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 61 x days	$ 10,464	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 20,928
49	Dominion - Storage	peak	Sch 5B, ln 36 * Sch 5C ln 62 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
50	Honeoye - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 65 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
51	National Fuel - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 67 x days	90,980	15,163	15,163	15,163	15,163	15,163	15,163	181,959
52	National Fuel - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 68 x days	153,345	25,557	25,557	25,557	25,557	25,557	25,557	306,690
53	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 41 * Sch 5C ln 71 x days	195,783	32,631	32,631	32,631	32,631	32,631	32,631	391,567
54	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 42 * Sch 5C ln 72 x days	191,928	31,988	31,988	31,988	31,988	31,988	31,988	383,856
55											
56	**Subtotal Storage Demand Costs**			$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 1,407,802
57											
58	Less Transportation Capacity Credit			$ (281,772)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (485,340)
59											
60	**Total Storage Demand Costs**		ln 56 + ln 58	$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 922,462
61											
62	**Total Demand Charges**		ln 41 + ln 56	$ 2,015,366	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 1,521,887	$ 16,115,438
63											
64	Total Transportation Capacity Credit		ln 43 + ln 58	$ (806,751)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (440,130)	$ (4,884,492)
65											
66	**Total Demand Charges less Cap. Cr.**		ln 62 + ln 64	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757	$ 11,230,946
67											
68							**REDACTED**				

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

		Peak	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply									
	Niagara Supply			3,199	3,199	3,199	3,199	3,199	3,199
Pipeline									
	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline		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		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Tenn Gas Pipeline (Concord Lateral)		Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
	Portland Natural Gas Trans Service		FTN-ENN0005	1,000	1,000	1,000	1,000	1,000	1,000
	Portland Natural Gas		FTN	1,784	1,784	1,784	1,784	1,784	1,784
	ANE (TransCanada via Union to Iroquois)		Union Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	TransCanada via Union to Portland		Union Parkway to Portland	1,784	1,784	1,784	1,784	1,784	1,784
	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
Peaking									
	Tenn Gas Pipeline (Concord Lateral)	peak		0	0	0	0	0	0
	ENGIE Demand FLS	peak		3,000	3,000	3,000	3,000	3,000	0
	ENGIE Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	0
Storage									
	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
	Honeoye - Capacity	peak	SS-NY	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

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

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

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

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

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

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

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

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

2018 CURRENT:

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

2017 TRUE-UP:

Debit/Credit Cost ($316,993) divided by 47,717,356,257 Dth	=	(0.0000066431)
TOTAL UNIT CHARGE	=	0.0013295571

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

PUBLIC

Dominion Energy Transmission, Inc.
FERC Gas Tariff
Fifth Revised Volume No. 1

GSS, GSS-E & ISS Rates - Settled Parties
Tariff Record No. 10.30.
Version 2.0.0
Superseding Version 1.0.0

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

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

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

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

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

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

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

(Footnotes continued on Sheet 4.01)

074

0522

1/ Transporter's Settlement dated August 18, 2016, in Docket No. RP16-301-000, which was approved by Commission order issued October 20, 2016, established new base tariff recourse rates referred to as "Settlement Rates" and a moratorium on changes to the Settlement Rates until September 1, 2020. All recourse Maximum and Minimum Rates listed on Sheet Nos. 4, 4B, 4C, and 5A are Settlement Rates subject to the moratorium.
2/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:
Commodity 1/

MEASUREMENT VARIANCE/FUEL USE FACTOR:

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

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

RATES FOR PART 284 STORAGE SERVICES

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

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 0.89%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ Rate per nomination.
7/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.1033 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.
8/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0015 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

Effective On: April 1, 2018

RATES FOR TRANSPORTATION SERVICES

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

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

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

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

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

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

Statement of Transportation Rates
(Rates per DTH)

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

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

____

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

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

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

Eleventh Revised Sheet No. 14
Superseding
Tenth 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	$5.5411		$11.5794	$15.5758	$15.8514	$17.4175	$18.4879	$23.1959
L		$4.9193						
1	$8.3417		$7.9962	$10.6413	$15.0745	$14.8460	$16.7429	$20.5878
2	$15.5759		$10.5774	$5.5014	$5.1427	$6.5803	$9.0504	$11.6830
3	$15.8514		$8.3784	$5.5458	$4.0009	$6.1457	$11.1149	$12.8437
4	$20.1259		$18.5544	$7.0708	$10.7456	$5.2598	$5.6884	$8.1265
5	$23.9973		$16.8625	$7.4172	$8.9748	$5.8432	$5.4810	$7.1353
6	$27.7603		$19.3678	$13.3296	$14.6845	$10.3726	$5.4568	$4.7237

Daily Base Reservation Rate 1/

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

Maximum Reservation Rates 2 /, 3 /

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

Notes:

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

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

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

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum Commodity Rates 1/, 2/

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

Maximum Commodity Rates 1/, 2/, 3/

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

Notes:

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

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

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

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

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

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

Fourteenth Revised Sheet No. 61
Superseding
Thirteenth Revised Sheet No. 61

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

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

Notes:

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

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

Thirteenth Revised Sheet No. 32
Superseding
Twelfth Revised Sheet No. 32

FUEL AND EPCR

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

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

EPCR 3/, 4/

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

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

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

Storage Transportation Service

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

Firm Transportation - Short Notice

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

Dawn Long Term Fixed Price

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

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

Enhanced Market Balancing Service

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

Delivery Pressure

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

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

Union Dawn Receipt Point Surcharge

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

Short Notice Balancing (SNB) Service

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

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

Energy Deficient Gas Allowance (EDGA) Service

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

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

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

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

REDACTED

Line	For Month of: (a)	Reference (b)	Nov-18 (c)	Dec-18 (d)	Jan-19 (e)	Feb-19 (f)	Mar-19 (g)	Apr-19 (h)	Peak Nov- Apr (i)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas**								
12	Dawn Supply	ln 64 * ln 104	[redacted]						
13	Niagara Supply	ln 65 * ln 109							
14	TGP Supply (Direct)	ln 66 * ln 125							
15	Dracut Supply 1 - Baseload	ln 67 * ln 114							
16	Dracut Supply 2 - Swing	ln 68 * ln 119							
17	ENG E COMBO	ln 69 * ln 131							
18	LNG Truck	ln 70 * ln 133							
19	Propane Truck	ln 71 * ln 135							
20	PNGTS	ln 72 * ln 140							
21	Portland Natural Gas	ln 73 * ln 145							
22	TGP Supply (Z4)	ln 74 * ln 150							
23									
24	Subtotal Pipeline Gas Costs		$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499	$ 42,563,780
25									
26	**Volumetric Transportation Costs**								
27	Dawn Supply	ln 64 * ln 197	[redacted]						
28	Niagara Supply	ln 65 * ln 208							
29	TGP Supply (Direct)	ln 66 * ln 235							
30	Dracut Supply 1 - Baseload	ln 67 * ln 256							
31	Dracut Supply 2 - Swing	ln 68 * ln 256							
32	ENG E COMBO	ln 69 * ln 256							
33	TGP Storage - Withdrawals	ln 79 * ln 172							
34									
35	**Total Volumetric Transportation Costs**		$ 215,648	$ 213,629	$ 237,663	$ 219,674	$ 201,319	$ 38,974	$ 1,126,907
36									
37	**Less - Gas Refill**								
38	LNG Truck	ln 88 * ln 157	[redacted]						
39	Propane	ln 89 * ln 158							
40	TGP Storage Refill	ln 90 * ln 123							
41	Storage Refill (Trans.)	ln 90 * ln 235							
42									
43	Subtotal Refills		$ (765,580)	$ (131,625)	$ (809,867)	$ (600,010)	$ (65,260)	$ -	$ (2,372,341)
44									
45	**Total Supply & Pipeline Commodity Costs**	ln 24 + ln 35 + ln 43	$ 2,553,342	$ 8,898,538	$ 11,299,833	$ 10,827,598	$ 5,600,561	$ 2,138,473	$ 41,318,346
46									
47	**Storage Gas**								
48	TGP Storage - Withdrawals	ln 79 * ln 164	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894	$ 5,125,663
49									
50	**Produced Gas**								
51	LNG Vapor	ln 82 * ln 152	[redacted]						
52	Propane	ln 83 * ln 154							
53									
54	**Total Produced Gas**	ln 51 + ln 52	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567	$ 2,672,211
55									
56									
57	**Total Commodity Gas & Trans. Costs**	ln 45 + ln 48 + ln 54	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935	$ 49,116,221
58									$ 87,958,623
59						**REDACTED**			

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

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089

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

090
0538

REDACTED

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

REDACTED

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REDACTED

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
211									
212									
213	**TGP Direct Volumetric Transportation Charge**								Average Rate
214	**Commodity Costs**	Ln 123	[redacted]						
215									
216	TGP - Max Comm. Base Rate - Z 0-6	13th Rev Sheet No. 15	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039
217	TGP - Max Commodity ACA Rate - Z 0-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
218	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052
219	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
220	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**
221	TGP - Max Comm. Base Rate - Z 1-6	13th Rev Sheet No. 15	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650
222	TGP - Max Commodity ACA Rate - Z 1-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
223	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663
224	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**
226	TGP - Fuel Charge % - Z 0 -6	13th Rev Sheet No. 32	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%
227	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
228	Prorated TGP Fuel Charge % - Z 0-6		1.45%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%
229	TGP - Fuel Charge % - Z 1 -6	13th Rev Sheet No. 32	3.88%	3.88%	3.88%	3 88%	3.88%	3.88%	3.88%
230	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
231	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
232	TGP - Fuel Charge % - Z 0-6	ln 215 x ln 229	**$0.00427**	**$0.00440**	**$0.00453**	**$0.00447**	**$0.00432**	**$0.00387**	**$0.00431**
233	TGP - Fuel Charge % - Z 1-6	ln 215 x ln 232	**$0.00771**	**$0.00796**	**$0.00818**	**$0.00808**	**$0.00781**	**$0.00699**	**$0.00779**
234	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03987**	**$0.04026**	**$0.04060**	**$0.04045**	**$0.04003**	**$0.03876**	**$0.04000**
235									
236	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
237	**Commodity Costs**	Ln 123	[redacted]						
238									
239	TGP - Max Comm. Base Rate - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
240	TGP - Max Commodity ACA Rate - Z 6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
241	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
242	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
243	TGP - Fuel Charge	ln 238 x ln 243	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**
244	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**
245									
246									
247	**TGP Dracut**								
248	**Commodity Costs - NYMEX Price**	Ln 114	[redacted]						
249									
250	TGP - Trans Charge - Comm. - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
251	TGP - Trans Charge - ACA Rate - Z6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
252	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
253	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
254	TGP - Fuel Charge	ln 249 x ln 254	[redacted]						
255	**Total Volumetric Transportation Rate - TGP Dracut**								
256									
257									

REDACTED

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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**									
2	**d/b/a Liberty Utilities**									
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**									
4	**NYMEX Futures @ Henry Hub**									
5										Peak
6	For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of**									
9	Opening Prices (15 day average)			2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$ 2.9782
10	NYMEX		**Filed COG**	2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$ 2.9782

0541

093

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub**
5

5										Peak
6	For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NYMEX Settlement - 15 Day Average									
8		Days	Date							
9		1	21-Aug	2 9910	3.0830	3.1670	3.1310	3.0270	2.7090	
10		2	20-Aug	2 9660	3.0610	3.1450	3.1090	3.0060	2.7010	
11		3	17-Aug	2 9860	3.0820	3.1680	3.1320	3.0280	2.7080	
12		4	16-Aug	2 9500	3.0460	3.1340	3.1000	2.9980	2.6930	
13		5	15-Aug	2 9850	3.0780	3.1650	3.1280	3.0220	2.7060	
14										
15										
16		6	14-Aug	3.0020	3.0920	3.1760	3.1380	3.0320	2.7130	
17		7	13-Aug	2 9710	3.0590	3.1450	3.1090	3.0040	2.6980	
18		8	10-Aug	2 9820	3.0670	3.1510	3.1130	3.0080	2.6910	
19		9	9-Aug	2 9920	3.0770	3.1620	3.1250	3.0220	2.6980	
20		10	8-Aug	2 9890	3.0770	3.1630	3.1240	3.0190	2.6910	
21										
22										
23		11	7-Aug	2 9350	3.0310	3.1170	3.0800	2.9740	2.6570	
24		12	6-Aug	2 9030	3.0030	3.0900	3.0520	2.9470	2.6340	
25		13	3-Aug	2 8980	2.9980	3.0820	3.0450	2.9410	2.6260	
26		14	2-Aug	2 8570	2.9580	3.0430	3.0060	2.9030	2.6050	
27		15	1-Aug	2 8110	2.9190	3.0050	2.9710	2.8680	2 5820	
28										
29										
30										
31										
32										
33										
34										
35			15 Day Average	2 9479	3.0421	3.1275	3.0909	2.9866	2.6741	

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

November 1, 2018 - April 30, 2019 / **May 1, 2018 - October 31, 2018**
Residential Heating (R3)

PROPOSED			Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
	5/1/2018	7/1/2018															
Winter:																	
Cust. Chg	$24.43	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12								
Headblock	$0.3863	$0.5631	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.3197	$0.5631	$21.33	$53.70	$88.19	$78.12	$60.12	$56.40	$357.86								
HB Threshold	100	-															
Summer:																	
Cust. Chg	$14.88	$15.02								$14.88	$14.88	$15.02	$15.02	$15.02	$15.02	$89.84	$179.96
Headblock	$0.5580	$0.5631								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.5580	$0.5631								$30.99	$11.84	$9.43	$8.47	$8.80	$10.15	$79.67	$437.53
HB Threshold	-	-															
Total Base Rate Amount			$36.35	$68.72	$103.21	$93.14	$75.14	$71.42	$447.98	$45.87	$26.72	$24.45	$23.49	$23.82	$25.17	$169.51	$617.49
COG Rate - (Seasonal)			$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.3133	$0.3916	$0.3127	$0.3665	$0.3916	$0.3916	$0.3491	$0.6694
COG amount			$28.07	$70.68	$116.07	$102.82	$79.12	$74.23	$470.98	$17.40	$8.31	$5.24	$5.51	$6.12	$7.06	$49.63	$520.62
LDAC			$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0856
LDAC amount			$3.17	$7.98	$13.10	$11.60	$8.93	$8.38	$53.15	$5.25	$2.00	$1.58	$1.42	$1.48	$1.70	$13.44	$66.59
Total Bill			**$67.58**	**$147.37**	**$232.37**	**$207.57**	**$163.19**	**$154.03**	**$972.12**	**$68.51**	**$37.03**	**$31.27**	**$30.42**	**$31.42**	**$33.93**	**$232.58**	**$1,204.70**

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Residential Heating (R3)

CURRENT			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
Winter:	5/1/2017	7/1/2017															
Cust. Chg	$22.10	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58								
Headblock	$0.3495	$0.3863	$14.63	$36.84	$38.63	$38.63	$38.63	$38.63	$205.99								
Tailblock	$0.2892	$0.3197	$0.00	$0.00	$18.10	$12.39	$2.16	$0.05	$32.70								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$22.10	$24.43								$22.10	$22.10	$24.43	$24.43	$24.43	$24.43	$141.92	$288.50
Headblock	$0.3495	$0.3863								$6.99	$6.99	$6.47	$5.81	$6.04	$6.96	$39.26	$245.25
Tailblock	$0.2892	$0.3197								$10.27	$0.35	$0.00	$0.00	$0.00	$0.00	$10.63	$43.32
HB Threshold	20	20															
Total Base Rate Amount			$39.06	$61.27	$81.16	$75.45	$65.22	$63.11	$385.27	$39.36	$29.44	$30.90	$30.24	$30.47	$31.39	$191.81	$577.08
COG Rate - (Seasonal)			$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7321	$0.4368	$0.4368	$0.4368	$0.4725	$0.4725	$0.4725	$0.4490	$0.6804
COG amount			$24.41	$61.46	$100.94	$111.77	$86.01	$80.69	$465.28	$24.26	$9.27	$7.31	$7.11	$7.39	$8.52	$63.84	$529.12
LDAC			$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0817
LDAC amount			$3.24	$8.16	$13.41	$11.88	$9.14	$8.57	$54.40	$3.55	$1.36	$1.07	$0.96	$1.00	$1.15	$9.10	$63.50
Total Bill			**$66.71**	**$130.90**	**$195.50**	**$199.09**	**$160.37**	**$152.38**	**$904.95**	**$67.17**	**$40.07**	**$39.28**	**$38.31**	**$38.85**	**$41.07**	**$264.75**	**$1,169.70**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$0.87**	**$16.48**	**$36.87**	**$8.48**	**$2.82**	**$1.65**	**$67.17**	**$1.34**	**($3.04)**	**($8.02)**	**($7.89)**	**($7.43)**	**($7.13)**	**($32.17)**	**$35.00**
% Change	**1.30%**	**12.59%**	**18.86%**	**4.26%**	**1.76%**	**1.08%**	**7.42%**	**1.99%**	**-7.58%**	**-20.41%**	**-20.59%**	**-19.13%**	**-17.37%**	**-12.15%**	**2.99%**
Base Rate	($2.71)	$7.45	$22.05	$17.70	$9.92	$8.31	$62.71	$6.50	($2.72)	($6.45)	($6.75)	($6.65)	($6.22)	($22.29)	$40.42
% Change	-6.95%	12.16%	27.17%	23.46%	15.20%	13.17%	16.28%	16.51%	-9.25%	-20.87%	-22.33%	-21.81%	-19.82%	-11.62%	7.00%
COG & LDAC	$3.58	$9.03	$14.82	($9.22)	($7.10)	($6.66)	$4.46	($5.16)	($0.31)	($1.57)	($1.14)	($0.79)	($0.91)	($9.88)	($5.42)
% Change	14.68%	14.68%	14.68%	-8.25%	-8.25%	-8.25%	0.96%	-21.29%	-3.37%	-21.43%	-15.98%	-10.67%	-10.67%	-15.47%	-1.02%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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

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

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

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

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

DIFFERENCE:

Total Bill			**$9.42**	**$38.32**	**$66.43**	**($12.85)**	**($8.22)**	**($6.97)**	**$86.13**	**$10.41**	**$6.77**	**$1.22**	**$4.62**	**$3.37**	**($1.30)**	**$25.09**	**$111.22**
% Change			**5.86%**	**11.06%**	**11.57%**	**-2.14%**	**-1.81%**	**-1.68%**	**3.38%**	**6.73%**	**8.24%**	**1.60%**	**5.77%**	**4.46%**	**-1.56%**	**4.54%**	**3.59%**
Base Rate			($0.05)	$8.74	$12.64	$11.82	$9.66	$9.08	$51.88	$22.76	$6.92	$3.40	$6.79	$4.36	($0.15)	$44.08	$95.97
% Change			-0.05%	5.85%	5.85%	5.85%	5.85%	5.85%	5.26%	27.27%	10.79%	5.27%	10.73%	6.91%	-0.21%	10.82%	6.89%
COG & LDAC			$9.47	$29.59	$53.79	($24.68)	($17.88)	($16.04)	$34.25	($12.36)	($0.15)	($2.17)	($2.17)	($0.99)	($1.15)	($18.99)	$15.26
% Change			16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.39%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-14.42%	0.98%
check			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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

Line										Winter							Summer	Total
9	**PROPOSED**																	
10				**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**May-Oct**	**Nov-Oct**
11	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
12		7/1/2018	5/1/2018															
13	**Winter:**																	
14	Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50								
15	Headblock	$0.4219	$0.3986	$350.20	$421.90	$421.90	$421.90	$421.90	$421.90	$2,459.70								
16	Tailblock	$0.2811	$0.2655	$0.00	$334.13	$761.08	$676.27	$450.55	$392.11	$2,614.13								
17	HB Threshold	1,000	1,000															
18																		
19	**Summer:**																	
20	Cust. Chg	$169.75	$168.21								$160.36	$160.36	$169.75	$169.75	$169.75	$169.75	$999.72	$2,018.22
21	Headblock	$0.4219	$0.4181								$167.24	$167.24	$120.07	$104.03	$113.31	$143.61	$815.50	$3,275.21
22	Tailblock	$0.2811	$0.2785								$255.94	$23.42	$0.00	$0.00	$0.00	$0.00	$279.36	$2,893.49
23	HB Threshold	400	400															
24																		
25	Total Base Rate Amount			$519.95	$925.78	$1,352.73	$1,267.92	$1,042.20	$983.76	$6,092.33	$583.54	$351.02	$289.82	$273.78	$283.06	$313.36	$2,094.59	$8,186.92
26																		
27	COG Rate - (Seasonal)			$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.3084	$0.3855	$0.3066	$0.3604	$0.3855	$0.3855	$0.3412	$0.6753
28	COG amount			$614.49	$1,620.25	$2,744.67	$2,521.30	$1,926.86	$1,772.94	$11,200.51	$406.78	$186.62	$87.26	$88.87	$103.54	$131.22	$1,004.28	$12,204.79
29																		
30	LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0770
31	LDAC amount			$64.04	$168.87	$286.06	$262.78	$200.82	$184.78	$1,167.36	$100.64	$36.94	$21.71	$18.81	$20.49	$25.97	$224.57	$1,391.93
32																		
33	**Total Bill**			**$1,198.49**	**$2,714.89**	**$4,383.46**	**$4,052.00**	**$3,169.88**	**$2,941.48**	**$18,460.21**	**$1,090.97**	**$574.57**	**$398.79**	**$381.46**	**$407.09**	**$470.55**	**$3,323.43**	**$21,783.64**
34																		

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

Line										Winter							Summer	Total
37	**CURRENT**																	
38				**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**May-Oct**	**Nov-Oct**
39	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
40		5/1/2017	7/1/2017															
41	**Winter:**																	
42	Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
43	Headblock	$0.3606	$0.3986	$330.86	$398.60	$398.60	$398.60	$398.60	$398.60	$2,323.86								
44	Tailblock	$0.2402	$0.2655	$0.00	$315.58	$718.84	$638.74	$425.54	$370.34	$2,469.05								
45	HB Threshold	1,000	1,000															
46																		
47	**Summer:**																	
48	Cust. Chg	$145.08	$160.36								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
49	Headblock	$0.3606	$0.3986								$144.24	$144.24	$113.44	$98.29	$107.06	$135.68	$742.94	$3,066.80
50	Tailblock	$0.2402	$0.2655								$220.75	$28.09	$0.00	$0.00	$0.00	$0.00	$248.84	$2,717.89
51	HB Threshold	400	400															
52																		
53	Total Base Rate Amount			$491.22	$874.54	$1,277.80	$1,197.70	$984.50	$929.30	$5,755.08	$510.07	$317.41	$273.80	$258.65	$267.42	$296.04	$1,923.37	$7,678.45
54																		
55	COG Rate - (Seasonal)			$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7326	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4310	$0.6835
56	COG amount			$533.98	$1,407.95	$2,385.04	$2,738.59	$2,092.92	$1,925.74	$11,084.22	$554.78	$203.61	$119.70	$112.51	$122.55	$155.32	$1,268.47	$12,352.68
57																		
58	LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0638
59	LDAC amount			$55.95	$147.51	$249.89	$229.55	$175.43	$161.42	$1,019.74	$59.36	$21.78	$12.81	$11.10	$12.09	$15.32	$132.45	$1,152.19
60																		
61	**Total Bill**			**$1,081.15**	**$2,430.01**	**$3,912.73**	**$4,165.84**	**$3,252.85**	**$3,016.46**	**$17,859.03**	**$1,124.20**	**$542.80**	**$406.30**	**$382.26**	**$402.05**	**$466.67**	**$3,324.29**	**$21,183.32**
62																		
63	**DIFFERENCE:**																	
64	**Total Bill**			**$117.35**	**$284.88**	**$470.73**	**($113.84)**	**($82.97)**	**($74.98)**	**$601.17**	**($33.23)**	**$31.77**	**($7.51)**	**($0.79)**	**$5.04**	**$3.88**	**($0.85)**	**$600.32**
65	% Change			**10.85%**	**11.72%**	**12.03%**	**-2.73%**	**-2.55%**	**-2.49%**	**3.37%**	**-2.96%**	**5.85%**	**-1.85%**	**-0.21%**	**1.25%**	**0.83%**	**-0.03%**	**2.83%**
66																		
67	**Base Rate**			$28.73	$51.23	$74.93	$70.22	$57.69	$54.45	$337.25	$73.48	$33.61	$16.02	$15.14	$15.65	$17.32	$171.21	$508.47
68	% Change			5.85%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	14.41%	10.59%	5.85%	5.85%	5.85%	5.85%	8.90%	6.62%
69																		
70	**COG & LDAC**			$88.61	$233.65	$395.80	($184.06)	($140.66)	($129.43)	$263.92	($106.71)	($1.84)	($23.54)	($15.93)	($10.61)	($13.45)	($172.07)	$91.85
71	% Change			16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.38%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-13.56%	0.74%
	check			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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

November 1, 2018 - April 30, 2019
Commercial Rate (G-52)

PROPOSED			Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr
average Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,306
Winter:	7/1/2018	5/1/2018							
Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50
Headblock	$0.2401	$0.2268	$240.10	$240.10	$240.10	$240.10	$240.10	$240.10	$1,440.60
Tailblock	$0.1600	$0.1511	$56.28	$138.55	$205.37	$185.54	$141.69	$121.61	$849.04
HB Threshold	1,000	1,000							
Summer:									
Cust. Chg	$169.75	$168.21							
Headblock	$0.1740	$0.1724							
Tailblock	$0.0989	$0.0980							
HB Threshold	1,000	1,000							
Total Base Rate Amount			$466.13	$548.40	$615.22	$595.39	$551.54	$531.46	$3,308.14
COG Rate - (Seasonal)			$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456
COG amount			$1,007.86	$1,391.23	$1,702.65	$1,610.22	$1,405.86	$1,312.30	$8,430.11
LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772
LDAC amount			$104.30	$143.97	$176.19	$166.63	$145.48	$135.80	$872.37
Total Bill			**$1,578.29**	**$2,083.59**	**$2,494.07**	**$2,372.23**	**$2,102.88**	**$1,979.56**	**$12,610.61**

May 1, 2018 - October 31, 2018

	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
average Usage (Therms)	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
Cust. Chg	$168.21	$168.21	$169.75	$169.75	$169.75	$169.75	$1,015.42	$2,033.92
Headblock	$172.40	$172.40	$174.00	$174.00	$174.00	$156.04	$1,022.84	$2,463.44
Tailblock	$49.15	$12.63	$3.16	$2.48	$4.92	$0.00	$72.35	$921.38
Total Base Rate Amount	$389.76	$353.24	$346.91	$346.23	$348.67	$325.79	$2,110.61	$5,418.74
COG Rate - (Seasonal)	$0.3299	$0.4124	$0.3335	$0.3873	$0.4124	$0.4124	$0.3776	$0.6096
COG amount	$493.86	$465.08	$344.16	$397.00	$432.94	$369.83	$2,502.87	$10,932.98
LDAC	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0768
LDAC amount	$114.22	$86.05	$78.74	$78.21	$80.10	$68.42	$505.74	$1,378.11
Total Bill	**$997.85**	**$904.37**	**$769.80**	**$821.44**	**$861.71**	**$764.05**	**$5,119.22**	**$17,729.83**

November 1, 2017 - April 30, 2018
Commercial Rate (G-52)

CURRENT			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr
average Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,306
Winter:	5/1/2017	7/1/2017							
Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16
Headblock	$0.2052	$0.2268	$226.80	$226.80	$226.80	$226.80	$226.80	$226.80	$1,360.80
Tailblock	$0.1367	$0.1511	$53.15	$130.84	$193.95	$175.22	$133.81	$114.84	$801.81
HB Threshold	1,000	1,000							
Summer:									
Cust. Chg	$145.08	$160.36							
Headblock	$0.1487	$0.1644							
Tailblock	$0.0845	$0.0934							
HB Threshold	1,000	1,000							
Total Base Rate Amount			$440.31	$518.00	$581.11	$562.38	$520.97	$502.00	$3,124.77
COG Rate - (Seasonal)			$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7397
COG amount			$886.74	$1,224.04	$1,498.04	$1,764.63	$1,546.14	$1,443.25	$8,362.84
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674
LDAC amount			$91.11	$125.76	$153.91	$145.56	$127.09	$118.63	$762.06
Total Bill			**$1,418.16**	**$1,867.80**	**$2,233.06**	**$2,472.57**	**$2,194.19**	**$2,063.88**	**$12,249.67**

May 1, 2017 - October 31, 2017

	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
average Usage (Therms)	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
Cust. Chg	$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
Headblock	$148.70	$148.70	$164.40	$164.40	$164.40	$147.43	$938.03	$2,298.83
Tailblock	$32.97	$7.82	$2.98	$2.34	$4.65	$0.00	$50.76	$852.57
Total Base Rate Amount	$326.75	$301.60	$327.74	$327.10	$329.41	$307.79	$1,920.40	$5,045.16
COG Rate - (Seasonal)	$0.4574	$0.4574	$0.4574	$0.4931	$0.4931	$0.4931	$0.4734	$0.6413
COG amount	$684.73	$515.83	$472.01	$505.45	$517.65	$442.21	$3,137.88	$11,500.72
LDAC	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0591
LDAC amount	$67.37	$50.75	$46.44	$46.13	$47.24	$40.36	$298.27	$1,060.33
Total Bill	**$1,078.85**	**$868.18**	**$846.20**	**$878.68**	**$894.31**	**$790.35**	**$5,356.55**	**$17,606.22**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
Total Bill	**$160.13**	**$215.79**	**$261.00**	**($100.33)**	**($91.32)**	**($84.32)**	**$360.95**
% Change	**11.29%**	**11.55%**	**11.69%**	**-4.06%**	**-4.16%**	**-4.09%**	**2.95%**
Base Rate	$25.82	$30.40	$34.11	$33.01	$30.57	$29.45	$183.37
% Change	5.86%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%
COG & LDAC	$134.31	$185.39	$226.89	($133.34)	($121.89)	($113.78)	$177.58
% Change	15.15%	15.15%	15.15%	-7.56%	-7.88%	-7.88%	2.12%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($81.00)**	**$36.19**	**($76.39)**	**($57.24)**	**($32.60)**	**($26.30)**	**($237.34)**	**$123.61**
% Change	**-7.51%**	**4.17%**	**-9.03%**	**-6.51%**	**-3.64%**	**-3.33%**	**-4.43%**	**0.70%**
Base Rate	$63.01	$51.64	$19.17	$19.13	$19.26	$18.00	$190.21	$373.58
% Change	19.28%	17.12%	5.85%	5.85%	5.85%	5.85%	9.90%	7.40%
COG & LDAC	($144.01)	($15.45)	($95.56)	($76.37)	($51.86)	($44.30)	($427.55)	($249.97)
% Change	-21.03%	-3.00%	-20.24%	-15.11%	-10.02%	-10.02%	-13.63%	-2.17%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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

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

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

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

Line	Description	Reference		Capacity Cost	MDQ, Dt	$/Dt-Mo.	Ratios for COG
51							
52							
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		1,050,276	6,608	$13 2459	
55	Pipeline - Remaining	Line 39 - Line 47		6,041,275	38,007	$13 2458	
56	Storage	Line 40 - Line 48		2,459,310	15,735	$13 0248	
57	Peaking	Line 41 - Line 49		2,780,941	31,754	$7 2981	
58	Total		**55.966%**	12,331,802	92,104	$11.1575	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		447,308	2,814	$13 2465	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		5,182,374	32,604	$13 2458	
64	Storage	Line 56 * Line 24 Col F		2,109,664	13,498	$13 0245	
65	Peaking	Line 57 * Line 24 Col F		2,385,568	27,239	$7 2983	
66	Total		**45.9503%**	10,124,914	76,155	$11 0793	**0.9930**
67			42.590%	82%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		602,968	3,794	$13 2439	
71	Pipeline - Remaining	Line 55 - Line 63		858,901	5,403	$13 2473	
72	Storage	Line 56 - Line 64		349,646	2,237	$13 0251	
73	Peaking	Line 57 - Line 65		395,373	4,515	$7 2974	
74	Total		**10.0156%**	2,206,888	15,949	$11 5310	**1.0335**
75							(Line 74 / Line 58)

Line	Description	Residential	LLF C&I	HLF C&I	Total
76					
77	Unit Cost	Residential	LLF C&I	HLF C&I	
78					
79	Pipeline	$ 13 2459	$ 13.2459	$ 13.2459	
80	Storage	$ 13 0247	$ 13.0247	$ 13.0247	
81	Peaking	$ -	$ -	$ -	
82	Total	$ 11.1575	$ 11.0793	$ 11.5310	
83					
84					
85	Load Makeup	Residential	**LLF C&I**	**HLF C&I**	
86					
87	Pipeline	48.44%	**46.51%**	**57.67%**	
88	Storage	17.08%	**17.72%**	**14.03%**	
89	Peaking	34.48%	**35.77%**	**28.31%**	
90	Total	100.00%	**100.00%**	**100.00%**	
91					
92					
93	Supply Makeup	Residential	LLF C&I	HLF C&I	Total
94					
95	Pipeline	44.03%	44.43%	11.54%	100.00%
96	Storage	44.03%	48.01%	7.96%	100.00%
97	Peaking	44.03%	48.01%	7.96%	100.00%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **2017-2018 Winter Calculation**
4 **Correction Factor Calculation**
5
6

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

24
25

Ln		Value	Source
26	Total Sales	33,607,703	
27	Low Winter Use	4,889,046	
28	Winter Ratio for Low Winter Use	**1.0335**	Schedule 10A p 2, ln 74
29	High Winter Use	28,718,657	
30	Winter Ratio for High Winter Use	**0.9930**	Schedule 10A p 2, ln 66

31
32 Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use
33 Correction Factor = **100.1110%**
34
35
36 **Allocation Calculation for Miscellaneous Overhead**
37

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

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

7	**Firm Sales**							**Subtotal**							**Subtotal**	
8		**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**PK 18-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**OP 19**	**Total**
9	R-1	58,148	73,323	85,127	87,489	80,107	60,928	445,123	44,082	30,039	23,238	24,503	31,923	43,218	197,003	642,126
10	R-3	4,041,030	7,405,866	10,502,345	11,246,925	9,528,683	6,407,575	49,132,423	3,690,099	1,773,275	1,006,300	981,527	1,481,613	2,659,147	11,591,962	60,724,385
11	R-4	225,090	424,725	668,812	822,921	728,538	573,586	3,443,671	361,052	178,352	90,516	79,349	97,393	150,109	956,771	4,400,443
12	Total Residential.	4 324 268	7 903 914	11 256 284	12 157 335	10 337 327	7 042 089	53 021 218	4 095 234	1 981 666	1 120 055	1 085 379	1 610 929	2 852 473	12 745 736	65 766 954
13																
14	G-41	1,321,101	2,319,276	3,165,299	3,498,870	2,926,465	1,918,416	15,149,429	800,746	362,796	221,001	168,493	181,679	460,013	2,194,729	17,344,157
15	G-42	895,704	1,551,977	2,083,542	2,176,169	1,812,337	1,285,485	9,805,213	748,675	460,256	231,012	116,114	74,965	227,916	1,858,939	11,664,152
16	G-43	360,692	504,475	733,059	836,182	731,266	598,340	3,764,015	304,113	197,948	134,668	105,947	121,390	192,087	1,056,153	4,820,168
17	G-51	135,964	177,998	217,956	227,659	210,007	162,636	1,132,220	115,160	74,244	56,098	56,385	71,155	94,990	468,032	1,600,252
18	G-52	146,420	183,177	224,756	238,484	224,688	178,727	1,196,252	131,291	88,424	68,817	68,840	84,354	107,862	549,588	1,745,840
19	G-53	156,779	249,279	616,066	508,733	461,553	413,241	2,405,652	291,255	205,865	165,249	156,854	172,243	202,036	1,193,502	3,599,154
20	G-54	23,619	24,600	26,018	27,451	27,760	25,474	154,923	23,468	19,194	16,830	17,609	20,668	21,777	119,546	274,468
21	Total C/I	3 040 279	5 010 783	7 066 697	7 513 549	6 394 077	4 582 318	33 607 703	2 414 708	1 408 727	893 675	690 242	726 454	1 306 681	7 440 489	41 048 192
22																
23	**Sales Volume**	**7,364,547**	**12,914,697**	**18,322,981**	**19,670,884**	**16,731,404**	**11,624,407**	**86,628,921**	**6,509,942**	**3,390,393**	**2,013,730**	**1,775,621**	**2,337,384**	**4,159,155**	**20,186,225**	**106,815,146**
24																
25	Transportation Sales															
26																
27	G-41	575,879	819,379	1,110,280	1,198,083	994,081	780,156	5,477,859	419,152	223,968	126,739	130,012	177,081	307,285	1,384,236	6,862,094
28	G-42	1,709,642	2,476,139	3,396,451	3,680,772	3,051,299	2,391,810	16,706,114	1,277,699	653,670	331,128	308,102	424,112	829,661	3,824,373	20,530,487
29	G-43	916,199	1,344,906	1,729,807	1,910,992	1,765,170	1,398,691	9,065,765	1,166,024	718,428	474,845	407,575	463,279	699,961	3,930,112	12,995,877
30	G-51	42,394	46,822	55,046	63,877	60,806	58,506	327,451	77,824	67,235	64,233	77,040	88,667	80,334	455,334	782,784
31	G-52	222,033	234,604	257,794	277,352	269,034	248,554	1,509,370	283,695	260,424	264,769	323,847	380,983	356,910	1,870,628	3,379,999
32	G-53	465,205	609,368	785,673	886,023	881,490	807,226	4,434,985	739,996	529,662	363,450	297,063	282,627	351,494	2,564,292	6,999,276
33	G-54	2,364,482	2,375,492	2,456,766	2,089,499	2,011,618	1,925,018	13,222,874	1,781,763	1,808,656	1,788,616	1,955,455	2,061,440	2,219,044	11,614,976	24,837,850
34																
35	Total Trans. Sales	**6,295,834**	**7,906,710**	**9,791,817**	**10,106,599**	**9,033,498**	**7,609,960**	**50,744,418**	**5,746,154**	**4,262,044**	**3,413,780**	**3,499,094**	**3,878,188**	**4,844,690**	**25,643,949**	**76,388,368**
36																
37	Total All Sales	**13,660,381**	**20,821,407**	**28,114,798**	**29,777,484**	**25,764,902**	**19,234,367**	**137,373,339**	**12,256,096**	**7,652,437**	**5,427,510**	**5,274,715**	**6,215,572**	**9,003,844**	**45,830,174**	**183,203,513**

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Normal and Design Year Volumes** — **Schedule 11A**
5 **Page 1 of 1**

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

9 **For the Months of November 18 - April 19**

Line		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
13	Pipeline Gas:							
14	Dawn Supply	796,342	878,932	897,468	806,735	883,624	543,941	4,807,042
15	Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
16	TGP Supply (Gulf)	4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382	16,183,681
17	Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
18	Dracut Supply 2 - Swing	2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232	11,732,071
19	ENGIE Combo	-	945,993	1,229,648	1,264,827	734,441	-	4,174,908
20	LNG Truck	18,690	289,648	685,485	1,029,982	145,597	-	2,169,402
21	Propane Truck	-	-	356,219	91,328	-	-	447,548
22	PNGTS	198,251	197,617	108,541	146,415	191,500	201,686	1,044,010
23	Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	260,087	2,111,074
24	TGP Supply (Z4)	1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079	12,999,054
25	Subtotal Pipeline Volumes	10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703	69,847,042
26								
27	Storage Gas:							
28	TGP Storage	1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558	19,841,326
29								
30	Produced Gas:							
31	LNG Vapor	18,690	289,648	777,271	1,029,982	64,550	19,014	2,199,156
32	Propane	-	-	859,588	91,328	-	-	950,916
33	Subtotal Produced Gas	18,690	289,648	1,636,859	1,121,310	64,550	19,014	3,150,073
34								
35	Less - Gas Refills:							
36	LNG Truck	(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-	(2,169,402)
37	Propane	-	-	(356,219)	(91,328)	-	-	(447,548)
38	TGP Storage Refill	(2,262,867)	-	-	-	-	-	(2,262,867)
39	Subtotal Refills	(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-	(4,879,817)
40								
41	Total Sendout Volumes	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276	87,958,623
42								

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
43 **Normal and Design Year Volumes** — **Schedule 11B**
44 **Page 1 of 1**

Line	Volumes (Therms)	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
45								
46	**Volumes (Therms)**	**Design Year**						
47								
48	**For the Months of November 18 - April 19**							
49								
52	Pipeline Gas:							
53	Dawn Supply	796,342	878,932	897,468	806,735	883,624	617,960	4,881,061
54	Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
55	TGP Supply (Gulf)	4,154,598	2,956,407	3,018,756	2,713,035	2,876,080	584,686	16,303,562
56	Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
57	Dracut Supply 2 - Swing	3,107,938	3,496,465	3,388,088	3,348,710	4,354,285	2,136,377	19,831,864
58	ENGIE Combo	-	1,277,020	1,048,260	1,113,337	730,137	-	4,168,754
59	LNG Truck	19,358	54,220	759,788	885,016	452,570	-	2,170,952
60	Propane Truck	-	-	303,770	144,966	-	-	448,735
61	PNGTS	198,251	219,020	115,097	158,013	205,844	201,686	1,097,911
62	Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	311,697	2,162,684
63	TGP Supply (Z4)	1,641,413	1,819,931	1,858,313	1,670,006	1,829,646	4,234,727	13,054,036
64	Subtotal Pipeline Volumes	10,889,131	14,422,474	16,991,430	14,861,168	12,410,180	8,723,428	78,297,812
65								
66	Storage Gas:							
67	TGP Storage	1,371,738	4,289,074	5,080,310	4,651,952	3,946,183	155,509	19,494,766
68								0
69	Produced Gas:							0
70	LNG Vapor	18,690	54,933	851,575	885,016	371,524	19,014	2,200,752
71	Propane	-	-	807,138	144,966	-	-	952,104
72	Subtotal Produced Gas	18,690	54,933	1,658,713	1,029,982	371,524	19,014	3,152,857
73								
74	Less - Gas Refills:							
75	LNG Truck	(19,358)	(54,220)	(759,788)	(885,016)	(452,570)	-	-2,170,952
76	Propane	-	-	(303,770)	(144,966)	-	-	-448,735
77	TGP Storage Refill	(1,843,002)	-	-	-	-	-	-1,843,002
78	Subtotal Refills	(1,862,360)	(54,220)	(1,063,558)	(1,029,982)	(452,570)	-	(4,462,690)
79								
80	Total Sendout Volumes	10,417,200	18,712,261	22,666,896	19,513,121	16,275,316	8,897,951	96,482,745

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

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

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

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

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

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

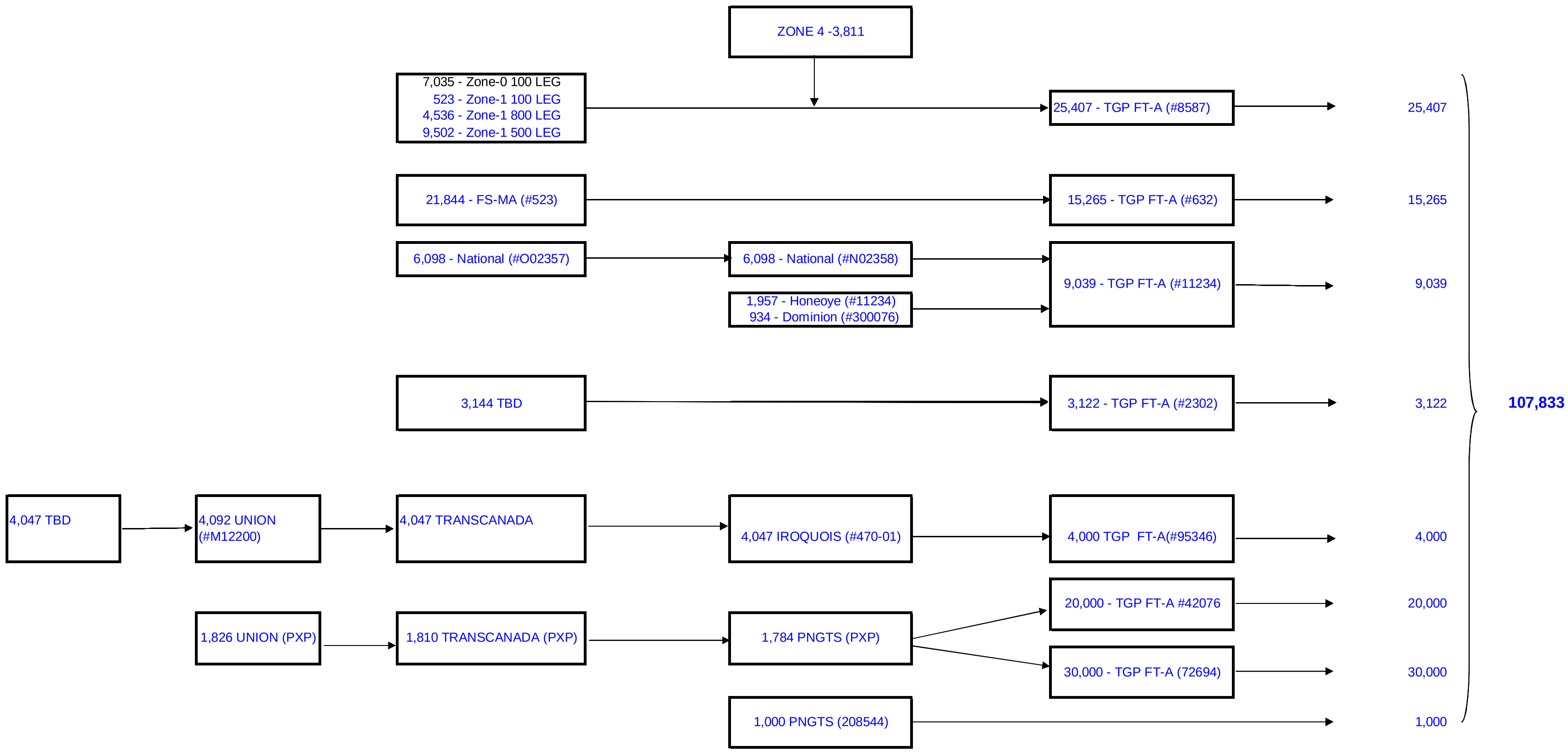
Please refer to the ENNGI 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Deborah Gilbertson
Sr. Manager, Energy Procurement

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

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



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

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Niagara	NA	NA	Supply	3,147	1,148,655	3/31/2019	N/A	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
ENGIE	FCS		Firm Combination Liquid and Vapor Svc	Up to 10 trucks	730,000	3/31/2019 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2019	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2019	N/A	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/A	
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2021	3/31/2019	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2020	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2022	11/1/2021	Evergreen Provision
Portland Natural Gas Transmission System	FT	208544	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	1,784	651,160	11/1/2019		Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2021	11/30/2020	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2020	10/31/2019	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2022	10/31/2021	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	1,810	660,650	11/1/2019		Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2022	10/31/2020	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	1,826	666,490	11/1/2019		Precedent Agreement

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

May 2017 - Apr 2018 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	17,503,533	44.21%	74.78%
G-42	12,021,109	30.36%	37.32%
G-43	2,980,868	7.53%	26.68%
G-51	2,767,315	6.99%	72.79%
G-52	2,732,036	6.90%	29.44%
G-53	1,147,046	2.90%	10.71%
G-54	437,495	1.11%	2.32%
Total C/I	39,589,403	100.00%	

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

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

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**				
2	**Peak 2018 - 2019 Winter Cost of Gas Filing**				
3					
4	**Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year**				
5					
6					
7		**Off-Peak**	**Peak**	**Total**	
8		**May 17 - Oct 17**	**Nov 17-Apr 18**	**May 17 - Apr 18**	
9		(Therms)	(Therms)	(Therms)	
10	Pipeline Deliveries	17,319,900	88,967,680	106,287,580	
11	All Others	96,140	2,172,350	2,268,490	
12		17,416,040	91,140,030	108,556,070	
13					**Ratio**
14	Total Winter Supplies				91,140,030
15	Total Pipeline Deliveries				106,287,580
16					
17	Ratio Winter Supplies to Pipeline Supplies				0.857

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

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

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

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

6 **Underground Storage Gas**

Ln	Description	Reference	May-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
9	Beginning Balance (MMBtu)		488,910	744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	488,910
11	Injections (MMBtu)	Sch 11A ln 38 /10	261,143	221,871	271,295	250,468	250,468	250,468	226,287	-	-	-	-	-	1,731,999
13	Subtotal		750,053	966,045	1,232,745	1,478,020	1,728,487	1,978,955	2,205,242	2,032,757	1,620,686	1,107,337	596,478	224,165	
15	Storage Sale/Adjustments		(3,639)	(4,595)	(5,193)			-							
17	Withdrawals (MMBtu)	Sch 11A ln 28 /10	(2,240)	-		-	-	-	(172,485)	(412,071)	(513,349)	(510,859)	(372,313)	(3,056)	(1,986,373)
19	Ending Balance (MMBtu)		744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	221,109	234,536
22	Beginning Balance		$ 1,154,733	$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	1,154,733
24	Injections	ln 11 * ln 36	$ 662,826	$ 532,338	$ 708,595	$ 674,472	$ 674,472	$ 674,472	$ 627,674	$ -	$ -	$ -	$ -	$ -	$ 4,554,849
26	Subtotal		$ 1,817,559	$ 2,344,415	$ 3,049,262	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,696,861	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	
28	Storage Sale/Adjustments		$ (28)	$ (3,747)	$ (3,491)			$ -							
30	Withdrawals	ln 17 * ln 34	$ (5,454)		$ -	$ -	$ -	$ -	$ (445,586)	$ (1,064,513)	$ (1,326,148)	$ (1,319,717)	$ (961,805)	$ (7,894)	(5,131,118)
32	Ending Balance		$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	$ 571,197	$ 578,464
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4232	$2.4268	$2.4736	$2.5170	$2.5425	$2.5615	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$2.5382	$2.3993	$2.6119	$2.6928	$2.6928	$2.6928	$2.7738	$2.8701	$2.9440	$2.9077	$2.8132	$2.6365	
38	For Informational Purposes								Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
39	Summer Hedge Contracts - Vols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX								$2.9479	$3.0421	$3.1275	$3.0909	$2.9866	$2.6741	
43	Hedged Volumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX								-	-	-	-	-	-	-
45	Hedge (Savings)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Month Dollar Average	ln (22 + ln 32) /2				$ 3,383,007	$ 4,057,479	$ 4,731,951	$ 5,160,231	$ 4,719,018	$ 3,523,688	$ 2,200,755	$ 1,059,994	$ 575,144	
49	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%	
51	Inventory Finance Charge	ln 47 * ln 49				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
52	Financial Expenses					0	0	0	0	0	0	0	0	0	
53	Total Inventory Finance Charges					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Ln			May-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
39															
40	**Liquid Propane Gas (LPG)**														
43	Beginning Balance		94,161	93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	94,161
44															
45	Injections	Sch 11A ln 37 /10	-	-	42	-	-	-	-	-	35,622	9,133	-	-	44,797
46															
47	Subtotal		94,161	93,982	93,945	93,945	93,945	93,945	93,945	93,945	129,567	52,741	43,608	43,608	
48															
49	Withdrawals	Sch 11A ln 32 /10	(179)	(79)	-	-	-	-	-	-	(85,959)	(9,133)	-	-	(95,350)
50															
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	43,608	43,608
54															
55															
56	Beginning Balance		$ 1,299,502	$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 1,299,502
57															
58	Injections	ln 45 * ln 68	-	-	580	-	-	-	-	-	491,582	126,033	-	-	618,195
59															
60	Subtotal		$ 1,299,502	$ 1,297,032	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,788,103	$ 727,852	$ 601,814	$ 601,814	
61															
62	Withdrawals	ln 51 * ln 66	(2,470)	(1,090)	-	-	-	-	-	-	(1,186,284)	(126,038)	-	-	(1,315,883)
63															
64	Ending Balance		$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 601,814	$ 601,814
65															
66	Average Rate For Withdrawals		$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8006	$13.8005	$13.8005	$13.8005	
67															
68	Propane Rate for Injections	Actual or Sch. 6, ln 158 * 10	$13.8009	$13.8009	$13.8009	$0.0000	$0.0000	$0.0000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	
69															
70															
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 949,170	$ 601,817	$ 601,814	$ 601,814	
72															
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
74															
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
76															
77															
78															
70															

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-18	6,295,834	$0.0005	$ 3,273
Dec-18	7,906,710	0.0005	4,111
Jan-19	9,791,817	0.0005	5,091
Feb-19	10,106,599	0.0005	5,254
Mar-19	9,033,498	0.0005	4,696
Apr-19	7,609,960	0.0005	3,956
Total	**50,744,418**		**$ 26,381**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed First Revised Page 94 for calculation of rate.

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
Lost Revenue Adjustment Mechanism

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

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

Schedule 19
RDAC

EnergyNorth Natural Gas Inc

2016 Customers (Equivalent Bills)

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

2016 Calendar BF Base Normal Revenue Adjusted

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

Base Revenue Per Customer

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

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

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

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

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

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

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

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

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

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

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

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

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

Total 11/2018 - 10/2019

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

0575 127

Environmental Surcharge - Manufactured Gas Plants

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

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

NASHUA FORMER MGP

LINE
NO.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.
- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.
- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.
- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.
- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.
- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.
- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.
- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.
- ENGI submitted a letter to NHDES in August 2000 discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and PSNH/NU, along with a proposed schedule for implementation of the work.
- NHDES approved the Revised Phase II Work Plan for the site at the end of August 2000.
- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.
- ENGI submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June 2001.

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

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

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

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

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

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

NASHUA FORMER MGP

LINE
NO.

completed in October 2004 and the Remedial Completion Report, submitted to NHDES in January 2005, was subsequently approved.

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

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

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

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

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

- 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.

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. DNAPL recovery is on-going. A Groundwater Management Permit was granted on June 5, 2014. A RAP Summary, involving the asphalt capping of the area over Holder #2 and continued groundwater monitoring, was submitted on April 2, 2015. A Monitoring Summary and Progress Report was submitted by ENGI on February 7, 2015. NHDES accepted the RAP Summary on April 10, 2015, with the provisions that ENGI submit the draft Activity and Use Restriction (AUR) and final engineering design plan for the cap by September 15, 2015. ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. NHDES responded to ENGI with their comments on December 15, 2016. Design for the engineered cap remedy is progressing, and when the design is completed it will be submitted to NHDES for approval. The cap construction and site paving are now planned for 2019 construction season.

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

NASHUA FORMER MGP

LINE
NO.

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.

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

MANCHESTER FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

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

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

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

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments. In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage. In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence. NHDES approved the ravine sign language in April 2002.

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

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

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

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

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

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers from April 2003 until the regular meetings ended on November 15, 2004. ENGI had

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attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided incurring costs associated with another entity's contamination.

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

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

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

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

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the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

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

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

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

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

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

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

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

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

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

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

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan (RAP) for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A RAP for the upland portion of the site was submitted to NHDES for review on June 30, 2010. NHDES issued its approval of the RAP for the upland portion of the site in a letter dated April 11, 2011. The Remedial Design Report summarizing the activities for addressing on-site and off-site impacts was submitted on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions. ENGI addressed these concerns and implemented the remedial activities on-site and off-site in 2017.

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

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

   Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier paid ENGI's attorneys fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States

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

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

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LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

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

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

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

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

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

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

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

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On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modelling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. In October 2010, NHDES issued a Preliminary Decision on RAP Addendum No. 2, in which NHDES indicated that it did not concur with ENGI's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. On January 28, 2011, ENGI submitted a comment letter to NHDES further explaining its rationale for the remedial alternative recommended in RAP Addendum No. 2. On November 2, 2011 NHDES announced a Final Decision indicating that it did not concur with ENGI's recommended remedial approach and selecting the full removal option as the remedy for the site. On December 2, 2011, ENGI filed an appeal of the NHDES Final Decision with the New Hampshire Waste Management Council. In March 2012, ENGI attended the Pre-Conference Hearing with the Council related to the appeal. Hearings on the matter were scheduled for October 18 and November 15, 2012. On July 26, 2012, the Hearing Officer granted an Assented to Motion to Continue the hearing until a date after January 3, 2013.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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CONCORD FORMER MGP

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

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

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

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

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

On July 15, 2003, NHDES issued a letter to ENGI requesting submission of a schedule and scope of work for a site investigation of the MGP site by mid-September 2003. ENGI proposed a May 2005 date for submission of a Site Investigation Report for the MGP site on Gas Street to NHDES by way of a letter dated October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will

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NO.

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

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling, along with further investigation of the brick tar sewer. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted in August 2013, in preparation for submittal of the Remedial Action Plan. This Supplement Data Collection Report was accepted by NHDES on October 24, 2013, and ENGI was authorized to prepare a RAP and Groundwater Management Permit (GMP) application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014.

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

CONCORD FORMER MGP

LINE
NO.

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

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

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

<u>Concord Pond</u>: ENGI has continued to monitor groundwater semi-annually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003, 2007 and 2012, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the

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

CONCORD FORMER MGP

LINE
NO.

future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan (RAP) which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase.

The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location.

ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. Contact was reconvened with the City in 2013, and adjustments to the original design were made to address outfall maintenance and access concerns of the City and NHDOT, respectively. The design was presented to the City on January 26, 2016. A rigorous schedule toward construction in late summer 2017 was agreed to by ENGI and the City in February 2016. The City did not meet an early deadline to determine and communicate details regarding access to their storm water system. Communication was again resumed in July 2016 by the City, however the City remained unresponsive to ENGI on implementation of the joint remedial design.

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

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond. During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste

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

CONCORD FORMER MGP

LINE
NO.

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

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. Based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river. ENGI met with NHDES on February 20, 2013 to discuss all sampling activities to date, summarized in an SIR Addendum Report, submitted in June 2013.

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

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE:

Concord MGP: In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. The Supplemental Data Collection report summarizing the investigation activities was accepted in October 2013, authorizing ENGI to prepare a RAP and GMP Application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed RAP, and NHDES approved the RAP with conditions. A Remedial Design Report, summarizing pre-design investigations, is to be provided to NHDES by the end of 2015.

Concord Pond: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit

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

CONCORD FORMER MGP

LINE
NO.

was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI. ENGI met with these parties on several occasions in 2010 and 2011. The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. The design was adjusted to accommodate the City's desire to simplify maintenance of the storm water system, however ENGI has received no response from the City after numerous attempts to begin the implementation

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

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

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

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

2018 SUMMARY BY SITE

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

REDACTED

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

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

REDACTED

159
0607

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

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

REDACTED

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

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CLEAN HARBORS	1002010900					530.46	530.46			530.46
2	CLEAN HARBORS	1002009730					277.20	277.20			277.20
[redacted]											
4	GZA GEOENVIRONMENTAL INC	744589		26,730.07				26,730.07			26,730.07
5	PLANT INSPECTORS FOR REMEDIATION ACTIVITIES				3,753.43			3,753.43			3,753.43
6	ESMI OF NH	1015191			90,828.00			90,828.00			90,828.00
7	MARY CASEY - MILEAGE	JC8825					53.93	53.93			53.93
8	MARY CASEY - MILEAGE	JC8825					166.72	166.72			166.72
9	CLEAN HARBORS	1002057075					8,308.52	8,308.52			8,308.52
10	T FORD COMPANY, INC	1806-1			90,930.00			90,930.00			90,930.00
11	CLEAN HARBORS	1002064356					277.20	277.20			277.20
12	ESMI OF NH	1015242			2,590.08			2,590.08			2,590.08
13	CLEAN HARBORS	1002139193					2,204.40	2,204.40			2,204.40
14	GZA GEOENVIRONMENTAL INC	750011		48,029.02				48,029.02			48,029.02
15	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 0118					839.09	839.09			839.09
[redacted]											
18	GZA GEOENVIRONMENTAL INC	749333		17,521.62				17,521.62			17,521.62
19	ESMI OF NH	1015428			10,368.40			10,368.40			10,368.40
20	ESMI OF NH	1015617			3,030.10			3,030.10			3,030.10
21	GZA GEOENVIRONMENTAL INC	753031		28,062.90				28,062.90			28,062.90
22	ESMI OF NH	1015717			2,052.40			2,052.40			2,052.40
23	GZA GEOENVIRONMENTAL INC	749019		78,038.61				78,038.61			78,038.61
[redacted]											
25	GZA GEOENVIRONMENTAL INC	755534		11,812.55				11,812.55			11,812.55
26	MARY CASEY - MILEAGE	JC10420					31.23	31.23			31.23
27	GZA GEOENVIRONMENTAL INC	757697		6,629.13				6,629.13			6,629.13
[redacted]											
29	6/30/18 ACCRUAL			36,000.00				36,000.00			36,000.00
30	Environmental Staff Time						$ 1,659.75	1,659.75			1,659.75
	Total Pool Activity		**0.00**	**252,823.90**	**203,552.41**	**0.00**	**14,348.50**	**470,724.81**	**0.00**	**(124,681.32)**	**346,043.49**

REDACTED

161

0609

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	**VENDOR**	**REF NO.**	**LEGAL EXPENSES**	**CONSULTING EXPENSES**	**REMEDIATION EXPENSES**	**SETTLEMENT EXPENSES**	**OTHER EXPENSES**	**SUBTOTAL EXPENSES**	**INSURANCE & THIRD PARTY EXPENSE**	**INSURANCE & THIRD PARTY RECOVERIES**	**TOTAL SUBMITTED**
1	ALLEGRA MARKETING PRINT MAIL	31130					180.00	180.00			180.00
2	MARY CASEY - MILEAGE	JC8825					49.69	49.69			49.69
3	MARY CASEY - MILEAGE	LABOR					50.37	50.37			50.37
4								0.00			0.00
5								0.00			0.00
6	Environmental Staff Time						10,519.21	10,519.21			10,519.21
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**10,799.27**	**10,799.27**	**0.00**	**0.00**	**10,799.27**

162
0610

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

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

REDACTED

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0611

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Concord Pond

		(thru 9/99) pool #1 #3	(9/99 9/00) pool #4	(9/03 9/04) pool #5	(9/04 9/05) pool #6	(9/05 9/06) pool #7	(9/06 9/07) pool #8	(9/07 9/08) pool #9	(9/08 9/09) pool #10	(9/09 9/10) pool #11	(9/10 9/11) pool #12	(9/11 9/12) pool #13	(9/12 6/13) pool #14	(7/13 6/14) pool #15	(7/14 6/15) pool #16	(7/15 6/16) pool #17	(7/16 6/17) pool #18	DEF056 (7/17 6/18) pool #19	subtotal
1	1 Remediation costs (i.o. 500061)	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
2	Remediation costs (i.o. 500005)	-	-																-
3	A Subtotal - remediation costs	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
4																			-
5	Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,204,671)
6	Cash recoveries (i.o. 500004)	(445,985)	-																(445,985)
7	Recovery costs (i.o. 500004)	623,784	-				-	-	-	-	-	-	-	-	-	-	-	-	623,784
8	Transfer Credit from Gas Restructuring																		-
9	B Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,026,872)
10																			-
11	A-B Total net expenses to recover	3,583,912	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	216,743	81,238	59,069	32,324	78,235	34,590	88,148	127,356	5,051,537
12																			-
13																			-
14	Surcharge revenue:																		-
15	Act June 1998 - October 1998	(54,889)	-																(54,889)
16	Act November 1998 - October 1999	(538,143)	-																(538,143)
17	Act November 1999 - October 2000	(760,871)	-																(760,871)
18	Act November 2000 - October 2001	(626,614)	(13,925)																(640,539)
19	Act November 2001 - October 2002	(600,600)	(24,514)																(625,114)
20	Act November 2002 - October 2003	(592,678)	(15,197)																(607,874)
21	Act November 2003 - October 2004	(291,340)	(14,567)																(305,907)
22	Act November 2004- October 2005	(56,719)	(14,180)	(14,180)															(85,078)
23	Act November 2005- October 2006	-	(6,875)	(6,875)															(13,750)
24	Act November 2006- October 2007	-	-	-	-	(14,091)													(14,091)
25	Act November 2007- October 2008																		-
26	Act November 2012- October 2013										(5,002)	(5,002)							(10,003)
27	Act November 2013- October 2014										(12,749)	(12,749)							(25,497)
28	Act Nov 2009-Oct 2010 Base Rate Rev										($4,423)								(4,423)
29	Act Nov 2010-Oct 2011 Base Rate Rev										($32,310)								(32,310)
30	Act Nov 2011-Oct 2012 Base Rate Rev										($28,448)								(28,448)
31	Act Nov 2012-Oct 2013 Base Rate Rev										($2,143)	($2,143)							(4,286)
32	Act Nov 2013-Oct 2014 Base Rate Rev																		-
33	Act Nov 2014-Oct 2015 Base Rate Rev																		
34	AES collections			(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(220,792)
35	Gas Street overcollection	(23,511)																	(23,511)
36	Prior Period Pool under/overcollection	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	-	-	-	-	-	-	-	-	-	
37																			0
38																			-
39	C Surcharge Subtotal	(3,524,326)	(50,710)	(9,559)	39,108	34,729	104,437	234,166	(12,904)	(13,145)	(98,295)	(33,631)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(3,995,526)
40																			
41																			
42	D Net balance to be recovered (A-B+C)	59,586	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	47,629	47,608	45,345	18,376	64,062	20,185	73,484	112,498	1,056,012
43																			
44	E Allocation of Litigated Recovery			-		-		(329,540)	(102,675)	(123,791)	(47,228)	-	-	-	-	-	-	-	(603,234)
45																			
46	Surcharge calculation																		
47	Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	6,801	12,956	7,875	36,607	14,417.84	62,986.49	112,498.35	254,142
48	remaining life	-	-	24	36	48	60	72	84	84	84	12	24	36	48	60	72	84	
49	one year	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
51																			
52	Required annual increase in rates:																		
53	smaller of D or F	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
54																			
55	forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																			
57	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0003

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

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

	i.o. no. 500005 (thru 9/01) pool #1 _ #3	(9/04 9/05) pool #4	(9/05 9/06) pool #5	(9/06 9/07) pool #6	(9/07 9/08) pool #7 Incl. Audit Corr	(9/08 9/09) pool #8 Incl. Audit Corr	(9/09 9/10) pool #9	(9/10 9/11) pool #10	(9/11 9/12) pool #11	(9/12 6/13) pool #12	(7/13 6/14) pool #13	(7/14 6/15) pool #14	(7/15 6/16) pool #15	(7/16 6/17) pool #16	DEF086 (7/17 6/18) pool #17	subtotal
1 Remediation costs (i.o. 500061)	-	-									[redacted]					
Remediation costs (i.o. 500005)	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
A Subtotal - remediation costs	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
Cash recoveries (i.o. 500061)	-	-	-	-	-	-										
Cash recoveries (i.o. 500004)	-	-	-	-	-	-										
Recovery costs (i.o. 500004)	-			11,643	21,729	-	-									
Transfer Credit from Gas Restructuring				-	-	-										
B Subtotal - net recoveries	-	-	-	11,643	21,729	-	-	-	-	-						
A-B Total net expenses to recover	5,241,032	9,702	2,330,555	2,100,842	449,954	607,876	262,678	210,532	269,281	642,986						
Surcharge revenue:																
Act June 1998 - October 1998	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
Act November 1998 - October 1999	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
Act November 1999 - October 2000	(151,933)	-	-		-	-	-	-	-	-	-	-	-	-	-	(151,933)
Act November 2000 - October 2001	(696,237)	-	-		-	-	-	-	-	-	-	-	-	-	-	(696,237)
Act November 2001 - October 2002	(796,714)	-	-		-	-	-	-	-	-	-	-	-	-	-	(796,714)
Act November 2002 - October 2003	(805,434)	-	-		-	-	-	-	-	-	-	-	-	-	-	(805,434)
Act November 2003 - October 2004	(699,215)															(699,215)
Act November 2004- October 2005	(652,264)															(652,264)
Act November 2005- October 2006	(691,159)	-	-		-	-	-	-	-	-	-	-	-	-	-	(691,159)
Act November 2006- October 2007	(648,174)	-	(309,996)													(958,171)
Act November 2007- October 2008																-
Act November 2012- October 2013									(20,006)							(20,006)
Act November 2013- October 2014									(25,497)	(76,491)						(101,988)
Act Nov 2009-Oct 2010 Base Rate Rev								($4,296)								(4,296)
Act Nov 2010-Oct 2011 Base Rate Rev								($31,384)								(31,384)
Act Nov 2011-Oct 2012 Base Rate Rev								($27,632)								(27,632)
Act Nov 2012-Oct 2013 Base Rate Rev								$0	($14,208)							(14,208)
Act Nov 2013-Oct 2014 Base Rate Rev									(28,433)	(28,433)	(28,433)					(85,298)
Act Nov 2014-Oct 2015 Base Rate Rev									(21,909)	(21,909)	(21,909)	(21,909)	-	-	-	(87,637)
AES collections																-
Gas Street overcollection																-
Prior Period Pool under/overcollection	21,391	111,336	121,038	2,141,596	4,242,438		-	-	(89,606)	-	-	-	-	-	-	
C Surcharge Subtotal	(5,119,739)	111,336	(188,958)	2,141,596	4,242,438	-	-	(63,313)	(199,659)	(126,833)	(50,342)	(21,909)	-	-	-	(5,823,577)
D Net balance to be recovered (A-B+C)	121,293	121,038	2,141,596	4,242,438	4,692,393	607,876	262,678	147,219	69,622	516,153	[redacted]					
E Allocation of Litigated Recovery					(4,692,393)	(607,876)	(262,678)	(236,825)	-	-						
Surcharge calculation																
Unrecovered costs (D+E)	-	-			-	-	-	-	9,946	147,472.25						
remaining life	-	36	48	60	72	84	84	48	12	24						
one year	-	12	12	12	12	12	12	12	12	12						
F amortization	-	-	-	-	-	-	-	-	9,946	73,736						
Required annual increase in rates:																
smaller of D or F	-	-	-		-	-	-	-	9,946	73,736	[redacted]					
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0004	[redacted]					

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Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
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Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Manchester

		(9/00 9/03) pool #1 #3	(9/03 9/04) pool #4	(9/04 9/05) pool #5	(9/05 9/06) pool #6	(9/06 9/07) pool #7	(9/07 9/08) pool #8	(9/08 9/09) pool #9	(9/09 9/10) pool #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	DEF057 (7/17 6/18) pool #18	subtotal
							Incl. Audit Corr											
1	1 Remediation costs (i.o. 500061)	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	10,598,402
2	Remediation costs (i.o. 500005)	825,092																825,092
3	A Subtotal - remediation costs	825,092	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	11,423,494
4																		
5	Cash recoveries (i.o. 500061)	-			(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(2,753,952)
6	Cash recoveries (i.o. 500004)	-																-
7	Recovery costs (i.o. 500004)	-	1,242,326			2,546	-											1,244,872
8	Transfer Credit from Gas Restructuring					-	-											-
9	B Subtotal - net recoveries	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(1,509,080)
10																		
11	A-B Total net expenses to recover	825,092	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,589	442,298	(188,619)	61,210	75,440	22,690	50,523	346,043	9,914,414
12																		-
13																		-
14	Surcharge revenue:																	-
15	Act June 1998 - October 1998	-	-															-
16	Act November 1998 - October 1999	-	-															-
17	Act November 1999 - October 2000	-	-															-
18	Act November 2000 - October 2001	-	-															-
19	Act November 2001 - October 2002	(73,543)	-															(73,543)
20	Act November 2002 - October 2003	(75,984)	-															(75,984)
21	Act November 2003 - October 2004	(138,576)	-															(138,576)
22	Act November 2004- October 2005	(113,437)	(212,695)	-			-	-	-	-	-	-	-	-	-	-	-	(326,132)
23	Act November 2005- October 2006	(96,247)	(206,243)	(261,242)			-	-	-	-	-	-	-	-	-	-	-	(563,732)
24	Act November 2006- October 2007	(126,817)	(211,361)	(281,815)	(42,272)													(662,265)
25	Act November 2007- October 2008																	-
26	Act November 2012- October 2013										(40,012)							(40,012)
27	Act November 2013- October 2014										(50,994)							(50,994)
28	Act Nov 2009-Oct 2010 Base Rate Rev									-								-
29	Act Nov 2010-Oct 2011 Base Rate Rev									-								-
30	Act Nov 2011-Oct 2012 Base Rate Rev									-								-
31	Act Nov 2012-Oct 2013 Base Rate Rev									-	(23,337)							(23,337)
32	Act Nov 2013-Oct 2014 Base Rate Rev																	-
33	Act Nov 2014-Oct 2015 Base Rate Rev																	
34	AES collections																	-
35	Gas Street overcollection																	-
36	Prior Period Pool under/overcollection	394,600	276,881	1,224,246	2,671,037	2,958,927	3,302,330	-	-	-								
37																		
38																		
39	C Surcharge Subtotal	(230,004)	(353,418)	681,189	2,628,765	2,958,927	3,302,330	-	-	-	(114,343)	-	-	-	-	-	-	(1,954,576)
40																		
41																		
42	D Net balance to be recovered (A-B+C)	595,088	1,224,246	2,671,037	2,958,927	3,302,330	6,562,539	312,185	328,678	137,589	327,955	(188,619)	61,210	75,440	22,690	50,523	346,043	7,959,838
43																		
44	E Allocation of Litigated Recovery		-	-			(6,562,539)	(312,185)	(328,678)	(91,770)	-	-	-	-	-	-	-	(7,295,172)
45																		
46	Surcharge calculation																	
47	Unrecovered costs (D+E)	-	-	-	-		-	-	-	-	46,851	(53,891)	26,233	43,108	16,207	43,305	346,043	467,856
48	remaining life	-	24	36	48	60	70	84	84	12	12	24	36	48	60	72	84	
49	one year	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	-	-	-	-	-	-	-	-	-	46 851	(26 946)	8 744	10 777	3 241	7 218	49 435	
51																		
52	Required annual increase in rates:																	
53	smaller of D or F	-	-	-	-		-	-	-	-	46,851	(26,946)	8,744	10,777	3,241	7,218	49,435	99,320
54																		
55	forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																		
57	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003	$0.0005

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Nashua																
					Corrected per 2/08 Audit											DEF054	
	(9/00 9/03) pool #1 #3	(9/03 9/04) pool #4	(9/04 9/05) pool #5	(9/05 9/06) pool #6	(9/06 9/07) pool #7	(9/07 9/08) pool #8	(9/08 9/09) pool #9	(9/09 9/10) pool #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	(7/17 6/18) pool #18	subtotal
1 Remediation costs (i.o. 500061)	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	1,620,044
Remediation costs (i.o. 500005)	1,771,567																1,771,567
A Subtotal - remediation costs	1,771,567	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	3,391,611
																	-
Cash recoveries (i.o. 500061)	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(566,063)
Cash recoveries (i.o. 500004)	-																-
Recovery costs (i.o. 500004)	-			5,449	12,938	-	-										18,388
Transfer Credit from Gas Restructuring					-	-	-										-
B Subtotal - net recoveries	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(547,675)
																	-
A-B Total net expenses to recover	1,771,567	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,351	396,411	(80,241)	35,950	65,217	62,435	85,314	15,523	2,843,936
Surcharge revenue:																	
Act June 1998 - October 1998	-	-															-
Act November 1998 - October 1999	-	-															-
Act November 1999 - October 2000	-	-															-
Act November 2000 - October 2001	-	-															-
Act November 2001 - October 2002	(183,857)	-															(183,857)
Act November 2002 - October 2003	(243,150)	-															(243,150)
Act November 2003 - October 2004	(247,639)	-															(247,639)
Act November 2004- October 2005	(241,054)	-															(241,054)
Act November 2005- October 2006	(247,492)	-	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(274,991)
Act November 2006- October 2007	(253,633)	-	(28,181)	-													(281,815)
Act November 2007- October 2008																	-
Act November 2012- October 2013										(40,012)							(40,012)
Act November 2013- October 2014										(38,246)							(38,246)
Act Nov 2009-Oct 2010 Base Rate Rev									-								-
Act Nov 2010-Oct 2011 Base Rate Rev									-								-
Act Nov 2011-Oct 2012 Base Rate Rev									-								-
Act Nov 2012-Oct 2013 Base Rate Rev									-	(20,916)							(20,916)
Act Nov 2013-Oct 2014 Base Rate Rev																	-
Act Nov 2014-Oct 2015 Base Rate Rev																	
AES collections																	-
Gas Street overcollection																	-
Prior Period Pool under/overcollection	669,664	543,205	554,046	704,732	714,955	733,479	-	-	-	6,224	-	-	-	-	-	-	
C Surcharge Subtotal	(747,161)	543,205	498,365	704,732	714,955	733,479	-	-	-	(92,950)	-	-	-	-	-	-	(1,571,680)
D Net balance to be recovered (A-B+C)	1,024,405	554,046	704,732	714,955	733,479	830,669	16,289	98,975	33,351	303,461	(80,241)	35,950	65,217	62,435	85,314	15,523	1,272,256
E Allocation of Litigated Recovery	-	-	-	-	-	(830,669)	(16,289)	(98,975)	(27,127)	-	-	-	-	-	-	-	(973,061)
Surcharge calculation																	
Unrecovered costs (D+E)	-	-	-	-		-	-	-		43,352	(22,926)	15,407	37,267	44,596	73,126	15,523	206,345
remaining life	12	24	36	48	60	72	84	84	72	12	24	36	48	60	72	84	
one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	43 352	(11 463)	5 136	9 317	8 919	12 188	2 218	
Required annual increase in rates:																	
smaller of D or F	-	-	-	-		-	-	-	-	43,352	(11,463)	5,136	9,317	8,919	12,188	2,218	69,665
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0004

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Dover												
												DEF059	
	(9/02 9/03) pool #1	(9/04 9/05) pool #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/17 6/18) pool #12	subtotal
1 Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	-	-	-	-	-	-	21,142
Remediation costs (i.o. 500005)	181,066												181,066
A Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	-	-	-	-	-	-	202,208
Cash recoveries (i.o. 500061)	-					-	-	-	-	-	-	-	-
Cash recoveries (i.o. 500004)	-												-
Recovery costs (i.o. 500004)	-												-
Transfer Credit from Gas Restructuring													-
B Subtotal - net recoveries	-	-	-	-	-	-	-	-	-	-	-	-	-
A-B Total net expenses to recover	181,066	18,854	2,288	-	-	-	-	-	-	-	-	-	202,208
Surcharge revenue:													
Act June 1998 - October 1998	-												-
Act November 1998 - October 1999	-												-
Act November 1999 - October 2000	-												-
Act November 2000 - October 2001	-												-
Act November 2001 - October 2002	-												-
Act November 2002 - October 2003	-												-
Act November 2003 - October 2004	(29,134)												(29,134)
Act November 2004- October 2005	(28,359)												(28,359)
Act November 2005- October 2006	(27,499)	-			-	-	-	-	-	-	-	-	(27,499)
Act November 2006- October 2007	(28,181)	-	-										(28,181)
Act November 2007- October 2008													-
Act November 2012- October 2013													-
Act November 2013- October 2014													-
Act Nov 2009-Oct 2010 Base Rate Rev													-
Act Nov 2010-Oct 2011 Base Rate Rev													-
Act Nov 2011-Oct 2012 Base Rate Rev													-
Act Nov 2012-Oct 2013 Base Rate Rev													-
Act Nov 2013-Oct 2014 Base Rate Rev													-
Act Nov 2014-Oct 2015 Base Rate Rev													
AES collections													-
Gas Street overcollection													-
Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-	-	-	-	-	-	-	
C Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	-	-	-	-	-	-	(113,174)
D Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	-	-	-	-	-	-	89,034
E Allocation of Litigated Recovery		-		-	(89,034)	-	-	-	-	-	-	-	(89,034)
Surcharge calculation													
Unrecovered costs (D+E)	-	-	-		-	-	-	-	-	-	-	-	-
remaining life	24	36	48	60	72	84	84	84	84	84	84	84	
one year	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	-	-	-	
Required annual increase in rates:													
smaller of D or F	-	-	-		-	-	-	-	-	-	-	-	-
forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		Keene												
													DEF055	
		(9/03 9/04) pool #1	(9/04 9/05) pool #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	subtotal
1	Remediation costs (i.o. 500061)	-										[redacted]		
	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
	Cash recoveries (i.o. 500061)	-												
	Cash recoveries (i.o. 500004)	-												
	Recovery costs (i.o. 500004)			18,831	823	-	-	-	-					
	Transfer Credit from Gas Restructuring				-	-	-							
B	Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-			
A-B	Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400			
														-
														-
	Surcharge revenue:													-
Act	June 1998 - October 1998	-												-
Act	November 1998 - October 1999	-												-
Act	November 1999 - October 2000	-												-
Act	November 2000 - October 2001	-												-
Act	November 2001 - October 2002	-												-
Act	November 2002 - October 2003	-												-
Act	November 2003 - October 2004	-												-
Act	November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
Act	November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
Act	November 2006- October 2007	-	-	(14,091)										(14,091)
Act	November 2007- October 2008													-
Act	November 2012- October 2013													-
Act	November 2013- October 2014													-
Act	Nov 2009-Oct 2010 Base Rate Rev													-
Act	Nov 2010-Oct 2011 Base Rate Rev													-
Act	Nov 2011-Oct 2012 Base Rate Rev													-
Act	Nov 2012-Oct 2013 Base Rate Rev													-
Act	Nov 2013-Oct 2014 Base Rate Rev													-
Act	Nov 2014-Oct 2015 Base Rate Rev													
	AES collections													-
	Gas Street overcollection													-
	Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	-	-	-	-	
C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	-	-	-	-	(14,091)
D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	488	1,400	[redacted]		
E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-			
	Surcharge calculation													
	Unrecovered costs (D+E)	-	-	-			-	-	-	70	400			
	remaining life	24	36	48	60	72	84	84	84	12	24			
	one year	12	12	12	12	12	12	12	12	12	12			
F	amortization	-	-	-	-	-	-	-	-	70	200			
	Required annual increase in rates:													
	smaller of D or F	-	-	-			-	-	-	70	200	[redacted]		
	forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		Concord														
			Corrected per 1/24/07 Audit	Corrected per 2/08 Audit											DEF077	
		(9/03 9/05) pool #1 & #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	(7/15 6/16) pool #13	(7/16 6/17) pool #14	(7/17 6/18) pool #15	subtotal
1	1 Remediation costs (i.o. 500061)	-												[redacted]		
2	Remediation costs (i.o. 500005)	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749			
3	A Subtotal - remediation costs	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749			
4																
5	Cash recoveries (i.o. 500061)	-	(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)			
6	Cash recoveries (i.o. 500004)	-														
7	Recovery costs (i.o. 500004)				1,432	(1,007)										
8	Transfer Credit from Gas Restructuring		-													
9	B Subtotal - net recoveries	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)			
10																
11	A-B Total net expenses to recover	243,123	22,106	61,665	(3,163)	92,679	46,190	168,338	257,528	45,384	123,355	163,783	95,553			
12																-
13																-
14	Surcharge revenue:															-
15	Act June 1998 - October 1998	-														-
16	Act November 1998 - October 1999	-														-
17	Act November 1999 - October 2000	-														-
18	Act November 2000 - October 2001	-														-
19	Act November 2001 - October 2002	-														-
20	Act November 2002 - October 2003	-														-
21	Act November 2003 - October 2004	-														-
22	Act November 2004- October 2005															-
23	Act November 2005- October 2006	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(27,499)
24	Act November 2006- October 2007	(28,181)	-													(28,181)
25	Act November 2007- October 2008															-
26	Act November 2012- October 2013							(20,006)	(20,006)							(40,012)
27	Act November 2013- October 2014							(12,749)	(25,497)							(38,246)
28	Act Nov 2009-Oct 2010 Base Rate Rev							($1,891)								(1,891)
29	Act Nov 2010-Oct 2011 Base Rate Rev							($13,816)								(13,816)
30	Act Nov 2011-Oct 2012 Base Rate Rev							($12,164)								(12,164)
31	Act Nov 2012-Oct 2013 Base Rate Rev							($6,794)	($6,794)							(13,588)
32	Act Nov 2013-Oct 2014 Base Rate Rev															-
33	Act Nov 2014-Oct 2015 Base Rate Rev															
34	AES collections															-
35	Gas Street overcollection															-
36	Prior Period Pool under/overcollection	22,191	187,442	209,549	271,214	-	-	-	-	-	-	-	-	-	-	
37																
38																
39	C Surcharge Subtotal	(33,490)	187,442	209,549	271,214	-	-	(67,420)	(52,297)	-	-	-	-	-	-	(175,398)
40																
41																
42	D Net balance to be recovered (A-B+C)	209,633	209,549	271,214	268,051	92,679	46,190	100,919	205,231	45,384	123,355	163,783	95,553	[redacted]		
43																
44	E Allocation of Litigated Recovery	-	-	-	(268,051)	(92,679)	(46,190)	(13,905)	-	-	-	-	-			
45																
46	Surcharge calculation															
47	Unrecovered costs (D+E)	-	-		-	-	-	-	29,319	12,967	52,866	93,590	68,252			
48	remaining life	84	60		72	84	84	12	12	24	36	48	60			
49	one year	24	12		12	12	12	12	12	12	12	12	12			
50	F amortization	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650			
51																
52	Required annual increase in rates:															
53	smaller of D or F	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650	[redacted]		
54																
55	forecasted therm sales	369,309,748	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																
57	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0001	$0.0001	$0.0001	[redacted]		

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		General																
			Corrected per 1/24/07 Audit												DEF064			2018 MGP Remediation
		(9/02 9/05) pool #1 #3	(9/05 9/06) pool #4	(9/06 9/07) pool #5	(9/07 9/08) pool #6	(9/08 9/09) pool #7	(9/09 9/10) pool #8	(9/10 9/11) pool #9	(9/11 9/12) pool #10	(9/12 6/13) pool #11	(7/13 6/14) pool #12	(7/14 6/15) pool #13	(7/15 6/16) pool #14	(7/16 6/17) pool #15	(7/17 6/18) pool #16	subtotal		subtotal
1	1 Remediation costs (i.o. 500061)	-														-		[redacted]
2	Remediation costs (i.o. 500005)	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
3	A Subtotal - remediation costs	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
4																		
5	Cash recoveries (i.o. 500061)	-		-	-	-										-		
6	Cash recoveries (i.o. 500004)	-														-		
7	Recovery costs (i.o. 500004)		290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	322,270		
8	Transfer Credit from Gas Restructuring	(3,331)	-													(3,331)		
9	B Subtotal - net recoveries	(3,331)	290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	318,939		
10																		
11	A-B Total net expenses to recover	746,908	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	73,846	13,139	(7,638)	11,879	6,547	10,799	1,218,366		
12																		
13																		-
14	Surcharge revenue:																	
15	Act June 1998 - October 1998	-														-		(54,889)
16	Act November 1998 - October 1999	-														-		(538,143)
17	Act November 1999 - October 2000	-														-		(912,804)
18	Act November 2000 - October 2001	-														-		(1,336,776)
19	Act November 2001 - October 2002	-														-		(1,679,228)
20	Act November 2002 - October 2003	-														-		(1,732,442)
21	Act November 2003 - October 2004	(8,265)														(8,265)		(1,428,735)
22	Act November 2004- October 2005	(70,898)														(70,898)		(1,403,787)
23	Act November 2005- October 2006	(96,247)			-	-	-	-	-	-	-	-	-	-	-	(96,247)		(1,694,877)
24	Act November 2006- October 2007		(49,318)													(49,318)		(2,036,113)
25	Act November 2007- October 2008															-		-
26	Act November 2012- October 2013							(5,002)	(5,002)							(10,003)		(160,048)
27	Act November 2013- October 2014							(12,749)	(12,749)	(12,749)						(38,246)		(293,217)
28	Act Nov 2009-Oct 2010 Base Rate Rev															-		(10,611)
29	Act Nov 2010-Oct 2011 Base Rate Rev															-		(77,509)
30	Act Nov 2011-Oct 2012 Base Rate Rev															-		(68,244)
31	Act Nov 2012-Oct 2013 Base Rate Rev															-		(76,335)
32	Act Nov 2013-Oct 2014 Base Rate Rev																	(85,298)
33	Act Nov 2014-Oct 2015 Base Rate Rev																	(87,637)
34	AES collections	-														-		(220,792)
35	Gas Street overcollection															-		(23,511)
36	Prior Period Pool under/overcollection	296,594	457,429	732,622	786,465	-	-	-	-	-	-	-	-	-	-			
37																		
38																		
39	C Surcharge Subtotal	15,503	408,111	732,622	786,465	-	-	(17,750)	(17,750)	(12,749)	-	-	-	-	-	(272,977)		(13,920,997)
40																		
41																		
42	D Net balance to be recovered (A-B+C)	762,410	732,622	786,465	621,477	(2,931)	4,199	51,536	61,217	61,098	13,139	(7,638)	11,879	6,547	10,799	945,390	3,595,226	[redacted]
43																	-	
44	E Allocation of Litigated Recovery	-	-	-	(621,477)	2,931	(4,199)	(11,582)	-	-	-	-	-	-	-	(634,326)	(428,437)	
45																	-	
46	Surcharge calculation																-	
47	Unrecovered costs (D+E)	-	-		-	-	-	-	8,745	17,456	5,631	(4,364)	8,485	5,611	10,799	52,364	2,150,415	
48	remaining life	84	60	72	84	84	84	12	12	24	36	48	60	72	84			
49	one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12			
50	F amortization	-	-	-	-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543			
51																		
52	Required annual increase in rates:																	
53	smaller of D or F	-	-		-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543	22,434	584,652	
54																		
55	forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874		**184,654,874**
56																		
57	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001		**$0.0161**

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

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

Expense and Collection Summary per Year

		(thru 9/98)	(9/99 9/00)	(9/00 9/01)	(9/01 9/02)	(9/02 9/03)	(9/03 9/04)	(9/04 9/05)	(9/05 9/06)	(9/06 9/07)	(9/07 9/08)	(9/08 9/09)	(9/09 9/10)	(9/10 9/11)	(9/11 9/12)	(7/13 6/14)	(7/14 6/15)	(7/15 6/16)	(7/16 6/17)	(7/17 6/18)	Total
1	Remediation costs (i.o. 500061)	5,420,852	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,515	993,434	196,611	312,039	220,344	256,871	670,904	[redacted]
	Remediation costs (i.o. 500005)	1,027,747	-	-	-	181,066	10,165	16,308	2,444,366	2,229,625	255,263	658,324	316,280	459,550	651,906	1,801,404	7,975,914	3,307,910	260,380	115,841	[redacted]
A	Subtotal - remediation costs	6,448,599	129,002	-	-	181,066	416,637	2,252,990	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,146,065	1,645,340	1,998,015	8,287,953	3,528,254	517,250	786,745	[redacted]
	Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(79,446)	(121,889)	(119,826)	(53,116)	(195,423)	[redacted]
	Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	-	-	[redacted]
	Recovery costs (i.o. 500004)	623,784	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	(14,068)	2,500,000	2,475,750	-	-	-	[redacted]
	Transfer Credit from Gas Restructuring	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]
B	Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	-	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	2,420,554	2,353,861	(119,826)	(53,116)	(195,423)	[redacted]
A-B	Total net expenses to recover	4,611,659	95,798	-	-	181,066	1,273,932	2,379,412	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	835,839	1,526,211	4,418,569.29	10,641,813.86	3,408,427.63	464,499.00	591,686.20	[redacted]
	Surcharge revenue:																				
Act	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act	November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act	November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act	November 2000 - October 2001	(779,786)	(13,925)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(793,711)
Act	November 2001 - October 2002	(759,943)	(24,514)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(784,457)
Act	November 2002 - October 2003	(744,646)	(15,197)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(759,843)
Act	November 2003 - October 2004	(422,442)	(14,567)	-	-	(29,134)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(466,143)
Act	November 2004- October 2005	(184,336)	(14,180)	-	-	(28,359)	(226,875)	-	-	-	-	-	-	-	-	-	-	-	-	-	(453,749)
Act	November 2005- October 2006	(141,176)	(6,875)	-	-	(27,499)	(213,118)	(288,741)	-	-	-	-	-	-	-	-	-	-	-	-	(677,409)
Act	November 2006- October 2007	-	-	-	-	(28,181)	(211,361)	(309,996)	(429,768)	-	-	-	-	-	-	-	-	-	-	-	(979,307)
Act	November 2007- October 2008													-	-	-	-	-	-	-	-
Act	November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	-	-	(160,048)
Act	November 2013- October 2014													(38,246)	(165,731)	-	-	-	-	-	(203,977)
Act	Nov 2009-Oct 2010 Base Rate Rev													(10,611)	-	-	-	-	-	-	(10,611)
Act	Nov 2010-Oct 2011 Base Rate Rev													(77,509)	-	-	-	-	-	-	(77,509)
Act	Nov 2011-Oct 2012 Base Rate Rev													(68,244)	-	-	-	-	-	-	(68,244)
Act	Nov 2012-Oct 2013 Base Rate Rev													(8,937)	(67,398)	-	-	-	-	-	(76,335)
Act	Nov 2013-Oct 2014 Base Rate Rev													-	(28,433)	(28,433)	-	-	-	-	(56,865)
Act	Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	(21,909)	(21,909)	-	-	-	(65,728)
	AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(207,067)
	Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
	Prior Period Pool under/overcollection																				
C	Surcharge Subtotal	(4,561,677)	(89,257)	-	-	(113,174)	(684,947)	(610,364)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(246,777)	(427,248)	(64,290)	(36,082)	(14,405)	(14,664)	(14,858)	(7,370,353)
D	Net balance to be recovered (A-B+C)	49,982	6,541	-	-	67,892	588,985	1,769,048	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	589,062	1,098,962	4,354,279	10,605,732	3,394,023	449,835	576,828	[redacted]
E	Allocation of Litigated Recovery																				
	Surcharge calculation																				
	Unrecovered costs (D+E)																				
	remaining life																				
	one year																				
F	amortization																				
	Required annual increase in rates:																				
	smaller of D or F																				
	forecasted therm sales																				
	surcharge per therm																				

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019

Rate: $0.19 /MMBtu

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Monthly Imbalances

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

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

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

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

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

Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		164,571	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 95346	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6) 72694	30,000		
10			79,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3 of 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		56,738	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,969,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$0		Attachment B Page 3 Line 1
27	Total		$6,949,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$122.48		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$20.41**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

Tennessee Allocations

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

Capacity Resources effective November 1, 2017

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

* All gas transferred for storage contracts will be based on LDC's monthly WACOG
**All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention Demand charge applicable for 6 months

Note **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/18. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the EnergyNorth Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $18.2633 /dth.

REDACTED
Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

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

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

REDACTED

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	**Storage**	**Peaking**	**Total**
G-41	**LAHW**	Low Annual C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	59.0%	13.6%	27.4%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	59.0%	13.6%	27.4%	100.0%

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD			71.386	
		Base load	**Heat load**	**Total**
HLF	**R-1 RNSH**	109	469	578
LLF	**R-3 RSH**	4,189	67,700	71,889
LLF	**G-41 SL**	1,045	29,440	30,485
HLF	**G-51 SH**	670	1,886	2,556
LLF	**G-42 ML**	1,566	36,248	37,813
HLF	**G-52 MH**	1,846	3,535	5,381
LLF	**G-43 LL**	587	6,881	7,468
HLF	**G-53 LLL90**	1,412	2,480	3,893
HLF	**G-54 LLG90**	382	4,126	4,507
	TOTAL	11,806	152,765	164,571
	HLF	4,420	12,496	16,916
	LLF	7,387	140,269	147,655
	Total	11,806	152,765	164,571

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	**Remaining Pipeline**	**Sub-total Pipeline**	**Storage**	**Peaking**	**Total**
R-1 RNSH	109	208	318	86	174.16	578
R-3 RSH	4,189	30,096	34,285	12,460	25,144	71,889
G-41 SL	1,045	13,087	14,133	5,418	10,934	30,485
G-51 SH	670	839	1,509	347	701	2,556
G-42 ML	1,566	16,114	17,680	6,671	13,463	37,813
G-52 MH	1,846	1,571	3,418	651	1,313	5,381
G-43 LL	587	3,059	3,646	1,266	2,556	7,468
G-53 LLL90	1,412	1,103	2,515	457	921	3,893
G-54 LLG90	382	1,834	2,216	759	1,532	4,507
TOTAL	11,806	67,912	79,718	28,115	56,738	164,571
HLF	4,420	5,555	9,975	2,300	4,641	16,916
LLF	7,387	62,356	69,743	25,815	52,097	147,655
Total	11,806	67,912	79,718	28,115	56,738	164,571

% of Peak Day Requirement

	Pipeline	**Storage**	**Peaking**	**Total**
R-1 RNSH	54 9%	14.9%	30.1%	100.0%
R-3 RSH	47.7%	17.3%	35.0%	100.0%
G-41 SL	46.4%	17.8%	35 9%	100.0%
G-51 SH	59.0%	13.6%	27.4%	100.0%
G-42 ML	46 8%	17.6%	35.6%	100.0%
G-52 MH	63 5%	12.1%	24.4%	100.0%
G-43 LL	48 8%	17.0%	34 2%	100.0%
G-53 LLL90	64.6%	11.7%	23.7%	100.0%
G-54 LLG90	49 2%	16.8%	34.0%	100.0%
TOTAL	48.4%	17.1%	34 5%	100.0%
High Load Factor	58.97%	13.60%	27.44%	100%
Low Load Factor	47.23%	17.48%	35.28%	100%
Total	48.44%	17.08%	34.48%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Allocate Design Day Sendout to Rate Classes

Design DD 71.386

	Daily Baseload * 1000	March Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	109	6.530	466	575	19%	0.307%	109	469	578
R-3 RSH	4,189	942.720	67,297	71,486	6%	44.317%	4,189	67,700	71,889
G-41 SL	1,045	409.946	29,264	30,310	3%	19.271%	1,045	29,440	30,485
G-51 SH	670	26.266	1,875	2,545	26%	1.235%	670	1,886	2,556
G-42 ML	1,566	504.747	36,032	37,598	4%	23.728%	1,566	36,248	37,813
G-52 MH	1,846	49.223	3,514	5,360	34%	2.314%	1,846	3,535	5,381
G-43 LL	587	95.816	6,840	7,427	8%	4.504%	587	6,881	7,468
G-53 LLL90	1,412	34.540	2,466	3,878	36%	1.624%	1,412	2,480	3,893
G-54 LLG90	382	57.448	4,101	4,483	9%	2.701%	382	4,126	4,507
TOTAL	11,806	2,294.712	151,855	163,661		100.000%	11,806	152,765	164,571

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

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

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	36	65	147	242	149	80	81	161	0	0	7	64	1,008
LLF	400	1,142	2,093	2,146	1,676	1,335	715	199	0	0	7	76	9,775
Actual BDD	**472.5**	**982.5**	**1219.5**	**1028.5**	**858.0**	**730.5**	**339.0**	**83.0**	**33.0**	**14.0**	**38.5**	**136.5**	5935 5

Heat Factors

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

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

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

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

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

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

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6.0%				$0.3927	$0.3722	$ 943.37	$ 926 93	$ 16.44	1.77%	$0 3927	$0.3736	$ 1,570 86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9.0%				$0.4724	$0.4628	$ 679.85	$ 672 22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161 81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20.0%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10 90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10 22%
4	Nov 01 - Apr 02	24.0%				$0.5141	$0.4818	$ 790.65	$ 760 55	$ 30.10	3 96%	$0 5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3 52%
5	Nov 02 - Apr 03	24.0%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2 27%	$0 5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28 84)	-2.10%
6	Nov 03 - Apr 04	23.0%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3 25%	$0 8759	$0.8352	$ 1,798 38	$ 1,740.30	$ 58.08	3 34%
7	Nov 04 - Apr 05	29.6%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189 55	$ (46.60)	-3 92%	$0 9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3 51%
8	Nov 05 - Apr 06	29.8%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10 90%	$1 3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214 89	9.61%
9	Nov 06 - Apr 07	15.1%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415 80	$ 93.99	6.64%	$1 2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	15.8%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 27.69	1 97%	$1 2044	$1.1725	$ 2,232 39	$ 2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15.2%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$ 1,555.31	$ 1,373 85	$ 181.46	13 21%	$1 2836	$1.0958	$ 2,467.49	$ 2,199.54	$ 267 95	12.18%
12	Nov 09 - Apr 10	11.4%	$0.0200	8,405,413	$ 168,108	$0.9863	$0.9416	$ 1,250.80	$ 1,209.12	$ 41.69	3.45%	$0 9865	$0.9408	$ 1,984 29	$ 1,919.03	$ 65 26	3.40%
13	Nov 10 - Apr 11	12.6%	$0.0200	10,379,804	$ 207,596	$0.8420	$0.8029	$ 1,175.03	$ 1,138 58	$ 36.45	3 20%	$0 8434	$0.8030	$ 1,880 96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	11.9%	$0.0200	7,835,197	$ 156,704	$0.8126	$0.7309	$ 1,165.61	$ 1,089.44	$ 76.17	6 99%	$0 8129	$0.7327	$ 1,845 28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	10.9%	$0.0200	8,179,524	$ 163,590	$0.6919	$0.7680	$ 743.03	$ 792.48	$ (49.45)	-6 24%	$0.6936	$0.7724	$ 1,989 86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	10.5%	$0.0200	8,930,779	$ 178,616	$0.9095	$1.1011	$ 857.72	$ 981 21	$ (123.49)	-12 59%	$0 9108	$1.1057	$ 2,736 57	$ 3,117.48	$ (380 92)	-12 22%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.7321	$ 1,127.66	$ 948.07	$ 179.59	18 94%	$0.6312	$0.7403	$ 2,422.09	$ 2,635.27	$ (213.18)	-8.09%
18	Nov 15 - Apr 16	15.3%	$0.0200	4,941,157	$ 98,823	$0.7716	$0.7516	$ 869.15	$ 712.73	$ 156.42	21 95%						
19	Nov 16 - Apr 17	11.5%	$0.0106	5,419,967	$ 57,452	$0.7268	$0.7162	$ 827.14	$ 812 38	$ 14.76	1 82%						
20	Nov 17 - Apr 18	10.6%	$0.0200	5,298,900	$ 105,978	$0.6645	$0.6445	$ 878.70	$ 865 94	$ 12.76	1.47%						
21	Nov 18 - Apr 19					$0.7611	$0.7411	$ 984.83	$ 972.12	$ 12.71	1 31%						
22	Total									$ 734.45						$ 274.09	

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

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

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

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

Company Allowance Calculation

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

Lost and Unaccounted For Gas ("LAUF") Calculation

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

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

Fuel Inventory Revenue Requirement

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

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 18-137

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

2018/2019 Winter/Summer Cost of Gas Filing

Order Approving Cost of Gas Rates and Other Charges

O R D E R   N O. 26,188

November 1, 2018

APPEARANCES: Michael J. Sheehan, Esq., for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities; the Office of the Consumer Advocate by D. Maurice Kreis, Esq., on behalf of residential ratepayers; Lynn Fabrizio, Esq., for the Staff of the Public Utilities Commission.

In this order, the Commission approves Liberty's proposed 2018/2019 winter and summer cost of gas rates. For residential customers, the initial rate for the winter period (November 1, 2018, through April 30, 2019) will be $0.7411 per therm and the fixed-price option rate will be $0.7611 per therm. The local delivery adjustment charge rate for residential customers will be $0.0660 per therm from November 1, 2018, through October 31, 2019. The initial cost of gas rate for residential customers during the summer period (May 1through October 31, 2019) will be $0.4445 per therm. For the six months beginning November 1, a typical residential customer will see an average monthly bill of about $159 compared to $151 for last winter, and for the six months beginning May 1, 2019, an average monthly bill of $40 compared to $39 in summer 2018.

I. PROCEDURAL HISTORY

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty or the Company) is a public utility that distributes natural gas to approximately 90,000 customers in southern and central New Hampshire and in the City of Berlin. On September 4, 2018, Liberty submitted a tariff filing for the 2018/2019 winter and summer periods that proposed adjustments to its cost of gas (COG) rates. The filing, which included direct testimony and supporting schedules, proposed changes to COG rates for firm sales customers, fixed winter COG rates under the fixed-price option (FPO), firm transportation COG rates, and local delivery adjustment charge (LDAC) rates.

On September 11, 2018, the Office of the Consumer Advocate (the OCA) notified the Commission of its participation on behalf of residential ratepayers pursuant to RSA 363:28. The Commission issued an Order of Notice on September 12, 2018. Commission Staff and the OCA conducted discovery and held a technical session with Liberty on October 8. There were no intervenors.

The Company filed a technical statement on October 5, 2018, followed by an amended technical statement on October 9, informing the Commission that "the low income portion of the energy efficiency budget was included in the residential program budget and was also included as an allocation between both residential and commercial & industrial (C&I) LDAC rates." Hearing Exhibit (Exh.) 3 at 1. The Company further stated that although the company has "followed the same process since the winter of 2014/2015, residential customers were only impacted during the winter of 2014/2015 due to the running balance of the over/under collection. Post winter 2014/2015 the additional low income costs included in the residential EE rate were substantially offset by the prior year over-collection." *Id.* Liberty noted the over-collected balance totaled $1,310,342, which was ultimately reflected within the overall LDAC rates rather than the COG rates. In its amended technical statement, Liberty proposed to use this overcollection to reduce the residential LDAC rate by \$0.0163 per therm to a new proposed rate of \$0.0673 per therm.

On October 30, the Company moved to reopen the record in order to update Exhibits 4, 6, 8, and 9. The Commission admitted the updated exhibits by Secretarial Letter on October 31. The updated exhibits correct an error in the RLIAP rate calculation. The correction reduced the proposed residential LDAC rate further to \$0.0660 per therm, and lowered the C&I LDAC rate from \$0.0772 per therm to \$0.0757 per therm.

Liberty's filing and subsequent docket entries, other than any information for which confidential treatment is requested of or granted by the Commission, are posted on the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2018/18-137.html.

II. COST OF GAS ADJUSTMENT MECHANISM

The COG adjustment mechanism was implemented in 1974 during a time of rapidly changing prices as a way to pass on to consumers increases and decreases in energy supply costs quickly, without having to go through extended proceedings to change delivery rates. Supply costs make up approximately half of a residential heating customer's annual bill and include commodity prices (the cost of gas), the cost to transport the gas over the pipelines, and storage costs. Liberty has little control over the price of natural gas, which is an unregulated commodity. Similarly, it has little price control over pipeline transportation rates, which are set by the Federal Energy Regulatory Commission. The COG adjustment mechanism allows the Company to pass fuel supply costs on to its customers directly and efficiently without mark-up or profit. COG rates are initially set using projected costs and sales for the upcoming winter and summer periods. Through the COG adjustment mechanism, the Company may adjust its COG rates monthly to take into account changes in the natural gas market based on actual costs to date and projected costs for the remainder of the period.

In COG proceedings, the Commission also sets the LDAC rates that allow for recovery of expenses the Commission has approved in prior dockets through a per therm surcharge to be determined and implemented in the COG proceeding. In this proceeding, those expenses include costs associated with Liberty's low-income and energy efficiency programs, an environmental surcharge for manufactured gas plant remediation, and the energy efficiency resource standard lost revenue adjustment mechanism (LRAM). The LRAM is included in the LDAC in accordance with *Energy Efficiency Resource Standard*, Order No. 25,932 (August 2, 2016), which approved the implementation of a mechanism to recover lost revenue due to the installation of energy efficiency measures.

III. POSITIONS OF THE PARTIES AND STAFF

A. Liberty

In its initial filing of September 4, Liberty proposed several rates for approval, including: winter and summer COG rates for various rate classes; annual LDAC rates for various rate classes; a fixed price option (FPO) COG rate for residential customers; and a firm transportation COG rate. Exh. 1 at 47-49, 52.

At the October 22 hearing, Liberty entered several updated exhibits primarily affecting the LDAC. The first was an updated calculation of the Rate Case Expense & Recoupment Rate (Recoupment Rate) portion of the LDAC. Exh. 5. The updated calculation indicated that the Company believes the new Recoupment Rate should decrease from the filed rate of $0.0105 per therm (Exh. 1 at 54) to the new rate of $0.0079 per therm. Liberty also entered, as Exhibit 6, an updated calculation for the Residential Low Income Assistance Program (RLIAP). The calculation added a "test year adjustment to Base Rates" of $1,820,418 to the recovery amount but did not reduce the "First Block" or "Last Block" R-3 Delivery Charge which decreased from the filed amount of $0.5631 to the updated amount of $0.5502. Exh. 7 and Updated Exh. 8.[1] The Company included an updated Energy Efficiency Charge (EEC) of $0.0287 (Updated Exh. 4) down from the filed EEC of $0.0450 for residential customers,[2] but included no further information concerning the decrease. On October 30, 2018, Liberty filed an Updated Exh. 6, which corrected the RLIAP rate calculation, along with revised schedules affected by the correction. (Updated Exh. 4, 8, and 9).

As revised, Liberty's proposed winter COG per therm rates for the various rate classes are: $0.7411 for residential, with $0.7611 for the fixed price option; $0.7403 for commercial and industrial (C&I) high winter use; and $0.7456 for C&I low winter use. Updated Exh. 8. Liberty proposed initial summer COG per therm rates of $0.4445 for residential, $0.4417 for C&I high winter use, and $0.4506 for C&I low winter use customers. *Id*. The Company also proposed an LDAC rate of $0.0660 per therm for residential customers from November 1, 2018, through October 31, 2019, and $0.0757 per therm for C&I customers for the same period. *Id*.

The following tables include the expected total bill impact based on the prior winter's and summer's average use of each customer class. Updated Exh. 9.

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[1] The updated RLIAP rate calculation for the R-3 first block base rate (Exhibit 6, lines 2 and 10) is $0.5631 per therm, whereas the R-3 first block base rate approved in DG 17-048 and in Updated Exhibit 8 (Residential Heating – R-3) is $0.5502 per therm. Correcting the error reduces the $2.4 million program costs by $50,000; that correction will be included in the RLIAP reconciliation and reflected in next year's RLIAP rate.

[2] By approving the reduced EE component of the LDAC, the Commission is making no judgment on issues raised in the 2018-2020 New Hampshire Statewide Energy Efficiency Plan Update, filed September 14, 2018, in Docket No. DE 17-136.

Winter 2018-2019 Projected Bill Impacts

Class	2017/2018 (Actual)	2018/2019 (Projected)	Percent Change
R-3 Residential Heating	$ 905	$ 953	5%
G-42 C&I High Winter Use	$17,859	$18,438	3%
G-52 C&I Low Winter Use	$12,250	$12,594	3%

Summer 2019 Projected Bill Impacts

Class	2018 (Actual)	2019 (Projected)	Percent Change
R-3 Residential Heating	$ 232	$ 241	4%
G-42 C&I High Winter Use	$3,324	$3,642	10%
G-52 C&I Low Winter Use	$5,119	$5,605	10%

A typical residential heating customer will see an average monthly bill of about $159 per month in winter 2018/2019 compared to $151 for winter 2017/2018, and an average monthly bill of $40 in the 2019 summer period compared to $39 in the 2018 summer period. *Id.*

The Company also proposed: (1) a supplier balancing charge of $0.19 per MMBtu of daily imbalances; (2) a transportation peaking service demand charge of $20.41 per MMBtu of peak maximum daily quantity; (3) a gas allowance factor of 1.8 percent; (4) a transportation capacity allocator; (5) short-term debt limits of $19,222,230 for fuel financing, and $94,878,262 for non-fuel financing for the November 1, 2018, through October 31, 2019 period.

B. Staff

At the hearing, Staff expressed support for approval of the 2018/2019 COG and LDAC rates as amended by the technical statement filed on October 9 and as revised by the exhibits presented at the October 22 hearing.

C. OCA

The OCA stated that the proposed rate changes reflected in the Company's filing and technical statement are just and reasonable, and recommended that those changes be approved. The OCA also noted that any effort on the Company's part to make its tariffs clearer and more comprehensible would be helpful.

IV. COMMISSION ANALYSIS

The Commission has broad statutory authority to set rates in addition to "powers inherent within its broad grant" of express authority. *See Appeal of Verizon New England, Inc.*, 153 N.H. 50, 64-65 (2005) (citations omitted). The Commission applies the "just and reasonable" ratemaking standard of RSA 374:2 and RSA 378:7 when setting COG rates. Based on our review of the record in this docket, we approve the proposed, revised 2018/2019 winter and 2019 summer COG rates presented in Updated Exhibits 4 and 9 as just and reasonable. We also approve Liberty's LDAC rates as presented in Updated Exhibit 4. Since actual costs and revenues are reconciled every year, any adjustments needed as a result of further inquiry into the matters addressed in this order, including the correction to the RLIAP calculation, can be made in Liberty's COG filing for 2019/2020.

Pursuant to *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 24,963 (April 30, 2009), the approved non-FPO rates may be adjusted downward so far as needed and upward by no more than 25 percent, without further Commission action. *See also Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 25,958 (October 26, 2016). By approving the corrected rates in Updated Exhibit 9 at the beginning of the period, the 25 percent upward limit has an appropriate starting point.

Based upon the foregoing, it is hereby

ORDERED, that Liberty's 2018/2019 winter period COG per therm rates effective for service rendered on or after November 1, 2018, and Liberty's 2019 summer season per therm rates effective May 1, 2019, are approved as set forth in this Order, as follows:

Customer Class	2018-2019 Winter COG	2018-2019 Winter Maximum COG	2018-2019 Winter FPO	2019 Summer COG	2019 Summer Maximum COG
Residential	$0.7411	$0.9264	$0.7611	$0.4445	$0.5556
C&I High Winter Use	$0.7403	$0.9254		$0.4417	$0.5521
C&I Low Winter Use	$0.7456	$0.9320		$0.4506	$0.5633

and it is

FURTHER ORDERED, that Liberty may, without further Commission action, adjust the COG rates based on the projected over- or under-collection for the period, the adjusted rate to be effective the first day of the month and not to exceed, cumulatively, a maximum rate of 25 percent above the approved rate with no limitation on reductions to the COG rates; and it is

FURTHER ORDERED, that Liberty shall provide the Commission with its monthly calculation of the projected over- or under-collection, along with the resulting revised COG rates for the subsequent month, not less than five business days prior to the first day of the subsequent month. Liberty shall include revised Calculation of the Firm Sales Cost of Gas Rate tariff pages and revised rate schedules under separate cover letter if Liberty elects to adjust COG rates, with revised tariff pages to be filed as required by N.H. Code Admin. Rules Puc 1603; and it is

FURTHER ORDERED, that the over- or under-collection shall accrue interest at the prime rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates, the rate to be adjusted monthly; and it is

FURTHER ORDERED, that Liberty's proposed LDAC per therm rates for the period November 1, 2018, through October 31, 2019, effective for service rendered on or after November 1, 2018, are $0.0660 and $0.0757 for residential and C&I customers, respectively; and it is

FURTHER ORDERED, that Liberty's proposed firm transportation winter COG rate of $0.0005 per therm for the period November 1, 2018, through April 30, 2019, is approved; and it is

FURTHER ORDERED, that Liberty's proposed supplier balancing charge of $0.19 per MMBtu of daily imbalance volumes is approved; and it is

FURTHER ORDERED, that Liberty's proposed transportation peaking service demand charge of $20.41 per MMBtu of peak maximum daily quantity is approved; and it is

FURTHER ORDERED, that Liberty's company gas allowance factor of 1.8 percent is approved; and it is

FURTHER ORDERED, that Liberty's proposed transportation capacity allocators as filed in proposed First Revised Page 148, Superseding Original Page 148 are approved; and it is

FURTHER ORDERED, that Liberty's proposed short-term debt limits of $19,222,230 for fuel financing and $94,878,262 for non-fuel financing for the period November 1, 2018, through October 31, 2019, are approved; and it is

FURTHER ORDERED, that Liberty shall promptly file properly annotated tariff pages in compliance with this order no later than 15 days from the issuance date of this order, as required by N.H. Code Admin. Rules Puc 1603; and it is

FURTHER ORDERED, that Liberty shall file its proposed notice of rate change to customers with the Director of the Consumer Services and External Affairs Division, prior to delivery to its customers.

By order of the Public Utilities Commission of New Hampshire this first day of November, 2018.

Martin P. Honigberg Chairman	Kathryn M. Bailey Commissioner	Michael S. Giaimo Commissioner

Attested by:

Debra A. Howland
Executive Director

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

Executive.Director@puc.nh.gov
al-azad.iqbal@puc.nh.gov
amanda.noonan@puc.nh.gov
anthony.leone@puc.nh.gov
catherine.mcnamara@libertyutilities.com
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steven.mullen@libertyutilities.com

Docket #: 18-137-1 Printed: November 01, 2018

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

Liberty Utilities

EXHIBIT
tabbies
#12
DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIRECT TESTIMONY

OF

DAVID B. SIMEK

April 28, 2017

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed and your position?

A. I am a Lead Utility Analyst for Liberty Utilities Service Corp. ("Liberty") which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company"). I am responsible for providing rate-related services for the Company.

Q. Please describe your educational background and training.

A. My educational background and qualifications are set forth in the prefiled joint testimony filed with Daniel S. Dane in support of EnergyNorth's request for a permanent increase on distribution rates.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's changes to its tariff as a result of this distribution rate case filing.

Q. Please describe the changes that were made.

A. Attachment DBS-TARIFF-1 contains a clean version of the proposed tariff while Attachment DBS-TARIFF-2 contains a redlined version. The following substantive changes were made to the tariff:

- the distribution rates were modified to incorporate the proposed rates contained in Attachment RATES-7 of the Simek-Therrien rate design testimony;
- the Towns of Pelham and Windham and the City of Keene were added to the Service Area of the tariff;
- a Revenue Decoupling Mechanism was added; and
- the Lost Revenue Adjustment Mechanism (LRAM) was deleted.

The last change is being made because upon implementation of the Revenue Decoupling Mechanism, there will no longer be a need for a LRAM, since the decoupling mechanism will account for changes in sales volume due to energy efficiency measures.

The Company has also made housekeeping changes to the tariff which include correcting spelling and grammatical errors, page re-numbering and formatting, header and footer formatting, and margin corrections.

Q. Have all changes made to the EnergyNorth tariff been redlined in Attachment DBS-TARIFF-2?

A. No, only substantive changes were redlined. In order to facilitate review, the housekeeping changes mentioned above were not redlined, because redlining such changes would produce a document that would have so many changes on each page, it would be unwieldy.

Q. Has the Company added the Keene Division to the EnergyNorth tariff?

A. Yes, the Keene Division has been added to the EnergyNorth tariff. All EnergyNorth distribution rates and charges including those contained in the local distribution adjustment clause (LDAC) will now be applicable to Keene customers. The Company is proposing that a separately calculated cost of gas rate continue to apply to Keene customers. Therefore, we have included a cost of gas provision for Keene customers in the tariff.

Q. Will Keene commercial customers still have the Fixed Priced Option to choose as their Winter Cost of Gas rate?

A. Yes. The Company is not proposing to change any part of Keene's current cost of gas procedures.

Q. What will happen to the existing Keene tariff?

A. The existing Keene tariff will no longer be valid once permanent rates become effective following a Commission order in this docket.

Q. Under the Delivery Terms and Conditions section of the EnergyNorth tariff is a section for a Supplier Service Agreement. Is a copy of the Agreement provided in the tariff?

A. Yes. A copy of the Supplier Service Agreement is included with this filing to rectify the current condition that although the current tariff includes references to the Supplier Service Agreement, a copy of that agreement was not previously included.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 15-137

GAS AND ELECTRIC UTILITIES

Energy Efficiency Resource Standard

Order Approving Settlement Agreement

O R D E R N O. 25,932

August 2, 2016

APPEARANCES: Matthew J. Fossum, Esq., for Public Service Company of New Hampshire d/b/a Eversource Energy; Susan S. Geiger, Esq., of Orr & Reno, P.A., for Northern Utilities, Inc., and Unitil Energy Systems, Inc.; Michael J. Sheehan, Esq., for Liberty Utilities Corp. (Granite State Electric) d/b/a Liberty Utilities, Inc., and for Liberty Utilities Corp. (EnergyNorth Natural Gas) d/b/a Liberty Utilities; Mark W. Dean, Esq., for New Hampshire Electric Cooperative; Dennis Labbe, Esq., of the New Hampshire Legal Assistance, for The Way Home; Ryan Clouthier for the New Hampshire Community Action Agencies' Southern New Hampshire Services, Inc., and the Belknap-Merrimack Counties, Inc.; Melissa Birchard, Esq., for Conservation Law Foundation NH; Laura Richardson for The Jordan Institute; Kate Epsen for the NH Sustainable Energy Association; Joseph Harrison for the Community Development Finance Association; Ellen Hawes for the Acadia Center; Tom Rooney for TRC Energy Services; Rep. Robert Backus, *pro se*; Meredith A. Hatfield, Esq., for the New Hampshire Office of Energy and Planning; Rebecca Ohler for the New Hampshire Department of Environmental Services; Donald M. Kreis, Esq., of the Office of the Consumer Advocate, on behalf of residential ratepayers; and Rorie E. Patterson, Esq., for Staff of the New Hampshire Public Utilities Commission.

In this order, the Commission approves a Settlement Agreement supported by all parties, extending the 2014-2016 Core program an additional year (through 2017) and establishing an Energy Efficiency Resource Standard (EERS). The EERS is a framework within which the Commission's energy efficiency programs shall be implemented, and the effective date for implementation is January 1, 2018. The framework consists of three-year planning periods and savings goals as well as a long-term goal of achieving all cost-effective energy efficiency. The electric and gas utilities will be administrators of the EERS programs to achieve specific statewide savings goals for the 2017 Core program and for the first three-year period of the EERS. Specific programs will be subject to Commission approval and such approval will require a demonstration that they are cost effective in subsequent proceedings before the Commission. This order also establishes a recovery mechanism to compensate the utilities for lost-revenue related to the EERS programs, and approves the performance incentives and the processes described in the Settlement Agreement for stakeholder involvement, evaluation, measurement and verification, and our oversight of the EERS programs.

I. BACKGROUND

On May 8, 2015, the Commission opened this proceeding to establish an Energy Efficiency Resource Standard. An EERS is a policy that sets specific targets or goals for energy savings, which utility companies serving New Hampshire ratepayers must meet. The Commission indicated that the EERS would include long- and short-term, energy-type-specific savings goals based on sales volumes for 2014. In addition, the Commission defined the scope of the proceeding to include consideration of funding requirements, program-cost recovery, lost-revenue recovery, performance-based incentives, program administration, evaluation, measurement, and verification (EM&V), and ways to transition from the existing energy efficiency paradigm to the EERS. The Order of Notice and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted on the Commission's website at: http://puc.nh.gov/Regulatory/Docketbk/2015/15-137.html.

Until now, the Commission has implemented energy efficiency primarily through the Core programs, which has evolved in the last 15 years into a statewide system used by electric and natural gas utilities to deliver energy efficiency products and services to their customers or members.[1] Since 2001, the Systems Benefits Charge funding for Commission-regulated energy efficiency has remained at $0.0018 per kWh level. The programs have been designed to deliver as much energy efficiency savings as possible within the bounds of that funding, plus additional funding in recent years from the Regional Greenhouse Gas Initiative (RGGI) and the Independent System Operator-New England's (ISO-NE) Forward Capacity Market (FCM). Establishing an EERS presents an opportunity to set savings goals based on savings potential in addition to consideration of the funding level.

Several New Hampshire specific studies of energy efficiency potential have been conducted in the last decade, and all suggested that additional opportunities for cost-effective energy efficiency exist beyond those attained through the Core program.[2] In September 2014, the Governor's Office of Energy and Planning released a 10-year State Energy Strategy, which recognized the need for an EERS:

> In order to reduce energy costs by implementing more cost-effective efficiency programs, the State must set specific efficiency goals and metrics to measure progress. The Public Utilities Commission should open a proceeding that directs the utilities, in collaboration with other interested parties, to develop efficiency savings goals based on the efficiency potential of the State, aimed at achieving all cost effective efficiency over a reasonable time frame.

2014 New Hampshire State Energy Strategy, Executive Summary at ii.

On February 3, 2015, Commission Staff filed a report entitled "Energy Efficiency Resource Standard: A Straw Proposal for New Hampshire." Staff's report concluded a

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[1] All of the New Hampshire electric and gas utilities except the New Hampshire Electric Cooperative (NHEC) have customers. NHEC supplies electricity to its members. Subsequent references herein to customers shall include NHEC members unless otherwise stated.
[2] *Additional Opportunities for Energy Efficiency in New Hampshire, Final Report* (January 2009), prepared for the Commission by GDS Associates Inc. (GDS), RLW Analytics, and Research Into Action; *Independent Study of Energy Policy Issues* (2011), prepared for the Commission by Vermont Energy Investment Corporation (VEIC); and *Increasing Energy Efficiency in New Hampshire: Realizing Our Potential* (November 2013), prepared by VEIC, GDS, and Jeffrey H. Taylor & Associates.

months-long endeavor to solicit and capture feedback on establishing an EERS. Staff's report included information about other jurisdictions, input from New Hampshire efficiency stakeholders, questions for additional consideration, and a series of preliminary recommendations.

On March 13, 2015, the Commission opened an investigative docket, IR 15-072, to receive written comments on several threshold recommendations within Staff's report. Written comments were submitted by numerous stakeholders including all of the electric and gas utilities (Joint Utilities),[3] the Office of the Consumer Advocate (OCA), the Governor's Office of Energy and Planning (OEP), and the Department of Environmental Services (DES). The comments reflected unanimous support for the Commission's establishment of an EERS at that time, under existing statutory authority, to advance a policy of energy efficiency as a least-cost supply resource for customers of the Joint Utilities. Some support for an EERS, however, was qualified by requests to consider the universe of EERS issues, and to engage expert assistance at the time of its development. Based on those comments and the recommendations contained in Staff's Straw Proposal report, the Commission opened this proceeding to establish an EERS and to examine the issues related to a successful launch of this important and timely policy.

II. PROCEDURAL HISTORY

The Commission named the Joint Utilities as mandatory parties, and received appearances from each. In addition, the OCA notified the Commission of its participation by statutory right on behalf of residential ratepayers. RSA 363:28, II.

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[3] Liberty Utilities Corp. (Granite State Electric) d/b/a Liberty Utilities (Liberty) and Liberty Utilities Corp. (EnergyNorth Natural Gas) d/b/a Liberty Utilities (jointly, Liberty); Unitil Energy Systems, Inc., and Northern Utilities, Inc. (jointly, UES); Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource); and NHEC. Although the order refers to NHEC as one of the Joint Utilities, we recognize that our jurisdiction over NHEC is limited by law. RSA 362:2.

Petitions to intervene were filed by DES; OEP; Conservation Law Foundation (CLF); New Hampshire Community Action Agencies' Southern New Hampshire Services, Inc., and Belknap-Merrimack Counties, Inc.(CAA); The Jordan Institute (Jordan); The Way Home (TWH); New Hampshire Sustainable Energy Association (NHSEA); the New Hampshire Community Development Finance Authority (CDFA); the New England Clean Energy Council (NECEC); TRC Energy Services (TRC); the Acadia Center (Acadia); Representative Robert A. Backus, *pro se*; Henry Herndon, *pro se*; and MCR Performance Solutions, LLC (MCR). The Commission denied Mr. Herndon's and MCR's intervention since neither party has any "rights, duties, privileges, immunities or other substantial interests that may be affected by the proceeding," and both could participate without being made a party since they have access to docketed materials on the Commission's website and may make comments at hearing or in writing pursuant to N.H. Code of Admin. Rules Puc 202.06.

The Commission held a prehearing conference on June 3, 2015, and, afterwards, the parties met in a technical session to develop a proposed procedural schedule and determine other procedural requirements for managing the docket. On June 10, 2015, Staff filed a report of the technical session and a request, on behalf of the parties, for additional time to develop the procedural schedule, which the Commission approved. The Parties and Staff met again on June 29, 2015, to develop a procedural schedule, which included multiple technical sessions each focused on a specific topic or issue identified by the Commission in its Order. The well-attended technical sessions featured presentations from the Joint Utilities as well as New England regional experts. The presentations included information about how other New England states have structured and administered their EERS programs and the Joint Utilities' experience with those programs.

Following the technical sessions, NHSEA along with CLF, Jordan, and NECEC (collectively, the Sustainable Energy Group)[4], Staff, and the Joint Utilities filed EERS proposals supported by testimony. Also, TRC and Acadia filed comments at that time. After those filings, a period of discovery occurred, and responsive testimony was filed by the OCA, the Sustainable Energy Group, and the Joint Utilities. Also, the Acadia Center and TWH filed reply comments.

Settlement negotiations followed, and, on April 27, 2016, a Settlement Agreement was filed by Staff on behalf of all parties except Rep. Backus. A hearing on the Settlement Agreement took place on May 2, 2016. At that hearing, the Settling Parties spoke strongly in favor of approving the agreement, and Rep. Backus supported those positions.

III. ORIGINAL AND SETTLEMENT POSITIONS OF THE PARTIES

The full EERS proposals and comments covered topics studied by the parties in the technical sessions as well as others, including: program administration; savings targets; funding; cost recovery; recovery of lost revenue; performance incentives; stakeholder involvement; evaluation, measurement and verification (EM&V); regulatory process; and implementation date. The parties included energy efficiency stakeholders who have participated for years in the Commission's programs and represented a broad spectrum of interests. The filings unanimously supported the creation of an EERS and featured many commonalities. Differences between the parties' original positions related primarily to the recommended savings targets, lost-revenue recovery, and the implementation date. The Settlement Agreement resolved all issues as described below.

[4] The Nature Conservancy join in this filing but was not a party to this proceeding.

A. Guiding Principles

1. Staff

Staff described several principles that should guide the EERS development. According to Staff, the EERS should build on the Commission's existing energy efficiency policy and experience with the Core programs. The EERS should respond to the recommendations in the 10-year State Energy Strategy and should be consistent with State law and industry best practices. Also, the EERS should include challenging but achievable statewide savings targets that are consistent with targets in other jurisdictions and the targets suggested in New Hampshire specific studies.

2. Joint Utilities

The guiding principles recommended by the Joint Utilities included establishing savings targets with a long-term goal of all achievable cost-effective energy efficiency within the context of available, sustainable funding; using at least a three-year, short-term planning period; considering rate impacts on customers in setting short-term goals; focusing primarily on comprehensive electric and gas programs with secondary focus on fuel neutral programs; continuing joint coordination of programs by the electric and gas utilities; driving innovation in technology, outreach, and regulation to accelerate energy efficiency gains; leveraging the private financing market; and increasing public awareness of the benefits of energy efficiency. According to the Joint Utilities, those guiding principles are consistent with the Commission's existing energy efficiency policy, which supports the award-winning, innovative, Core programs that have had a significant, positive impact on utility customers across the state. The Joint Utilities' support the creation of an EERS, because they believe an EERS will also provide significant benefits for New Hampshire utility customers.

3. The Way Home

TWH supported the guiding principle espoused by the Joint Utilities that energy efficiency programs be available to all customers, including low-income residential customers. TWH defined low income as at or below 200 percent of the federal poverty guidelines.[5] According to TWH, approximately 20 percent of New Hampshire residents are considered low income by this standard.

B. Program Administration

1. Staff

Staff discussed the use of independent third-party administrators in other jurisdictions and noted the benefits of such a structure. Staff observed, however, that the Joint Utilities have effectively administered the Core programs. Consequently, Staff recommended that the Joint Utilities administer the EERS programs at this time.

2. Joint Utilities

The Joint Utilities recommend that they administer the EERS programs based on their years of successful experience as administrator of the Core programs and their commitment to energy efficiency's success. According to the Joint Utilities, they have the knowledge, infrastructure, and relationships in place to scale up and transition the Core programs quickly to EERS programs. In support, the Joint Utilities noted their deep understanding of customer usage, their established and widespread vendor networks, their access to expertise from other jurisdictions, and the findings of several studies that customers consider utilities as trusted advisors on energy efficiency. The Joint Utilities also provided recent examples of their ability to scale up Core programs quickly and effectively beyond planned program budgets.

[5] For a household of one, 200 percent of the federal poverty guidelines is $23,450 in annual income. For a household of two, low-income eligibility is capped at a total household annual income of $31,860.

3. Sustainable Energy Group

The Sustainable Energy Group opined that the Joint Utilities are capable of serving as administrator of the EERS programs. Nonetheless, the Sustainable Energy Group recommended that the Commission consider the benefits of transitioning over time some or all of program delivery to a non-utility statewide program administrator. Competitively bidding out the entire portfolio or individual pieces of the EERS may maximize private funding and deliver savings in a manner that allows for all potential administrators, utilities, and third parties alike, to offer comprehensive, least-cost savings. According to the Sustainable Energy Group, important conditions for successful administration include the right incentives, oversight, underlying procurement and resource acquisition policies, clarity of the purpose for pursuing efficiency, consistency of policy over time, and consensus among stakeholders.

4. TRC

TRC recommended programs that leverage consumer engagement efforts from multiple sources including the Joint Utilities and third-party administrators.

5. The Way Home

TWH supported the Joint Utilities' administration of EERS programs, at least in the short term. According to TWH, with appropriate performance incentives, rate structures, and program oversight in place, the Joint Utilities should have the incentive and initiative to continue implementing robust energy efficiency programs effectively, to the mutual benefit of ratepayers, shareholders, and the natural environment of the state.

6. Settlement Agreement

The Settlement Agreement provides for the Joint Utilities' administration of the EERS programs, at least for the first three years. In addition, the Settling Parties recommend that no changes to the Joint Utilities' administrative role may be proposed prior to January 1, 2020, or be effective prior to January 1, 2021.

C. Savings Targets and Planning Periods

1. Staff

Staff proposed two sets of statewide, three-year, short-term savings targets and ten-year, "notional" long-term targets, referred to as Plan A and Plan B. Staff's targets, as well as all other parties' target recommendations, were expressed as a percent of actual 2014 kilowatt-hour (kWh) or one million British thermal units (MMBtu) sales. Staff noted that its annual year-over-year targets for gas savings were lower than its annual year-over-year electric savings targets, because the gas utilities have reached a higher level of savings historically relative to 2014 actual MMBtu usage.

Staff's Plan A sets the initial short-term cumulative targets at 1.82 percent for electric savings and 2.14 percent for gas savings over a three-year period. Both of the Plan A short-term targets are higher than current Core savings targets but lower than Plan B levels. Plan B's initial three-year cumulative targets are 2.04 percent for electric and 2.39 percent for gas. Staff estimated that using Plan B's short-term savings targets would result in cumulative kWh savings of approximately 220 million kWh by the end of the first three-year period, and lifetime kWh savings of approximately 3.1 billion kWh.[6] Staff's ten-year long-term targets for Plan A were 9.74 percent for electric and 10.20 percent for gas. Staff's long-term targets for Plan B were 14.48 percent for electric and 13.96 percent for gas. Staff referred to its long-term target as a "guidepost" and recommended that it be refined during the first three-year period of the EERS.

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[6] Based on average life of 14.3 years – *i.e.*, cumulative kWh savings of 220 million kWh x 14.3 years average life = lifetime kWh savings of 3.146 billion kWh.

Staff asserted that both Plan A and Plan B targets are consistent with the Commission's energy efficiency policies; the State's 10-Year Energy Strategy; RSA 378:37, as well as a recent change in the Least Cost Integrated Resource Planning (IRP) law; and RSA 378:38, which requires utilities to maximize the use of cost-effective energy efficiency. Staff also stated that it developed its proposed savings targets to meet the criteria for an EERS as established by the American Council for an Energy-Efficient Economy (ACEEE), including creating a framework that promotes market stability. Further, according to Staff, its savings target recommendations are comparable to savings targets in other New England states and numerous Midwestern states, as well as to the potential savings identified in New Hampshire specific studies conducted during the last decade. Describing them as reasonable and achievable, Staff recommended the Commission's adoption of Plan B savings targets.

2. Joint Utilities

Similar to Staff, the Joint Utilities recommended a framework that includes short-term planning periods of at least three years. According to the Joint Utilities, transitioning from the Core's two-year planning period to a three-year planning period will provide more stability and continuity in program delivery, which will assist customers and other stakeholders in planning and investment decisions. The Joint Utilities contended that three-year periods would allow flexibility to adjust specific savings targets in response to changes in market conditions and to New Hampshire specific information such as results from evaluation and technical potential studies. A three-year planning period is also consistent with the EERS planning periods used in neighboring states and with the ACEEE's definition of an EERS.

Under the Joint Utilities' framework, the Commission would set annual kWh and MMBtu sales reduction targets, customized for each utility to account for different market conditions and opportunities in different service territories and for different classes of customers. The Joint Utilities cautioned against setting targets based solely on aligning New Hampshire with neighboring jurisdictions. According to the Joint Utilities, savings targets should come from demonstrated savings potential in New Hampshire, although little weight should be given to prior studies, which are outdated at this point. The Joint Utilities recommended that savings goals should only apply to regulated fuels, but savings related to unregulated fuels should be identified and tracked so that associated benefits are captured and reported. The costs to achieve the savings targets should be fully funded and, in setting the targets, the Commission should be mindful of the impacts of such funding on customers. Citing the ACEEE, the Joint Utilities argued that the EERS long-term goal should be all achievable cost-effective energy efficiency.

3. Sustainable Energy Group

The Sustainable Energy Group recommended setting explicit quantitative short-term goals, preferably expressed as a cumulative goal over a three-year term as well as measured reductions in peak demand. Short-term targets, stated the Sustainable Energy Group, allow for greater flexibility and consideration of emerging and changing technology. Specifically, the Sustainable Energy Group recommended as reasonable and achievable, cumulative short-term goals of 3.1 percent for electric savings and 2.25 percent for gas energy savings for the 2017-2019 period.[7] The Sustainable Energy Group also recommended nominal interim annual targets of 0.8 percent, 1.0 percent, and 1.3 percent for electric savings and 0.7 percent, 0.75 percent, and

[7] The Sustainable Energy Group noted that their recommended targets are based on net savings (*i.e.*, not including "free rider" participants and including "spill over" participants) and do not include savings from updated codes and standards, self-direct customers, and before-the-meter projects. A "free rider" participant is one whose savings is counted in the program but who would have made the efficiency investment even in the absence of the program. A "spill over" participant is one who made efficiency investments but who did not participate in the program and was therefore not counted. Should gross or other savings be counted, the Group recommended that the Commission set even higher savings targets.

0.8 percent for gas savings. The Sustainable Energy Group described their recommended targets as well below actual achievement and near-term goals in most New England states.

According to the Sustainable Energy Group, longer-term goals may also be appropriate and are valuable, both as aspirational metrics and to express a commitment to efficiency in the future. The changing landscape of energy and efficiency, however, suggests that these may be best expressed in qualitative terms, such as all cost-effective energy efficiency. The Sustainable Energy Group opined that such a qualitative long-term goal can be quantified based on periodic revising of what is cost-effective given conditions at the time. A goal of all cost-effective energy efficiency, the Sustainable Energy Group stated, is consistent with New Hampshire's 10-year State Energy Strategy, RSA 378:37, and the Commission's objective of ensuring just and reasonable rates. In addition, to provide the confidence that businesses need to enter the efficiency market and invest for future growth, the Sustainable Energy Group recommended that long-term goals should not be used as a ceiling or an arbitrary maximum if and when greater investments in efficiency are justified. To achieve all cost-effective energy efficiency over the long term, the Sustainable Energy Group recommended mid-term annual goals of 2 percent and 1 percent, for electric and gas, respectively, by 2021.

For electric utilities, the Sustainable Energy Group also recommended a peak demand reduction target, because peak demand growth drives electricity prices by creating the need for additional generation, transmission, and distribution capacity requirements, and by driving up wholesale energy prices. According to the Sustainable Energy Group, that target should be set at a minimum of the expected peak demand reduction from a comprehensive efficiency portfolio designed to reach the electric savings target.

The Sustainable Energy Group opined that increasing energy efficiency targets can mean lower customer bills, improved customer choice, enhanced system reliability, and increased economic activity statewide. According to the Sustainable Energy Group, those objectives are consistent with New Hampshire's Electric Utility Restructuring law, RSA 374-F:3, X, prioritizing the reduction of market barriers to investments in energy efficiency, not reducing cost-effective customer conservation, and targeting cost-effective efficiency opportunities that may otherwise be lost due to market barriers. Energy efficiency resources are particularly critical, the Sustainable Energy Group argued, given the current regional landscape of retiring generation, decreased supply diversity, and the need to meet significant environmental goals. To meet increased savings goals, the Sustainable Energy Group recommended statewide delivery of some efficiency services, which can provide consistency in program offerings and brand recognition as well as economies of scale in terms of marketing, vendor management, and other administrative needs.

4. Acadia

Acadia provided information and recommendations concerning savings targets. All New England states, according to Acadia, far exceed existing New Hampshire savings goals. For example, compared to the Core electric savings goals for 2016 of 0.68 percent, Rhode Island's electric savings goal is 2.55 percent, and compared to the Core gas savings goal for 2016 of 0.62 percent, Rhode Island's gas savings goal is 1.05 percent.

Acadia recommended that savings targets be approved on three-year cycles. Specifically, Acadia recommended ramping up New Hampshire's savings goals during the first three years of the EERS to 2.5 percent cumulative electric savings and 1.25 percent cumulative gas savings.

5. TRC

TRC recommended aggressive energy savings mandates to drive increased investments in energy efficiency. TRC suggested long-term savings targets that will lead to all cost-effective energy efficiency as well as energy savings that are on par with other New England states. TRC also provided information about the energy efficiency markets in California, New York, and New Jersey, which it described as robust and mature. TRC suggested that the Commission look to those jurisdictions for best practices to launch an EERS effectively and efficiently.

6. The Way Home

TWH agreed with the Joint Utilities' recommendation to establish specific, short-term savings goals with an ultimate savings target of all achievable cost-effective energy efficiency. TWH similarly noted that such a long-term target is consistent with New Hampshire's energy policy, which recognizes efficiency as a first-priority, least-cost resource. TWH strongly recommended that energy efficiency services to low-income residential customers, such as the Core Home Energy Assistance (HEA) program, continue. According to TWH, without such services, efficiency is not available to all customers, and the goal of achieving all cost-effective energy efficiency is undermined.

TWH supported a three-year planning cycle and cumulative targets, along with annual implementation plans and annual interim nominal targets. TWH suggested that shorter-term targets should be quantified as electric kWh and gas MMBtu annual sales reductions based on demonstrated savings potential and should apply only to regulated fuels. Energy savings from unregulated fuels, according to TWH, should be counted towards quantifying the benefits of energy efficiency measures in the cost-benefit tests by which all programs are screened.

7. Settlement Agreement

The Settlement Agreement provides deadlines for the Joint Utilities' filing of a 2017 Core plan as well as the Settling Parties' expectations for that plan, including statewide savings goals of 0.60 percent for electric savings and 0.66 percent for gas savings, using 2014 delivered sales as the baseline figure. The Settlement Agreement also defines the savings targets for the first three-year period of the EERS, 2018-2020, and describes the collaborative process by which the plan for that period shall be developed within the proposed framework. The cumulative electric savings goal is 3.1 percent of delivered 2014 kWh sales, with interim annual savings goals of 0.80 percent, 1.0 percent, and 1.3 percent. The cumulative gas savings goal is 2.25 percent of delivered MMBtu 2014 sales, with interim annual savings goals of 0.70 percent, 0.75 percent, and 0.80 percent. The Settling parties agree that future goals will be determined in the planning processes related to the second and any subsequent three-year EERS periods, with the intent of attaining the goal of achieving all cost-effective energy efficiency.

D. Costs and Funding

1. Staff

Staff recommended that the utilities recover the just, reasonable, and prudent costs incurred in developing, promoting, and delivering the EERS programs. To the extent possible, Staff also recommended allocating program spending based on class-specific sales volumes, which is consistent with long-standing Commission policy.

For the first triennium, Staff recommended funding most of the utilities' cost recovery with increases to the System Benefits Charge (SBC) and the Local Distribution Adjustment Charge (LDAC). The remaining costs, according to Staff, would be covered by existing funding from RGGI and the ISO-NE FCM. Staff observed that, recently, federal funding has been available and used to support on-bill and third-party financing options for certain Core programs, but that funding is only available for a limited period of time and its future is uncertain.

To supplement public funding, Staff recommended exploring and developing private funding options, which could include loan portfolio sales and asset-backed securitization. According to Staff, private funding supplementation is necessary to achieve all cost-effective energy efficiency, but requires market growth, as well as stability and benefits from standardization of products, processes, and the availability of accurate risk and performance data.

Staff estimated the costs of Plan B for the first triennium, including the costs of lost revenues, performance incentives, several resources for an EERS advisory board, and inflation, as approximately $108 million for electric and $32 million for gas. To recover those amounts, the SBC would need to be increased from $0.0018 per kWh to rates within the range of $0.0022 to $0.0036 per kWh, and the energy efficiency portion of the LDAC would need to be increased from $0.0291 per therm to rates within the range of $0.0340 to $0.0450 per therm. Staff estimated the monthly bill impact of the SBC increase under Plan B for the first triennium on an average residential electric customer, with monthly usage of 700 kWh per month, as an increase of $0.25 to $1.27 per month. Staff estimated the monthly bill impact of Plan B on a General Service customer using 7,000 kWh per month as an increase of $2.53 to $ 12.70 per month. Staff's calculation of SBC bill impacts alone, did not attempt to estimate any of the additional customer savings resulting from the increased energy efficiency measures. Staff did not calculate monthly bill impacts of the LDAC increases associated with Plan B, because the LDAC is utility- and customer-class specific.

2. Joint Utilities

Like Staff, the Joint Utilities recommend funding the EERS with the SBC and LDAC. According to the Joint Utilities, customers are the most reliable and practical sources for funding energy efficiency programs. As the primary beneficiaries of the energy efficiency measures installed, utility customers are more likely to participate by partially funding the programs. Because the SBC and LDAC are variable rates (*i.e.*, applied on a per kWh and per therm basis) and are set according to consumption, using them to fund the EERS will impact customers according to their usage and send an enhanced price signal for using energy more efficiently, which is consistent with the goal of an EERS.

The Joint Utilities observed that the Commission has the authority to raise the SBC or the LDAC to levels it deems just and reasonable, and, because they are already the primary methods of funding the Core programs, changes to those rates can be readily accomplished. Also, funding the EERS primarily through the SBC and LDAC is consistent with how other jurisdictions have funded their EERS programs. In addition, the Joint Utilities opined that third-party financing alone is not as stable or reliable a source of funding as the SBC and LDAC, and will not support the goal of an EERS to significantly increase energy efficiency activity.

The Joint Utilities provided examples of bill impacts to a typical residential electric customer at the current rate and rates based on two increased funding levels. With no change to the SBC, there would be no change to customer bills. Estimated savings, based on 2014 delivery sales at current SBC rate, would be between 0.36 percent and 0.48 percent. With a 50 percent increase to the SBC, from $0.0018 per kWh to $0.0027 per kWh, estimated savings would be between 0.52 percent and 0.68 percent of 2014 delivery sales, and funding would increase by nearly $10 million, increasing a typical residential customer’s bill by $0.56 per month. If the

SBC were doubled to $0.0036 per kWh, estimated savings would be between 0.67 percent and 0.87 percent of 2014 delivery sales, and the increase would provide nearly $20 million of additional funding, increasing a typical residential customer's bill by $1.13 per month. The Joint Utilities did not recommend approval of any specific savings level but stated that, regardless of the level set by the Commission, a uniform rate per kWh should apply to all electric utilities. The Joint Utilities also did not estimate the costs or bill impact of changes to the LDAC.

3. Sustainable Energy Group

According to the Sustainable Energy Group, the existing level of funding for efficiency in New Hampshire is below the amount that is economically efficient, and current funding is insufficient to achieve the Group's recommended targets. In setting funding levels, the Sustainable Energy Group recommended that the Commission address three areas of cost: the recovery of program costs; a mechanism to recover efficiency-related lost revenues; and performance incentives.

The Sustainable Energy Group argued that the utilities or program administrators should be able to collect 100 percent of actual efficiency program costs prudently expended, with any associated carrying costs, in addition to its efficiency-related lost revenues and performance incentives. To the extent practicable, the Sustainable Energy Group recommended that, to eliminate cross-subsidization across customer classes, each customer class (*i.e.*, residential, commercial, and industrial) should contribute to program costs in proportion to spending on programs for the customer class. The Sustainable Energy Group noted that the one exception to linking cost recovery to program expenditures is the low-income program budgets, which should be allocated first, with the remaining budgets allocated proportionally to remaining customer classes.

The Sustainable Energy Group recommended that all ratepayers contribute to efficiency programs, because all customers benefit from them. In terms of how funding is collected, the Sustainable Energy Group recommended that, in order to protect customers and ensure that efficiency spending is generating benefits, efficiency costs should not be included in base rates. Amortizing program implementation costs over a short period of time, however, may be an option if the utilities are allowed to recover carrying costs. The Sustainable Energy Group estimated that by saving 3.1 percent of retail energy sales, New Hampshire ratepayers will save $45 million and thousands of jobs will be created.

The Sustainable Energy Group acknowledged that rate impacts will result from the implementation of efficiency programs regardless of the source of funding, because the utility's fixed costs will be collected over lower billing units. Nonetheless, cost-effective efficiency programs result in lower total bills for ratepayers even if per unit energy rates increase. According to the Sustainable Energy Group, bill impacts do not represent increased societal or ratepayer costs, but rather a shift in the allocation and recovery of sunk fixed costs among ratepayers. Despite those shifts, the Sustainable Energy Group contends that using public funds to invest in energy efficiency results in a more rational and efficient allocation of resources and increases total net economic benefits for the state. To the extent that the Commission considers rate impacts of efficiency funding, it should do so in the larger context of comparative costs for all resource acquisition and their impacts on ratepayers, including the risk of stranded costs and other large fixed capital costs that must be amortized through rates over multiple years, if not decades.

The Sustainable Energy Group recommended that the Commission view "buying" energy efficiency as akin to paying for any prudent acquisition of an energy resource. According to the

Sustainable Energy Group, energy efficiency is widely considered the lowest cost energy resource, meaning that a unit of energy saved through efficiency is less expensive than the total lifetime cost of a unit of energy from other resources such as traditional fossil fuel generation and renewable energy sources, when compared on a consistent and fair basis. This is true, the Sustainable Energy Group argued, even when no economic value is placed on the environmental, health, and economic impacts that are not currently monetized in our economy. In addition, not increasing energy efficiency at this time could disadvantage New Hampshire utility customers in terms of mandatory, socialized regional costs of transmission and distribution expansion due to peak demand. Because other states are investing more in efficiency and distributed generation, their share of the ISO-NE peak load is decreasing and, without more efficiency in New Hampshire, its ratepayers' share of load, and the associated costs, will be proportionately higher.

The Sustainable Energy Group opined that private funding is not a replacement for public funding, in part because numerous barriers exist, including uncertainty and lack of knowledge on the part of investors, the up-front investment required from the customer, and a relatively immature market for efficiency services. According to the Sustainable Energy Group, the barriers to increased private funding may be best addressed by focusing initially on ratepayer-funded energy efficiency to build the knowledge, understanding, trust, and infrastructure that can later support private funding.

4. Acadia

Acadia recommended that the Commission fund the EERS through increases to the SBC and the LDAC. According to Acadia, private financing should not be considered a standalone funding option, because it generally will not have substantial uptake in the absence of ratepayer-funded programs, and it will not capture all cost-effective energy efficiency.

Acadia provided information about the many benefits of increased energy efficiency investment that should be considered against the impacts of associated rate increases. For example, to illustrate that energy efficiency is cheaper than other supply resources, Acadia stated that New Hampshire spent $4.5 billion on fossil fuel imports, at an average cost of $0.14 per kWh, when the average cost of energy efficiency was $0.0226 per kWh. Citing a 2009 study to demonstrate benefits enjoyed by all ratepayers regardless of participation in efficiency programs, Acadia stated that increasing efficiency investments to a level needed to capture all cost-effective electric efficiency over 15 years, or $1.4 billion, would increase economic activity by $14 billion (in 2008 dollars). Likewise, increasing gas efficiency by $219 million over 15 years would increase state economic activity by $4.1 billion. In addition, according to Acadia, all ratepayers benefit from decreases in the cost of generation, because less demand means lower prices in the regional forward capacity market and lower wholesale electricity prices.

5. TRC

TRC described the SBC, LDAC, and other existing mechanisms used to fund energy efficiency in New Hampshire as a solid foundation for structuring an EERS market. TRC's recommendations for funding, however, focused on the proceeds from RGGI auctions, most of which are not available for efficiency by statute.

6. The Way Home

TWH urged the Commission to increase public funding to the extent needed to meet the EERS targets it sets and to maintain the existing percentage allocations of program resources among customer sectors pursuant to the Core plan. According to TWH, without a commensurate increase in funding to accompany more aggressive savings goals, existing programs are put at risk.

TWH described an increase in the SBC and LDAC as the easiest and most equitable means of increasing funding to support an EERS. TWH recommended that the Commission continue its Core practice of first allocating low-income program budgets and then allocating program budgets for remaining customers. In addition, TWH recommended that the Commission consider increasing the low-income allocation above the existing 15.5 percent if private funding of efficiency is expanded under an EERS. According to TWH, allocating more public funding to low-income efficiency measures is consistent with the statutory requirement to "target cost-effective opportunities that may otherwise be lost due to market barriers." RSA 374-F:3, X.

7. Settlement Agreement

To achieve the recommended targets for the 2017 Core extension and the first three-year period of the EERS, the Settling Parties recommend that the Commission increase the SBC and LDAC. Illustrations of the estimated costs of funding the recommended savings goals associated with those periods of time are shown in attachments to the Settlement Agreement. The Settling Parties agree that the costs to fund the EERS include the costs associated with, (1) an independent expert to assist in refining the framework, planning and implementation of the EERS; (2) an independent expert to assist with the oversight and execution of EM&V activities; and, (3) independent experts to conduct the EM&V activities of the individual programs.

In addition, the Settlement Agreement provides for an increase in the minimum low-income share of the overall energy efficiency budget from 15.5 percent to 17 percent. As proposed, the increase would take effect on January 1, 2017, and remain in effect through the first three-year period of the EERS. During that time, the Settling Parties will explore additional funding sources to augment ratepayer funding.

E. Recovery of Lost Revenues

1. Staff

According to Staff, a targeted lost revenue adjustment mechanism (LRAM) or decoupling may be used to compensate utilities for lost revenues associated with energy efficiency. LRAMs limit the recovery to sales revenue lost on account of energy efficiency activity, while decoupling permits the utility to recover the difference between its actual revenues and its authorized revenue requirement no matter the reason. With an LRAM, under certain conditions, a utility may actually earn more than its authorized revenue requirement. With decoupling, the utility would refund to customers any amount that exceeds its authorized revenue requirement. Decoupling also addresses the throughput incentive that traditional ratemaking creates (*i.e.*, higher sales equals higher revenues). Because of Commission policy requiring the consideration of decoupling only within the context of a rate case, Staff recommended the adoption of an LRAM for the initial three-year period, to be replaced thereafter by a decoupling mechanism.

Staff's LRAM included several adjustments: (1) an adjustment that would allow for the recovery of lost revenues through the LRAM only above a specific threshold level to reflect historical Core energy efficiency investment; (2) an adjustment that would reduce the lost revenues recovered through the LRAM by savings associated with the retirement of measures installed in the past; and, (3) for gas utilities only, a fuel-switching adjustment that would reduce the recovery of lost revenues through the LRAM by the amount of new gas revenues associated with program participants who convert from other fuels to high-efficiency natural gas for heating. Staff also recommended that the annual recovery of lost revenues through the LRAM be capped at 0.50 percent of sales revenue and that the costs associated with the LRAM be included in the benefit/cost test used to screen energy efficiency programs. For the first three-year period of the EERS, Staff estimated that its LRAM would increase the costs of energy efficiency by approximately $2 million for the electric utilities and $0 for the gas utilities. Staff recommended recovery of lost revenues determined by the LRAM through the SBC and LDAC.

2. Joint Utilities

The Joint Utilities[8] recommended that the EERS allow for recovery of lost distribution revenues associated with energy efficiency savings, because revenue for all components of service is reduced by implementing energy efficiency measures. That reduced revenue is a consequence of the way utility distribution rates are set, based on an approved revenue requirement, designed using assumptions of a set level of customers, demand, and consumption for each rate class, and collected, in part, through a volumetric charge. Also, between rate cases, there is no reconciliation of actual revenues to the approved revenue requirement. The Joint Utilities contended that the recovery of lost revenues would restore the assumed relationship between sales levels and revenue requirements used in setting rates through historic test year ratemaking. According to the Joint Utilities, costs increase between rate cases, and the loss of sales does not necessarily equate to a similar decrease in the fixed costs used to set rates. Therefore, without recovery of energy efficiency related lost revenues, the utility collects less than its approved revenue requirement.

The Joint Utilities proposed that each recover lost distribution revenues through a Lost Base Revenue Adjustment (LBR Adjustment). The Joint Utilities proposed a formula to calculate the LBR Adjustment for future periods:

[8] For the purpose of this section, references to the Joint Utilities do not include the NHEC. NHEC does not seek recovery of lost revenues, because lost revenue mechanisms primarily address revenue recovery issues associated with distribution rate regulatory processes that apply to investor-owned utilities. Because NHEC is a deregulated, member-owned rural electric cooperative, it is not subject to the same regulation as the other electric utilities.

Total Lost Revenues = Projected Cumulative Electric Savings x Utility's Distribution Rate

Lost Revenue Rate = Total Lost Revenues / Projected Kilowatt Hours

Under their proposal, the LBR Adjustment would be a factor in setting the SBC and LDAC, and lost base revenues would be reconciled annually, when the LBR Adjustment factor is set for the upcoming period. Because each utility's lost revenues may be different, each utility's SBC or LDAC may be different. The Joint Utilities opposed, and described as confiscatory, Staff's recommendations to cap or adjust lost revenues. The Joint Utilities also opposed Staff's recommendation to include lost revenues as a cost within the cost/benefit test for the purpose of screening efficiency programs.

The Joint Utilities contended that the SBC and LDAC are transparent, efficient mechanisms that can be readily implemented to recover lost revenues (as well as to fund the costs of the EERS programs). According to the Joint Utilities, the LBR Adjustment can be established without the need for a distribution rate case and would implement lost revenue recovery coincident with implementation of savings measures. In contrast, a mechanism such as decoupling would require a distribution rate case entailing a lengthy process that requires extensive resources from each utility, Commission Staff, and interested parties. Such a case, the Joint Utilities argued, would consider more than the revenue impacts of energy efficiency in determining the revenue requirement and appropriate rate mechanisms; all aspects of the revenue requirement would come into play, including issues associated with distribution capital investments, operating and maintenance costs, and rate of return. The Joint Utilities opposed implementing decoupling, contending that an LBR Adjustment leaves a utility in the financial position contemplated by its last rate case (*i.e.*, equal to where it would have been absent efficiency activities), no better or worse, and only a lost revenue recovery mechanism isolates the effect on utility revenue of efficiency.

3. Sustainable Energy Group

The Sustainable Energy Group recommended a mechanism to permit recovery of lost revenue resulting from lower energy sales due to efficiency. According to the Sustainable Energy Group, and contrary to the Staff, lost revenue is not a cost of efficiency programs, because lost revenues would have been collected from customers even in the absence of efficiency programs. Instead, recovery of lost revenue from efficiency is simply a shift in how those authorized revenues are recovered from ratepayers.

The Sustainable Energy Group described lost revenue recovery mechanisms as designed to quantify the lost net revenue that can be recovered by the utility. To develop accurate estimates of lost revenue, the Sustainable Energy Group argued that precise evaluation, measurement, and verification are required. Best practices include independent third-party review, frequent rate cases to avoid the “pancake effect” of lost revenue recovery costs accumulating over time, and combining lost revenue recovery with performance incentives sufficient to promote increased utility investment in energy efficiency. The Sustainable Energy Group also suggested that, with an LRAM, performance incentives can be focused solely on exemplary performance. In addition, the Sustainable Energy Group noted that an LRAM allows a utility’s earnings to increase with increased sales and, consequently, it is possible for a utility with an LRAM to have sales in excess of the test year used to set rates (even with reductions from efficiency programs) and earn excess profit as well as collect lost revenues.

The Sustainable Energy Group contrasted an LRAM with decoupling, which seeks to remove the direct connection between sales and revenue, such that the utility’s fixed costs are covered regardless of total energy sales. According to the Sustainable Energy Group, decoupling generally includes a price adjustment to “true up” revenues when sales are different than those forecasted in the rate setting process. The correction of variances should take place at least annually, the Sustainable Energy Group argued, and should accrue to the utility, or credit back to the ratepayers. With decoupling, throughput is fully decoupled from revenue, meaning it accounts for all sales fluctuations not just those related to energy efficiency. The Sustainable Energy Group noted that this could translate into benefits for customers in cases where sales increase.

In the Sustainable Energy Group’s opinion, the symmetrical treatment of revenue requirement recovery using decoupling results in, along with other benefits, the potential for both customer surcharges and refunds, rather than just surcharges, and makes full decoupling preferable to an efficiency specific LRAM. Other benefits include simplifying future rate cases and reducing the volatility of utility revenues. Consequently, the Sustainable Energy Group recommended that the Commission consider moving towards full decoupling, even if LRAM is used as an interim step. Should an LRAM be implemented first, the Sustainable Energy Group opposed incorporating the cap and adjustments that Staff recommended, and the Sustainable Energy Group recommended that the LRAM be reconciled annually.

4. Acadia

Acadia recommended that the Commission establish decoupling for the Joint Utilities in their next rate cases. Under decoupling, customers would pay two charges: one for the energy they use; and the other for the costs of the distribution system used to deliver the energy. Distribution charges would be adjusted annually so that the utility does not collect more or less than it is allowed by the Commission. According to Acadia, decoupling complements performance incentives.

Acadia discussed Staff's recommendation of an LRAM for the initial three-year period, to be transitioned into decoupling. Acadia agreed with that approach but opposed Staff's retirement and fuel-switching adjustments. In addition, Acadia urged Staff to support decoupling in the next rate case for each utility.

5. The Way Home

TWH supported the Joint Utilities' general parameters for recovery of lost distribution revenue associated with higher levels of energy efficiency savings, and it supported the implementation of a lost revenue adjustment mechanism in the short term. TWH indicated it would take a position on Staff's recommendation to transition such a mechanism to decoupling, when a more comprehensive decoupling rate structure is proposed.

TWH agreed with the Sustainable Energy Group's (and the Joint Utilities') recommendation that lost net revenue recovery not be treated as a cost in the cost/benefit test used for efficiency programs. Doing so, TWH stated, might make it difficult to achieve energy efficiency savings comparable to neighboring states and could result in the low-income Home Energy Assistance program, and perhaps other efficiency programs, being mistakenly labeled as cost ineffective in the future.

TWH also agreed with the Sustainable Energy Group that the most equitable way of recovering lost revenue is through increases to the volumetric charges, not the fixed charges, on customer bills. According to TWH, increasing the fixed charges disproportionately harms low-income ratepayers least able to absorb them, and acts as a disincentive to customer conservation efforts and energy efficiency program participation.

6. Settlement Agreement

The Settling Parties recommend that the Commission implement an LRAM for effect January 1, 2017 and that the LRAM continue after implementation of the EERS. The LRAM will be designed and implemented consistent with the Joint Utilities' proposal, the details of which are summarized above. In addition, the Settlement Agreement requires total recovery through the LRAM to be capped at 110 percent of planned annual savings; savings to be adjusted to account for the actual month the measures are installed within the year of installation and for the results of EM&V studies.[9] The Settlement defines the rate used to calculate LRAM recovery (*i.e.*, the "Utility Distribution Rate" in the Joint Utilities' proposed formula) to be an average distribution rate excluding customer charges.

The Settling Parties recommend, for each utility's rate cases following the implementation of the LRAM, that the savings used to calculate the utility's lost revenue be reset to zero. They also recommend that in each utility's first rate case following the first three-year period of the EERS, the utility seek approval of a new decoupling mechanism as an alternative to the LRAM, and that the LRAM cease when the new mechanism is implemented.

F. Performance Incentives

1. Staff

Staff recommended including performance incentives (PI) in the EERS framework to incent the Joint Utilities' investment in energy efficiency. According to Staff, performance incentives place energy efficiency and supply-side investments on a relatively equal financial footing and enables utility shareholders to earn a comparable return on either investment. Staff also noted the vital role of PI in the success of the Core programs.

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[9] The Settlement Agreement does not incorporate Staff's proposed threshold, retirement, and fuel-switching adjustments to the LRAM, or Staff's recommendation to include lost revenues as a cost for the purpose of determining the cost/benefit ratio of the 2017 Core and EERS programs.

Staff recommended 10 percent of annual budgets as an appropriate PI cap for both the electric and gas utilities. The 10 percent cap is the same as the existing Core PI cap for electric utilities, and it is 2 percent less than the existing 12 percent Core PI cap for gas utilities. Staff asserted that the PI cap for electric and gas utilities should be the same, because the Commission's energy efficiency programs are statewide. Staff further supported the reduction to the gas PI cap by considering it in relation to the PI caps in other New England states, which are all lower than 10 percent. To calculate PI, Staff recommended continuation of the existing (*i.e.*, Core program) cap on actual spending at 5 percent of budgeted spending. In addition, Staff recommended that the Commission review the PI level after the first triennium of the EERS, when it has data on the impact of the LRAM on the Joint Utilities' energy efficiency activities.

2. Joint Utilities

The Joint Utilities proposed that the Commission maintain the current Core PI mechanism and levels. Under their proposal, the Joint Utilities' performance would continue to be evaluated against both the achievement of the defined savings and the cost-effectiveness targets. The methodology would be based on actual program expenditures with threshold and maximum performance payout levels. The Joint Utilities contend that the existing mechanism is easy for stakeholders to understand, effectively tracks performance, and appropriately focuses on the primary factors that are most pertinent to rewarding performance. In response to the Order of Notice, the Joint Utilities opposed incorporating penalties into the EERS framework, contending that the failure to earn PI constitutes sufficient financial detriment.

3. Sustainable Energy Group

The Sustainable Energy Group recommended that the EERS provide performance incentives to allow the Joint Utilities a reasonable incentive to pursue exemplary performance and to make efficiency investments attractive relative to other available investment opportunities. The design of the incentive mechanism, the Sustainable Energy Group stated, should ensure that ratepayers are protected from providing excessive earnings levels beyond those necessary to create that incentive and equal footing. PI should be commensurate with the lower risk of investing in efficiency as compared to supply-side investments, and to the extent existing PI levels include compensation for lost revenues, they should be reduced.

The Sustainable Energy Group discussed several PI models used in other jurisdictions and noted that New Hampshire already uses one model for the Core programs, a performance target incentive. Regardless of the model used in the EERS, it should include clearly articulated earnings and/or penalties, based on tangible, measurable performance that is under some control of the utility or program administrator. Also, the Sustainable Energy Group recommended that the performance incentive metrics be defined in a way that achieves efficiency policy objectives and guards against perverse incentives that could lead to undesirable policy outcomes. The Sustainable Energy Group noted that incentive designs where multiple parameters can be rewarded or penalized, are one way to protect against perverse effects.

4. Acadia

Acadia described PI as essential to maximizing investment in efficiency and demand-side resources. Acadia linked decoupling with PI, suggesting that decoupling enhances the effect of PI. Acadia opposed the PI levels recommended by Staff, contending that if a lost revenue recovery mechanism is approved for the EERS, PI should be more in line with neighboring states, or between 2 percent and 8 percent.

5. The Way Home

TWH supported providing the opportunity to the Joint Utilities (or other program administrator) to earn performance incentives when the Core programs transition to an EERS, because the incorporation of a reasonable PI is consistent with the policy of treating energy efficiency as a supply resource. TWH suggested, however, that if a lost revenue recovery mechanism is implemented, the Commission may want to consider reducing the current Core levels of PI, because such a mechanism shifts risk away from the utility to the ratepayer by guaranteeing the recovery of certain revenues.

6. Settlement Agreement

The Settlement Agreement recommends PI for the Joint Utilities at a target level of 5.5 percent and a maximum level of 6.875 percent of spending. Those PI levels should be effective when the LRAM is implemented, or January 1, 2017, and should remain unchanged at least through the first three-year period of the EERS. In addition, prior to the filing of the first EERS plan, the Settling Parties would review the existing PI formula and consider the way it values achievements of low-income programs. The Settling Parties agree that any recommendations for modifications to the PI formula may be included in that filing or proposed during the Commission's review of that filing.

G. Stakeholder Involvement

1. Staff

Staff recommended the creation of a permanent EERS Advisory Council made up of a broad group of stakeholders representing a variety of interests. Staff asserted that other jurisdictions use stakeholder groups to develop consensus and energy efficiency policy recommendations. According to Staff, the Advisory Council should include representatives from the utilities, the Commission and DES, the OCA, environmental groups, customers, energy efficiency program providers, and consultants. Staff recommended that the Commission designate the existing Energy Efficiency and Sustainable Energy (EESE) Board as the Advisory Council and authorize the recovery of funds through the SBC and LDAC for its administrative and technical support. Specifically, Staff recommended the use of an independent consultant to facilitate the Advisory Council's work and expert consultants as necessary. Staff envisioned the Advisory Council's work as including annual reports on energy efficiency achievements, coordination of studies, and development of a Technical Resource Manual (TRM). The TRM, according to Staff, would include New Hampshire specific EM&V protocols and reporting forms.

2. Joint Utilities

The Joint Utilities recognized the wide range of stakeholders who work with them to plan, deliver, and evaluate the Core programs. Stakeholders include retailers, manufacturers, equipment distributors, contractors, builders, architects, engineers, trade associations, non-profit organizations, policy makers, program evaluation vendors, and customers. According to the Joint Utilities, the stakeholders' contributions are essential to the success of the programs. Under an EERS, the Joint Utilities, like Staff, recommended that the EESE Board function as an energy efficiency stakeholder board. The Joint Utilities view the roles, responsibilities, and membership of the EESE Board as very similar to the EERS stakeholder boards in other states. EESE Board membership includes energy efficiency and sustainable energy stakeholders, state policy makers, representatives of the business community, and utility program administrators.

Similar to Staff, the Joint Utilities recommended additional resources for the EESE Board in its new role as EERS advisor. Specifically, the Joint Utilities suggested the dedication and funding of an administrative employee and the engagement of specialized organizations such as Northeast Energy Efficiency Partnerships (NEEP) and Regulatory Assistance Project (RAP).

3. Sustainable Energy Group

To oversee and guide efforts to implement the requirements of an EERS, the Sustainable Energy Group also recommended an advisory body with sufficient resources and authority to ensure robust stakeholder involvement and to assist the Commission. According to the Sustainable Energy Group, Commission proceedings are too cumbersome to provide a forum where inclusive, informed discussions and decisions necessary to implement best practice energy efficiency programs can be conducted.

The Sustainable Energy Group recommended that the advisory body's membership include a wide range of stakeholders to ensure a balance of interests in efficiency oversight. Stakeholders should include all customer classes (individually represented), state environmental policy staff, Commission staff, consumer protection agencies, advocacy groups in the energy and environmental fields, and the energy efficiency industry. According to the Sustainable Energy Group, the Joint Utilities should be active participants in the advisory body but should not have voting privileges.

The Sustainable Energy Group noted that the EESE Board includes some features important to a robust advisory body (*e.g.*, diverse membership), but it currently has little authority and no staff or funding. To be effective, the EESE Board will need guidance from experts in energy efficiency planning, evaluation, program design, and implementation. In addition, because the members will likely have full-time jobs and will only serve in a voluntary capacity, administrative and technical support is needed to manage and conduct the basic operations and analysis of the group. According to the Sustainable Energy Group, some jurisdictions contract for administrative support and expert resources.

4. Acadia

Consistent with the positions of others, Acadia also recommended that the Commission supplement the adjudicative process it uses for energy efficiency with a stakeholder council or board to oversee planning and administration of statewide programs through a collaborative process. Doing so ensures that the programs enjoy a broad base of support and reduces the duration and complexity of the approval process at the Commission. Acadia stated that in other states in the Northeast, stakeholder boards may spend six months or more in a collaborative plan development process with the utilities before filing plans for approval. According to Acadia, using a stakeholder body to guide efficiency investment will also reinforce high standards for programs, because the stakeholders are end users. Acadia also recommended that the advisory body have access to expert resources to balance the utilities' access to information and expertise. The EESE Board, Acadia stated, could be transitioned into an advisory body role if adequate funding is made available for such resources.

5. The Way Home

TWH echoed the recommendation of others that the EESE Board be used as an advisor to the Commission in its implementation of an EERS. TWH also observed the EESE Board's limited statutory authority and need for resources, but suggested that those limitations may be overcome by the Commission specifically designating the EESE Board's role in its order approving the EERS.

6. Settlement Agreement

The Settlement Agreement specifically provides opportunities for the EESE Board to actively participate in the development of the EERS programs within the proposed EERS framework, and in the Commission-supervised EM&V activities under the EERS. The Settlement Agreement also recommends EESE Board access to the independent planning and EM&V oversight experts.

H. Evaluation, Measurement and Verification

1. Staff

Staff considers EM&V a vital part of a successful EERS program, for program transparency and credibility. Staff described evaluation as the performance of studies and activities aimed at determining the effects of an energy efficiency program or portfolio. Measurement and verification, according to Staff, constitutes data collection, monitoring, and analysis associated with the calculation of savings from individual projects. EM&V according to Staff, ensures that the Joint Utilities are actually meeting the savings targets and spending ratepayer funds in a just and reasonable manner, and that energy efficiency programs are cost effective. Currently, the Joint Utilities administer EM&V to monitor and manage the Core programs.

To enhance EM&V under an EERS framework, Staff recommended that funding be set aside for independent consultants and for the development of a New Hampshire technical resource manual. Staff noted recent efforts in New England to develop consistent protocols and reporting for EM&V, which could be adopted where feasible. In addition, Staff recommended that the EESE Board in its role as an EERS Advisory Council guide EM&V, and that the results of EM&V impact studies be used to update savings assumptions and program design.

2. Joint Utilities

The Joint Utilities described EM&V practices for the Core programs, which include stringent and transparent reporting regarding their achievement of planned savings, participation, and cost-effectiveness goals, verification of results, onsite inspections, independent third-party market assessments, program process and impact evaluations, and annual financial audits. According to the Joint Utilities, the existing practices hold them to high standards of accountability and verification, which includes several layers of quality control.

For an EERS with increased savings goals, the Joint Utilities, like Staff, recommended that the Commission hire an independent consultant to help guide energy efficiency evaluation activities. Accordingly, the consultant would create an implementation plan and review and adjust evaluation priorities. The Joint Utilities suggested that the consultant's review could include consideration of the Environmental Protection Agency's Clean Power Plan as well as the standardization of EM&V reporting forms.

The Joint Utilities proposed that they manage the evaluation activities under the Commission's oversight. In support of their proposal, the Joint Utilities cited their procurement and contract management capabilities, which allow them to act efficiently and cost effectively. Citing a recent example, the Joint Utilities contended that their existing relationships with EM&V consultants and colleague counterparts from among their affiliates in other states will help them coordinate evaluation activities and identify best practices, current challenges, and opportunities.

3. Sustainable Energy Group

The Sustainable Energy Group opined that the success of an EERS can only be measured by assessing the extent to which energy reduction targets are actually realized. The key concepts and requirements of EM&V, according to the Sustainable Energy Group, include rigor, transparency, and independent third-party verification, to ensure consistent and fair assessment of program performance. The Sustainable Energy Group recommended that the achievement of savings targets and earning of performance incentives be evaluated on the same basis for the sake of efficiency and fairness. In addition, the Commission and its advisory body should oversee EM&V services.

4. The Way Home

TWH generally concurred with the EM&V recommendations of other parties. In addition, TWH noted the one measurement consideration specific to low-income residential ratepayers, which is that low-income programs may fall below a benefit cost ratio of 1.0 under the Total Resource Cost test and still be approved by the Commission.

5. Settlement Agreement

The Settlement Agreement requires EM&V studies to be conducted by independent third parties retained and supervised by the Commission with the advice and participation of the Settling Parties and the EESE Board. If requested, an independent expert, separate from the independent planning expert required by the Settlement Agreement, would facilitate the Settling Parties' and the EESE Board's participation in, and provide oversight of, the EM&V study activities. One specific deliverable of the EM&V expert will be assisting with the development of a New Hampshire-specific technical resource manual by the end of the first EERS triennium.

I. Regulatory Process

1. Staff

Staff recommended leveraging the exiting Core mechanisms to transition to an EERS framework. According to Staff, the Joint Utilities, as administrators, would prepare the triennial

EERS plans in collaboration with stakeholders and the EESE Board as Advisory Council, for review and approval by the Commission. Staff also recommended annual reviews during the three-year EERS periods. Those reviews, according to Staff, should include updating savings assumptions based on the results of EM&V studies. In addition, Staff recommended continuing practices developed for the Core program, including the processes for budget transfers and carrying forward unspent funds.

2. Joint Utilities

The Joint Utilities proposed developing savings targets for the EERS through a comprehensive process that validates savings targets feasibility and provides a detailed plan for specific programs. Savings target development, however, would follow an annual determination by the Commission of the funding levels. According to the Joint Utilities, the Commission uses such a process currently to set the LDAC rate for gas utilities.

The Joint Utilities proposed that, each year of the EERS, they prepare and submit to the EESE Board a draft energy efficiency plan for its review before a final plan is filed with the Commission for approval. That process would allow collaboration between the EESE Board and the Joint Utilities in a non-adjudicative setting, which the Joint Utilities believe could result in a more efficient Commission proceeding. According to the Joint Utilities, the Commission's regulatory role of overseeing the state's energy efficiency programs would continue in its current form. The Commission would determine if the final plans submitted by the Joint Utilities are in the public interest, including the program budgets and program cost effectiveness. In addition, the Commission would continue to oversee ongoing reporting and implementation and results of the programs.

The Joint Utilities propose that each utility, except NHEC, file its own request for recovery of EERS-related lost revenues, which will vary by utility each year and that the Commission adjudicate the requests individually. According to the Joint Utilities, the LBR Adjustment process would be separate from the three-year planning process used to set savings targets and to establish specific programs to meet those goals.

3. The Way Home

TWH recommended regular review of the efficiency programs during the three-year EERS planning periods, perhaps quarterly as is currently done for the Core programs. TWH also recommended an annual planning process.

4. Settlement Agreement

The Settling Parties recommend that they work collaboratively to refine a draft plan for the first triennium of the EERS, which will be filed for Commission review and approval by September 1, 2017. An independent consultant would be hired by the Commission, with a budget not to exceed $95,000 annually, to assist in the development of the initial and subsequent EERS plans. The consultant would serve as a resource to the EESE Board and other stakeholders as requested and deemed appropriate by the Commission.

The Settlement Agreement requires the filing of annual updates during the three-year EERS plan periods, for Commission review and approval. The review process would be akin to the process currently used to review mid-period submissions in the Core dockets. Such annual update filings will serve as an opportunity to adjust programs and targets and address any other issues that may arise from changes or advancements, including evaluation results, state energy code changes, and federal standard improvements.

The Settlement Agreement and the Joint Utilities' proposal provide specific detail about the processes to be followed with regard to lost revenue recovery, including the annual setting of a rate for the next year and the reconciliation of the prior year's rate and revenue recovery. The Settlement Agreement also requires actual savings and costs to be audited by an independent third party.

J. Implementation Date

1. Staff

Staff recommended an EERS implementation date of January 1, 2017.

2. Joint Utilities

The Joint Utilities recommended that the EERS be implemented beginning January 1, 2018. According to the Joint Utilities, adequate time is needed for thorough program development and a more comprehensive stakeholder review process than is typically used for the Core programs. Under their proposal, the Joint Utilities would present a draft three-year plan to the EESE Board on April 1, 2017, and allow two months for EESE Board's review. Then, the Joint Utilities would file the final plan with the Commission by September 30, 2017, for approval by December 31, 2017. Also before implementation of the EERS, the Commission would determine the SBC and LDAC funding rates.

In the meantime, the Joint Utilities proposed to file, on or before September 30, 2016, an interim, one-year Core plan for 2017. Also by that date, the Joint Utilities would file testimony regarding the implementation of their LBR Adjustment.

3. Sustainable Energy Group

The Sustainable Energy Group did not specifically recommend an implementation date. In discussing savings targets, however, the Group referred to the first three-year period of the EERS as 2017-2019.

4. Settlement Agreement

The Settlement Agreement proposes the implementation of an EERS beginning January 1, 2018. During 2017, the Core programs will continue, and the Settling Parties, in collaboration with the EESE Board, will prepare for EERS implementation.

K. Beyond Implementation

1. Staff

Staff described energy efficiency programs and products that are available in other jurisdictions, but not New Hampshire. Staff suggested that some or all of those offerings could be used to enhance an EERS. According to Staff, the Joint Utilities could use the integrated resource planning process to identify new opportunities for energy efficiency. In addition, demand-side management and grid modernization tie well with energy efficiency programs.

2. Joint Utilities

The Joint Utilities described their vision for the future of the EERS and provided examples of expanded program services, new initiatives, and innovative implementation strategies. The examples included piloting emerging technologies, offering incentives for combined heat and power projects, and incorporating the use of midstream and upstream program delivery models, which allow for energy efficiency equipment incentives at the retailer and manufacturer level.

The Joint Utilities also discussed potential sources of funding for the EERS other than the SBC and LDAC, including the Commercial Property Assessed Clean Energy (C-PACE) program. According to the Utilities, C-PACE falls under third-party financing, specifically for commercial buildings, and allows building owners to finance cash-positive energy efficiency and renewable energy projects, tying the financing to the property through a voluntary, municipal special assessment/lien. The Joint Utilities argued that C-PACE could work in combination with the programs under an EERS.

3. Sustainable Energy Group

To ensure that the benefits of peak demand reduction are realized for all ratepayers, the Sustainable Energy Group recommended that the Commission consider establishing cost-effective peak shaving demand reduction programs.

4. TRC

TRC recommended that the EERS broaden the customer base that is reached by the existing efficiency programs and provide the opportunity for all contributors to program funding to receive program benefits. TRC recommended that the EERS include hybrid programs that effectively address both electricity and fuel savings, because they introduce building owners to deeper energy savings projects.

5. OCA

The OCA recommended that all residential ratepayers participate in a single, statewide customer engagement technology platform (CETP) akin to the platform being developed by Eversource and partially funded through the Core budget. According to the OCA, a CETP is a web-based, data-diagnostic tool that utilities can use in many ways including to educate customers about energy efficiency, target marketing efforts, institute customer behavioral programs, and offer customers online self-service options. The OCA contended that the outcome of using a CETP statewide would be uniform delivery and reduced costs of efficiency services; broader customer participation in efficiency; and greater energy savings for all customers. In addition, a CETP will be needed in the future should the Commission implement programs such as net metering and time-of-use pricing.

6. The Way Home

TWH recommended that the Commission consider quantifying, for the purpose of the cost/benefit test used for efficiency programs, additional non-energy benefits or societal benefits derived from low-income efficiency programs, which are not currently accounted for under that test. According to TWH, a 2008 New Zealand study confirmed benefits such as reduced hospitalizations, and lost days of work and school, and the states of Vermont and Ohio use adders in their cost-benefit tests to quantify non-energy benefits including greater comfort, improved health, enhanced productivity, and other societal benefits.

IV. COMMISSION ANALYSIS

A. Legal Authority

RSA 4-E:1 became effective on July 24, 2013, and spurred the opening of this docket. That statute required the Governor's Office of Energy and Planning (OEP) to prepare a 10-year energy strategy for the State. RSA 4-E:1. The Legislature required the state energy strategy to include "consideration of the extent to which demand-side measures including efficiency … can cost-effectively meet the state's energy needs, and proposals to increase the use of such demand resources to reduce energy costs and increase economic benefits to the state." RSA 4-E:1, II. As detailed in Section I above, OEP prepared the 2014 New Hampshire State Energy Strategy in response to that legislative mandate. The Energy Strategy final report recommended that the

Commission open a proceeding to establish "energy efficiency savings goals based on the efficiency potential of the State, aimed at achieving all cost-effective efficiency over a reasonable time frame." 2014 New Hampshire State Energy Strategy, Executive Summary at ii.

Although RSA 4-E:1 and the 2014 New Hampshire State Energy Strategy served as catalysts for this docket, the Commission has a long history of regulating the demand-side measures of the State's electric and gas utilities. The Commission has historically regulated demand-side measures, including energy efficiency programs, pursuant to its general authority under RSA 374:3 (general supervision of all public utilities) and RSA Chapter 378 (rates and charges). In 1988, pursuant to both its general authority and its authority under the New Hampshire Limited Electric Energy Producers Act, RSA Chapter 362-A, the Commission required that electric utilities engage in least cost integrated resource planning (LCIRP). In *Public Service Company of New Hampshire, et al.*, 73 NH PUC 117 (1988), the Commission required electric utilities to "file an integrated least cost resource plan in conjunction with an updated forecast of avoided costs in order that the commission may reasonably review each utility's planning process, resultant plans, and avoided cost forecast." *Id.* at 126.

Shortly thereafter in 1990, the Legislature enacted the LCIRP statute, RSA 378:37-39, and declared least cost integrated resource planning for electric utilities to be the energy policy of the state. As originally enacted, RSA 378:37 provided that:

> The general court declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; the protection of the safety and health of the citizens, the physical environment of the state, and the future supplies of nonrenewable resources; and consideration of the financial stability of the state's utilities.

RSA 378:37 (West 2009).

Although the LCIRP statute has always required our review of utility demand-side programs, including energy efficiency, the Legislature amended the LCIRP statute in 2014 to place a greater emphasis on evaluation of energy efficiency programs. *See* Laws of 2014 ch. 129; *compare* RSA 378:38, II (West 2009) *with* :38, II (West Supp. 2015). In the 2014 amendment, the Legislature declared it the energy policy of the state "to maximize the use of cost effective energy efficiency and other demand side resources." RSA 378:37 (West Supp. 2015). The 2014 amendment increased the emphasis on energy efficiency programs by providing that the Commission's evaluation of utility plans should be guided by certain energy policy priorities, energy efficiency being first and foremost among them. RSA 378:39 (West Supp. 2015).

In addition, the electric restructuring policy principles, enacted in 1996, guide the Commission in the exercise of its general authority over electric utilities. *See* RSA 374-F:3, X (restructured electric market required to "reduce market barriers to investments in energy efficiency and provide incentives for appropriate demand-side management and not reduce cost-effective customer conservation" and "utility sponsored energy efficiency programs should target cost-effective opportunities that may otherwise be lost due to market barriers"); RSA 374-F:4, VIII(e) (Commission authorized to approve a utility's inclusion in its distribution charge of the costs of energy efficiency "that are part of a strategy to minimize distribution costs"). Specifically, RSA 374-F:3, VI authorized the creation of a "nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system" for the support of, among other things, energy efficiency programs.

The Commission has reviewed gas utility demand-side measures pursuant to its general authority since at least 1992. *See, e.g., EnergyNorth Natural Gas, Inc.*, 77 NH PUC 802 (1992);

Northern Utilities, Inc., 77 NH PUC 803 (1992); *see also Northern Utilities, Inc*., 78 NH PUC 310 (1993) (approving pilot DSM program); *EnergyNorth Natural Gas, Inc.*, 79 NH PUC 605 (1994) (same); *EnergyNorth Natural Gas, Inc. et al.*, Order No. 24,109 at 1 (December 31, 2002) (approving gas utility energy efficiency programs following gas industry restructuring). The 2014 amendment to the LCIRP statute has since made that statute's energy efficiency requirements applicable to gas utilities. *See* RSA 378:38.

While nothing prohibits electric utilities from funding energy efficiency programs through their distribution rates as approved by the Commission under its general rate making authority, *see* RSA 374-F:4, VIII(e), electric utilities fund energy efficiency measures primarily through the SBC, pursuant to the Commission's authority under RSA 374-F:3, VI. Gas utilities continue to fund energy efficiency programs primarily through the LDAC as approved by the Commission pursuant to the Commission's general supervisory and rate making authority. *See EnergyNorth Natural Gas, Inc., and Northern Utilities, Inc*., Order No. 24,109, at 9 (December 31, 2002). In addition, limited proceeds from the RGGI, pursuant to RSA 125-O:23, and the ISO-NE Forward Capacity Market, are used to fund energy efficiency. In recent years, the Commission has approved the use of third-party private financing options to fund energy efficiency measures. *See* Order No. 25,747 at 9 (describing third-party financing proposals approved by the order).

Electric and gas utility programs are currently reviewed jointly as part of the Core Energy Efficiency Program. *See Electric and Gas Utilities*, Order No. 25,747 (December 31, 2014) (approving 2015-2016 Core programs); *Electric and Gas Utilities*, Order No. 25,462 (February 1, 2013) (approving 2013-2014 Core programs); *Electric and Gas Utilities*, Order No. 25,189 (December 30, 2010) (approving the 2011-2012 Core programs and listing, at page 21, the Commission's energy efficiency orders from 2001 through 2009). As detailed in Section I, above, however, several studies have concluded that additional opportunities for cost-effective energy efficiency exist beyond those attained through the Core program. Accordingly, we opened this docket to consider ways to transition from the Core program to an EERS. The Commission's general supervisory and ratemaking authority, historic energy efficiency program management, and legislative policy pronouncements, provide an adequate legal framework for the creation and financing of the next generation of energy efficiency measures.

B. Settlement Agreement

Pursuant to RSA 541-A:31, V(a), informal disposition may be made of a contested case at any time prior to the entry of a final decision or order, by stipulation, agreed settlement, consent order, or default. We encourage parties to settle issues through negotiation and compromise because it is an opportunity for creative problem solving, allows the parties to reach a result in line with their expectations, and is often a better alternative to litigation. *Granite State Electric Co.*, Order No. 23,966 at 10 (May 8, 2002); *see* RSA 541-A:31, V(a) ("informal disposition may be made of any contested case … by stipulation [or] agreed settlement"). Even when all parties join a settlement, however, we must independently determine that the result comports with "applicable standards." *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,* Order No. 24,972 at 48 (May 29, 2009). We analyze settlements to ensure that a just and reasonable result has been reached. *Id.*; *see* N.H. Code Admin. Rules Puc 203.20(b) ("The commission shall approve a disposition of any contested case by stipulation [or] settlement … if it determines that the result is just and reasonable and serves the public interest.").

Based on the record, the terms of the Settlement Agreement appear to be consistent with applicable law, because they will reduce market barriers to investment in cost-effective energy efficiency investment, provide incentives for appropriate demand-side management, and not reduce cost-effective consumer conservation. *See Electric Utility Restructuring,* Order No. 23,574 (Nov. 1, 2000) at 10 (citing the requirements of RSA 374-F:3, X).

The record supports a finding that cost-effective energy efficiency is a lower cost resource than other energy supply.[10] In addition, over the past 14 years the Commission has used a cost effectiveness, or cost benefit, test for energy efficiency measures in the Core energy efficiency programs. The cost benefit test calculates the cost of acquiring and installing an energy efficiency measure, spread over the expected useful life of the measure, and compares that cost to the cost of the energy saved, or the energy supply avoided, over the expected useful life of the measure. Using the cost benefit test in the Core programs, the Commission has approved numerous Core energy efficiency measures where the cost of the measure is less than the cost of the avoided energy supply.

For avoided costs of supply, we rely on the *Avoided Energy Supply Costs in New England: 2015 Study* (March 27, 2015, revised April 3, 2015) prepared by TCR Group for the Avoided Energy Supply Component (AESC) Study Group (AESC 2015 study) and used in the Core programs to evaluate cost effectiveness.[11] The AESC 2015 study indicates that direct avoided retail electric costs are approximately $0.11 per kWh on a 15-year levelized basis. *See* *2016 New Hampshire Statewide Core Energy Efficiency Plan,* Docket No. DE 14-216, Hearing Exhibit 5 at 20 (December 15, 2015). For the costs of energy efficiency, we use both the utilities' and the customers' costs. The Joint Utilities calculated the utilities' costs of energy efficiency to be $0.030 per kWh saved over the life of the measure. *See* Exh. 3 Joint Utilities at

[10] *See* Exh. 2 Sustainable Energy Group at 5 and Attachment 1; Exh. 3 Joint Utilities at 32; and Exh. 5 Acadia Center at 1.
[11] The Commission takes administrative notice of this analytical tool used in the Core Docket, DE 14-216 pursuant to Puc 203.27 (a)(2) (notice of relevant portion of the record in other proceedings).

32. The customer costs are currently estimated in the Core programs as $0.02 per kWh saved over the life of the measure.[12] Based on the experience with the Core programs, even with the customer costs added to the utilities' costs of energy efficiency, the total costs of energy efficiency are less than the costs of supply. *See id.* at 22, 30, 35 and 40.

As discussed above, the Commission has consistently imposed a cost-effectiveness test before including energy efficiency measures in the Core Programs. Cost effectiveness is a statutory requirement for least cost planning. We will continue to require that all measures used to achieve an EERS meet cost-effectiveness tests. By ensuring that EERS measures are cost effective, we remain consistent with the Legislature's mandate that the Commission prioritize energy efficiency and demand-side supply resources in order to provide the lowest reasonable cost energy supply to customers, RSA 378:37 and :39, and with New Hampshire's Energy Policy, as well as the requirement to set just and reasonable rates, RSA 378:7.

The parties asserted that energy efficiency has a multitude of customer benefits, including lower utility bills now and in the future, improvements in comfort, health, and safety, more customer control and understanding of energy use, increased reliability of the grid and avoidance of new generation capacity, and job creation and reduced pollution. *See* Exh. 5 Acadia Center at 1; Exh. 2 Sustainable Energy Group, Attachment at 1; Exh. 3 Joint Utilities at 38 and 46; Exh. 4 Staff at 14; Exh. 8 Sustainable Energy Group at 8; and Exh. 11 The Way Home at 9. While those benefits have not yet been quantified by the Commission for New Hampshire, we will monitor the cost effectiveness of the energy efficiency measures installed under the EERS and will review the results of the EERS over time to determine its effect on customers.

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[12] The estimated customer costs include kilowatt-hour savings for electric programs, and MMBtu savings – converted to kilowatt-hour-equivalent savings – for gas programs.

In addition to the cost effectiveness of the EERS measures, we must consider the impact on customers of funding the EERS through the SBC and LDAC. The Settlement quantifies the increases to the SBC for each electric utility. It also estimates the corresponding bill impacts for average users. The bill impact calculations do not take into account customer savings due to energy efficiency programs. The SBC and bill impact estimates are as follows.

- The SBC for Eversource will increase from the current rate per kWh of $0.00330 to $0.00383 in 2017, $0.00488 in 2018, $0.00631 in 2019, and $0.00850 in 2020. Exh. 1 at 22. The impact of those increases on an average residential customer using 625 kWh per month[13] will be $0.33 in 2017, $0.65 in 2018, $0.90 in 2019, and $1.37 in 2020. *Id*. The impact of those increases on an average General Service customer using 10,000 kWh per month will be $5.34 in 2017, $10.41 in 2018, $14.34 in 2019, and $21.88 in 2020. *Id*.
- The SBC for Liberty electric customers will increase from $0.00330 to $0.00381 in 2017, $0.00480 in 2018, $0.00615 in 2019, and $0.00825 in 2020. Exh. 1 at 23. The impact of those increases on an average residential customer using 625 kWh per month will be $0.32 in 2017, $0.61 in 2018, $0.85 in 2019, and $1.31 in 2020.[14] *Id*. The impact of those increases on an average Liberty General Service customer using 10,000 kWh per month will be $5.13 in 2017, $9.83 in 2018, $13.58 in 2019, and $20.94 in 2020. *Id*.
- The SBC for UES will increase from $0.00330 to $0.00384 in 2017, $0.00486 in 2018, $0.00626 in 2019, and $0.00841 in 2020. Exh. 1 at 24. The impact of those increases on an average residential customer using 625 kWh per month will be $0.34 in 2017, $0.64 in

[13] We recognize that the Settlement calculates bill impacts using 625 kWh per month for Residential customer usage and 10,000 kWh per month for General Service customer usage, and the Staff used different average usage to calculate the bill impacts in their proposal. Staff used 700 kWh per month for residential usage and 7,000 for commercial/industrial usage. *See* Exh. 4 Staff at 45-46. We note that the Joint Utilities used the same usage that we use in this order to calculate bill impacts. *See* Exh. 3 Joint Utilities Attachment 1, at 70.
[14] Settlement Electric Attachment A, revised page 7 of 10 (Bates page 23), *also* Liberty's response to Record Request 1 (July 27, 2016).

2018, $0.88 in 2019, and $1.34 in 2020. *Id*. The impact of those increases on an average UES General Service customer using 10,000 kWh per month will be $5.41 in 2017, $10.17 in 2018, $14.01 in 2019, and $21.51 in 2020. *Id*.

- The SBC for NHEC will increase slightly less than the SBC increases for the other electric utilities, because NHEC will not recover lost revenues. Specifically, NHEC's SBC will increase from $0.00330 to $0.00376 in 2017, $0.00459 in 2018, $0.00575 in 2019, and $0.00759 in 2020. Exh. 1 at 25. The impact of those increases on an average residential customer using 625 kWh per month will be $0.29 in 2017, $0.52 in 2018, $0.72 in 2019, and $1.15 in 2020. *Id*. The impact of those increases on an average NHEC General Service customer using 10,000 kWh per month will be $4.60 in 2017, $8.30 in 2018, $11.60 in 2019, and $18.40 in 2020. *Id*.

The Settlement also quantifies the increases to the LDAC by utility as follows.

- The LDAC for Liberty gas will increase from $0.0585 to $0.0643 in 2017, $0.0724 in 2018, $0.0817 in 2019, and $0.0907 in 2020. Exh. 1 at 27. The monthly impact of those increases on an average residential customer using 783 therms per month will be $0.38 for 2017, $0.53 for 2018, $0.60 for 2019, and $0.59 for 2020. *Id*. For an average Commercial and Industrial customer using 8,773 therms, the monthly impact will be $2.22 for 2017, $2.98 for 2018, $3.42 for 2019, and $3.30 for 2020. *Id*.
- The LDAC for Northern will increase from $0.0297 to $0.0347 in 2017, $0.0405 in 2018, $0.0466 in 2019, and $0.0576 in 2020. *Id*. The monthly impact of those increases on an average residential customer using 783 therms per month will be $0.33 for 2017, $0.38 for 2018, $0.40 for 2019, and $0.72 for 2020. *Id*. For an average Commercial and

Industrial customer using 8,773 therms, the monthly impact will be $0.96 for 2017, $1.13 for 2018, $1.18 for 2019, and $2.12 for 2020. *Id*.

In approving the EERS as proposed, we are mindful of and do not take lightly the short-term increases in customer rates. When considered in the context of the benefits of increased energy efficiency, participating electric and gas customers will spend less on energy usage and, in the long run, all customers will spend less on energy supply. As suggested by the parties, other benefits could result from increased energy efficiency, but our decision does not rest on that possibility. Instead, our approval of the Settlement Agreement's rate increases is based on a record developed over the course of a year following a year-long investigation by the Staff of EERS potential, both of which were contributed to by numerous experienced and knowledgeable stakeholders and experts. Also, we note in making our decision, the support of the Settlement Agreement by the diverse parties, including the Consumer Advocate, The Way Home, and others. The record and support by parties with diverse interests, along with the customer-protection measures built into the EERS framework, as described below, give us confidence that any short-term rate impacts will be outweighed by the benefits to customers, the grid, and the New Hampshire economy. In addition, we note that our approval of the Settlement Agreement is only the beginning of the EERS; the Commission will oversee the development of the specific EERS programs and their subsequent implementation to ensure that the energy efficiency programs funded by customers are indeed the least-cost resource available to the Joint Utilities' customers.

1. Program Administration

The Joint Utilities have direct relationships with their customers, who may need help and support in making efficiency investment decisions, and the Joint Utilities have direct access to customer consumption data and technical resources in New Hampshire and neighboring jurisdictions. In addition, the Joint Utilities have demonstrated a commitment to energy efficiency and have a history of award-winning management and delivery of the Core programs. They also have infrastructure and market-participant relationships in place to quickly scale up programs to meet increased savings goals. Consequently, at least for the first triennium, the Joint Utilities are a logical choice for the role of administrator within an EERS framework.

2. Savings Targets and Planning Periods

In the last decade, several New Hampshire specific studies have identified energy efficiency savings potential. Although those studies are somewhat dated,[15] based on the record, we find that they provide a reasonable sense of the achievable, cost-effective efficiency savings potential in New Hampshire, for the purpose of approving the EERS framework. *See* Exh. 4 Staff at 15; and Exh. 8 Sustainable Energy Group at 15-16. The short-term savings goals recommended by the Settlement Agreement are reasonably consistent with those studies and also fall within the range of savings recommended by the various parties in this proceeding, who represented diverse interests. In addition, setting a long-term qualitative goal of ultimately achieving all cost-effective efficiency savings as recommended by the Settlement Agreement follows the recommendations of the New Hampshire specific studies and allows flexibility to set that goal in the context of the market conditions that develop over time within the EERS structure.

Consequently, we approve the proposed EERS savings goals for the first triennium of the EERS as a percentage of 2014 statewide delivered sales: 0.80% for electric and 0.70% for gas in 2018; an additional 1.0% for electric and 0.75% for gas in 2019; and an additional 1.3% for electric and 0.80% for gas in 2020. Those statewide savings goals are cumulative and are

[15] GDS Report (January 2009) and the VEIC Report (November 2013)

intended to reach overall savings of 3.1% of electric sales and 2.25% of gas sales, relative to the baseline year of 2014, by the end of 2020. We also approve the recommendation to continue the Core programs in 2017, with adjustments to funding and savings goals as provided in the Settlement Agreement, in order to allow adequate time for careful and thoughtful planning for implementation of the first EERS triennium. Specifically, the 2017 Core-extension savings goals shall be 0.60% of 2014 statewide delivered sales for electric and 0.66% of 2014 statewide delivered sales for gas.

We agree with and approve the Settling Parties' recommendation to use three-year planning periods instead of the two-year periods used in Core. Three years is long enough to afford more stability and continuity in program delivery, which will help customers and other stakeholders plan their efficiency investments, but not so long as to limit the Commission's flexibility to adjust savings targets in response to changes in market conditions or other developments during that time Also, using three-year periods aligns the EERS with industry practice and is consistent with the planning periods used previously for the gas efficiency programs. *See, e.g.*, *Northern Utilities, Inc*., Order No. 24,630 at 7 (June 8, 2006) (order approving a three-year plan refers to the prior three year program cycle).

3. Costs and Funding

The proposed costs of achieving the short-term goals recommended by the Settlement Agreement appear to be just and reasonable as well as consistent with the recent legislative mandate to consider energy efficiency a first-priority supply resource. We take note of the Settling Parties' proposal to increase the low-income program budget. At a time of uncertainty about the future of energy supply in the New England region and consistent with legislative directive in RSA 374-F:3, V (Commission shall "enable residential customers with low incomes to manage and afford essential electricity requirements"), we find this proposal to be appropriate. Moreover, increasing low-income efficiency funding and activities should free up some of the low-income financial assistance also collected through the SBC and LDAC, because those customers' energy consumption will decrease.

While rates may increase slightly for all customers in the short-term in order to recover the costs of an EERS, customer bills will decrease when their energy consumption decreases as well as when the impact of consumption decreases are reflected in reduced grid and power procurement costs. *See, e.g.*, Exh. 2, Sustainable Energy Group Attachment at 2 and at 3-4. While the cost benefit tests ensure benefits to all customers, it is true that those who participate in efficiency programs are likely to benefit most. They will receive immediate benefits from bill reductions, improved comfort, and higher home or business value. Those advantages are in addition to the utility system benefits enjoyed by all customers. In return, however, customer participants must invest time and take full advantage of financial incentives or technical assistance, and they often must pay additional out-of-pocket expenses. Non-participating customers enjoy the benefits from load and system improvements. *See Granite State Electric Company*, Order No. 20,362, 76 NH PUC 820, 823 (1991). In addition, the efficiency programs will reduce emissions and may reduce utility revenue requirements through reduced operation and maintenance (O&M) expenses. Further, the availability of the direct benefits from participation, coupled with broad-based programs, should send a signal to all customers and encourage broad participation in the programs.

The record supports our finding that the EERS, and the energy efficiency market needed to support it, requires stable funding to grow and function optimally. *See* Exh. 3 Joint Utilities Petition at 48; and Exh. 2, Sustainable Energy Group Attachment at 2. The SBC and the LDAC are stable sources of revenue, and using ratepayer funds to achieve the public benefits of cost-effective energy efficiency is just and reasonable. Although the total funding collected under the RGGI program could cover a good portion of the incremental costs associated with EERS' increased savings goals, at this time, access to those funds for energy efficiency is limited by statute. *See* RSA 125-O:23.

Also at this time, private funding is limited and not as stable and reliable as the SBC and LDAC, and private funding alternatives have not been adequately investigated. *See* Exh. 3 Joint Utilities Petition at 6, 48, and 51-52; and Sustainable Energy Group Exh. 2, Attachment at 11-12; Exh. 5 Acadia Center at 7; and Transcript at 83-84 *see also* 2015-2016 Core Plan (DE 14-216) (includes a few new and relatively-new private financing programs). As seen in other jurisdictions, private funding increases following increased public funding of an EERS.[16] We note the Settling Parties' commitment to continue the work started in the Core programs to nurture and expand private funding options. Private funding should continue to be used to the greatest extent possible to fund the EERS programs. We will look to the plan for the first EERS triennium to describe those efforts and any new private funding proposed or under consideration for the future.

The SBC was established by the Legislature as part of electric restructuring. *See* RSA 374-F:4, VIII. The Commission has not increased the SBC since the inception of the Core programs in 2001. *Id*. Failing to increase the funding to support higher savings goals at this time not only fails to provide the Joint Utilities' customers with viable and proven options for energy

[16] Exh. 2 Sustainable Energy Group at 11 "Studies of financing programs have concluded that combining financing with traditional rebates and incentives leverages deeper savings and broader participation" (citations omitted), Exh. 4 Staff at 86. "In some markets program administrators have begun to tap secondary markets and a number of transactions have taken place representing a total volume of $400 million" and at 89 "Observers believe that when these conditions are met, lower cost capital may become available which will result in lower interest rates for customers.")

at least cost, but also fails to capture other benefits for customers. The Commission's oversight, and the requirement that all programs meet a cost-effectiveness test that projects greater benefits than costs over the life of the measures, ensures that the programs and spending of ratepayer funds are just, reasonable, and least cost. Therefore, we approve the proposal to fund the EERS through increases to the SBC and LDAC as proposed in the Settlement Agreement. We note that, when the three-year EERS plans are filed, we will review in advance and approve that spending only to the extent that it is just, reasonable, and least cost.

4. Recovery of Lost Revenues

With increased energy savings comes decreased utility revenues due to standard rate design, which recovers costs through a variable, or consumption-based, rate. The lost revenue adjustment mechanism (LRAM) recommended by the Settlement Agreement enables the Joint Utilities (except NHEC) to recover the portion of their authorized revenue requirement lost due to energy efficiency activities. The LRAM is not designed to increase the revenues recovered by the utilities, and lost revenues are not considered a cost for the purpose of the cost/benefit test used to assess efficiency programs in the Core or within the EERS. Specifically, without the LRAM, or a change in the way rates are designed today, the utilities may lose revenue that the Commission has already determined in the utility's rate case is just and reasonable for them to recover. Consequently, we approve the LRAM as proposed.

Nonetheless, we are mindful that, with an LRAM, the utilities' revenues can increase above their authorized revenue requirements from increased sales, and, for that reason and others, some parties prefer decoupling. This is because decoupling provides a reconciliation to the last-approved revenue requirement (*i.e.*, in the case of a utility collecting more revenue than its last-approved revenue requirement, the utility would be required to prospectively credit customers for any such over-collection). We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before.

5. Performance Incentives

The Commission has used performance incentives successfully in the Core programs to encourage utility investment in energy efficiency. In light of the addition of an LRAM, we agree with the Settling Parties' recommendation to reduce the level of performance incentives available to the Joint Utilities under an EERS. The recommended levels are sufficient to provide a reasonable incentive to pursue exemplary performance in program administration and delivery and to put efficiency investment on an equal footing with other earnings opportunities available to the Joint Utilities.

In addition, the recommended performance incentive level is less likely to provide excessive earnings and is more commensurate with the lower risk of investing in efficiency.

6. Stakeholder Involvement

Involving energy service stakeholders in the development and implementation of the EERS is important, because they are directly connected to the provision of energy and efficiency services. The active participation in the EERS of Settling Parties, who include representatives of the Joint Utilities, Commission Staff, DES, consumer advocates like the OCA and NHLA, efficiency experts and service providers, brings different knowledge, experience, and perspectives. New Hampshire is fortunate to have so many stakeholders who are invested in the success of energy efficiency and the EERS; their contributions and collaboration in this proceeding produced a more robust result. As economy wide involvement in energy efficiency measures will yield the best results, we encourage fuller participation of the New Hampshire business community going forward.

We appreciate the Joint Utilities' access to counterparts and expertise in other jurisdictions that lead the nation in the provision of energy efficiency services and encourage further interactions. To enable the well-informed contribution of the non-utility stakeholders in work required in the future to assure success of the framework we establish today, we approve the Settling Parties recommendations related to the retaining and funding of a planning consultant, an EM&V oversight consultant, and the EM&V studies consultants.

The EESE Board is a collection of diverse energy stakeholders, and its involvement in the EERS planning and implementation, as recommended by the Settling Parties, is appropriate. To fulfill that advisory role, the EESE Board requires technical resources consistent with the Settlement.

7. Evaluation, Measurement and Verification

We approve the EM&V proposals contained within the Settlement Agreement. Rigorous and transparent EM&V is essential to a successful EERS, to ensure that the efficiency programs actually achieve planned savings in a cost-effective manner. The addition of the EESE Board and additional expert resources to the EM&V proposed for the EERS will protect customers through consistent and fair assessment of program performance and cost effectiveness. Moreover, a Technical Resource Manual that meets New Hampshire needs, as proposed by the Settlement, will enable EM&V transparency, consistency, and accuracy.

8. Regulatory Process

We approve the Settling Parties' recommendations for an EERS process, including the pre-filing collaborative preparation of a plan for the first triennium with the assistance of a planning expert. We agree that such a process will likely result in a more efficient and less adversarial adjudicative proceeding following the plan's filing for Commission review and approval. An abbreviated annual plan update process during the trienniums, like the process we currently use for the Core dockets, is appropriate and will enable the stakeholders some flexibility to respond to developments in the energy efficiency market during that time.

In addition, we approve the annual process proposed for setting and reconciling the LRAM as described in the Settlement Agreement and the Joint Utilities EERS proposal. In calculating lost revenue, savings shall be adjusted to account for retirements, the actual timing of efficiency-measure installation, and the results of EM&V studies. Total lost revenues shall be capped at 110 percent of planned annual savings, audited by an independent third party, and recovered through an adjustment to the SBC or LDAC, depending on the utility.

9. Implementation Date

We approve the Settling Parties' recommendation to begin implementation of the EERS on January 1, 2018.[17] We recognize the Settling Parties' significant investment of time and resources during the last two years to reach this point in the development of an EERS framework, and we appreciate their willingness to continue their work to carefully and thoughtfully prepare a specific and detailed plan within that structure.

[17] An implementation date of January 1, 2018 for an EERS complies with the Legislative directive in HB 2 that, "[f]or the biennium ending June 30, 2017, the public utilities commission shall not expend any funding on the implementation of an energy efficiency resource standard without prior approval of the fiscal committee of the general court." N.H. Laws of 2015 ch. 276:223..

10. Beyond Implementation

We appreciate the foresight of the various parties who offered recommendations for the future of the EERS. Nonetheless, we defer any judgment on the merits until such time as specific proposals are presented for our review and approval.

Although not covered in the Settlement Agreement, Integrated Resource Plans are a critical component to the success of an EERS. IRPs are planning studies produced by electric and gas utilities to determine resource needs over a given planning period. The planning period is generally between 10 and 20 years. Methodologies used in the studies vary, but are intended to produce the least-cost, least-risk resource balance. Typically, the utility performs a number of studies as part of an IRP including a customer energy and peak demand forecast. To plan for achieving the EERS savings goals and confirm that its efficiency programs are least cost, the IRP should also include an energy efficiency market potential study and should model the inclusion of energy efficiency on a similar basis to supply-side resources or market purchases. Within six months of this order, Staff and the utilities shall meet to discuss and refine the IRP requirements.

V. CONCLUSION

Our establishment today of Energy Efficiency Resource Standards for electricity and gas is both routine and remarkable. It is routine, as we have long required our utilities to help their customers save money by using less electricity and gas. The State’s 10-year energy strategy, developed under RSA 4-E:1 and crafted with the input of consumer groups, environmental advocacy organizations, utilities, and others, also calls for increased energy efficiency throughout all sectors of the economy. The Core energy efficiency programs have given the utilities 14 years of experience with developing and implementing cost-effective programs and the EERS will build on that foundation.

At the same time, the establishment of an EERS is remarkable as it is based on the setting of savings targets, not dollars spent. It is the product of extensive investigation by Staff and collaboration between and among diverse groups of stakeholders. The framework that they developed together and that we approve in this Order will move the State forward, toward specific annual savings goals to achieve objectives set out in the 10-year State Energy Strategy consistent with Legislative directives.

Energy prices have been the subject of public discussion and debate for many years. The EERS is a significant step toward addressing the business community's concerns about remaining competitive in today's economy. The development of specific, cost-effective programs to implement this framework will require the robust participation of stakeholders, including those in the commercial and industrial sectors. Those who choose to participate in the energy efficiency programs that will be developed to meet the EERS targets will see reduced gas and electric bills, and all utility customers should see reduced costs for electric and gas supply in the long run.

We recognize that low income customers face greater hurdles to investment in energy efficiency than other customer. We have therefore approved increased funding for low income energy efficiency programs as recommended by the settling parties. We agree that these changes are appropriate in order to comply with legislative directives and to reduce energy consumption for those customers who need it most.

Based upon the foregoing, it is hereby

ORDERED, that the Settlement Agreement is approved; and it is

FURTHER ORDERED, that the Joint Utilities, except NHEC, shall include in their future IRPs an energy efficiency market potential study and shall model the inclusion of energy efficiency on a similar basis to supply-side resources or market purchases.

By order of the Public Utilities Commission of New Hampshire this second day of August, 2016.

Martin P. Honigberg Chairman	Robert R. Scott Commissioner	Kathryn M. Bailey Commissioner

Attested by:

Lori A. Davis
Assistant Secretary

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

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Docket #: 15-137-1 Printed: August 01, 2016

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:**
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b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

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EXHIBIT
tabbies
#27A
DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

REBUTTAL TESTIMONY

OF

GREGG H. THERRIEN

January 25, 2018

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I. INTRODUCTION

Q. Please state your name, address, and position.

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. My professional qualifications and experience have been provided in Attachment GHT/DECPL-11 to my Direct Testimony filed April 28, 2017.

Q. Have you testified previously before the New Hampshire Public Utilities Commission ("PUC" or the "Commission")?

A. No, I have not.

Q. Did you participate in the PUC technical sessions in the instant case?

A. Yes. I participated in both the August 24, 2017, and November 1, 2017, technical sessions at the Commission's office.

Q. What is your responsibility in this proceeding?

A. In this proceeding, I am responsible for: (1) designing the Revenue Decoupling Mechanism (direct Decoupling Testimony of Gregg H. Therrien) and (2) together with Company Witness David Simek, developing the rate design (direct Joint Rate Design Testimony of David B. Simek and Gregg H. Therrien) for Liberty Utilities (EnergyNorth Natural Gas Corp.) d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

II. <u>SCOPE OF REBUTTAL TESTIMONY</u>

Q. Please summarize the scope of this rebuttal testimony.

A. In this testimony, I:

1) Reaffirm why full revenue decoupling, inclusive of weather and economic adjustment, is superior to Commission Staff ("Staff") witness Mr. Iqbal's proposed weather-normalized limited Revenue Decoupling Mechanism ("RDM");
2) Respond to Mr. Iqbal's five other proposed changes to the Company's decoupling proposal;
3) Respond to the Office of Consumer Advocate's ("OCA") proposed modifications to the Company's decoupling proposal, including the proposed "real-time" adjustment;
4) Rebut the OCA's position that the RDM should be calculated on a total revenue basis rather than on a per-customer basis;
5) Rebut the OCA witness Dr. Johnson's assertions that decoupling improves earnings;
6) Rebut both Staff and OCA witnesses' recommendation for inclining block rate design and lower customer charges; and
7) Respond to Staff witness Mr. Frink's recommended changes to the Low-Income Discount Program.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

As stated in my Direct Testimony, the decoupling rate design measures that the Company is proposing:

- Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;
- Will comport with the State of New Hampshire's vision in its 2014 State Energy Strategy, which recognized that "[r]ealigning utility incentives to reward utilities for investing in efficiency is a necessary part of any effort to increase efficiency in New Hampshire"; [1]
- Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[2] by producing equitable ratemaking beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals, and enable full acceptance of the energy savings initiatives envisioned in the Settlement Agreement; and
- Will fix a flaw in the traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

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1 New Hampshire 10-Year State Energy Strategy, published by the New Hampshire Office of Energy & Planning September 2014. Executive Summary, page ii.

2 The "Settling Parties" as defined in the Settlement Agreement approved in Docket No. DG 15-137, dated August 2, 2016, include: Commission Staff; Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire d/b/a Eversource Energy; the New Hampshire Electric Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way Home; the Conservation Law Foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development Finance Authority; and TRC Energy Services.

Further, as discussed in detail in this Rebuttal Testimony, I conclude and recommend that:

- Staff's proposed limited decoupling mechanism is not in the best interests of customers as it does not sever the relationship between sales volumes and revenues, thus limiting the effectiveness of decoupling. As a result, Staff's proposal does not maximize the benefits of decoupling envisioned in the EERS Settlement.
- 67 U.S. gas distribution companies have implemented RDMs in 29 different states; decoupling has become the mainstream regulatory framework in support of energy efficiency goals. The majority of these RDMs are constructed the same as the Company's proposal.
- The Company agrees with the OCA that a real-time RDM is better for customers in matching the impact of weather on bills, and is mutually beneficial to customers and the Company's cash flows. The Company does not, however, agree with OCA that a "Total Revenue" RDM is appropriate for EnergyNorth, because the Company has experienced dramatic growth in customers in recent years, which is forecasted to continue. Ignoring the revenue requirement associated with new customer additions is contrary to the Commission's approved natural gas expansion policy, evidenced through the approved Managed Expansion Program "MEP" and associated expansion rates.
- Inclining block delivery rates alone do not send a significant price signal to encourage conservation. This change would undermine long-standing rate design

principles such as cost causation. Further, the Commission should approve the Company's proposal to align Residential Non-Heating and Residential Heating fixed customer charges considering the significant shortfall in these rates compared to the results of the Marginal Cost Study ("MCS")[3].

- The Staff's proposal to modify the Low-Income Discount Program should be deferred. The Company respectfully requests that the Commission reject this change in the instant proceeding and open a separate generic docket to fully evaluate any change (if necessary) to this important program.

Q. How is the remainder of your testimony organized?

A. Section III of this testimony addresses decoupling issues raised by Staff and the OCA, and where appropriate, rebuts assertions made by these Parties. Section IV specifically addresses rate design issues. Section V will address Staff's recommended changes to the Low-Income Program. Finally, Section VI summarizes this rebuttal testimony.

III. DECOUPLING

A. Summary of Staff's Recommendations

Q. Please describe the six modifications to the Company's RDM proposed by Staff.

A. Staff proposed the following six modifications to the Company's RDM proposal:

1) The adjustment should be based on weather normalized revenues.

[3] In the case of Residential rates, the MCS results are approximately three times higher than current monthly customer charges.

2) The adjustment should be performed at the rate class level (instead of at the company level).

3) Expected revenue should be calculated at individual rate class level, not at combined rate class level.

4) Expansion rate customers should be included in the RDM calculation.

5) Annual RDM adjustments should be capped at +/- 2 percent.

6) No mid-period adjustment should be made; if needed, an adjustment could be made at the time of Company's next rate case.4

Q. Please summarize the Company's response to Staff's recommendations.

A. As explained in detail below, the Company strongly disagrees with Staff's recommendation that the RDM adjustments should be based on weather normalized revenues. The Company accepts Staff's recommendation Nos. 2 and 3 related to the method of calculating the RDM accrual and the RDM billing rate. The Company does not oppose Staff's recommendation No. 4 to include expansion rate customers in the RDM, with certain exceptions. EnergyNorth disagrees with Staff's proposals Nos. 5 and 6 to cap the annual RDM adjustment at +/- 2 percent and eliminate the mid-period adjustment.

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[4] Direct Testimony of Al-Azad Iqbal ("Iqbal Testimony") dated November 30, 2017, Bates 000010.

B. Staff's Proposal to Exclude Weather Variation from the RDM

Q. Please explain why you disagree with Staff's recommendation to use weather-normalized revenues in the RDM.

A. There are four main areas of disagreement with Staff's direct testimony. First, I disagree that decoupling should be limited solely to company-funded conservation programs. Second, I will rebut the assertion that that the Company's proposal "also eliminates all risk except the risk of management efficiency." Third, I will clarify and explain that the clear majority of RDMs across the country include weather variation in the RDM true-up calculation, either by using actual revenues per customer or a separately billed Weather Normalization Adjustment ("WNA"). Fourth, I add additional context to Staff's interpretations of past Commission guidance regarding decoupling.

1. Scope of the Company's RDM proposal

Q. Do you agree with Staff's assertion that the Company's proposal "is well beyond the efficiency and conservation related sales reductions"?

A. No, I do not. Staff stated, "The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather etc.) which is well beyond the efficiency and conservation related sales reductions."[5] Staff's proposal limits reconciling changes in sales related to utility-funded conservation programs only, and ignores other energy efficiency and conservation actions customers and other stakeholders take to reduce gas

5 Id., Bates 000011, lines 16 through 16.

consumption. In my direct testimony I cite five contributors to declining use per customer:

1) Utility-sponsored Energy Efficiency ("EE")/Demand-Side Management programs;
2) Customer self-funded conservation measures;
3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to increases in natural gas prices and/other economic and demographic factors; and
5) A warmer normal weather trend.[6]

Referring to the above list, items 1), 2), and 3) are unambiguously directly related to energy efficiency, and 4) customer price responsiveness, is (short term reversible) conservation-related when customers are responding to price increases. Item 5) is a clear trend that reduces customer usage. Staff's recommendations focus entirely on contributor 1).

Q. Does the OCA support a decoupling mechanism that encompasses all contributors to the variation in sales?

A. Yes. Although the testimony of Dr. Johnson recommended two modifications to the Company's proposal that I will address later in this testimony, he did not propose to eliminate the impact of weather, or any other variable that contributes to the consumption of gas volumes. In his testimony Dr. Johnson wrote:

[6] Direct Testimony of Gregg H. Therrien ("Therrien Testimony"), Bates 305.

> **Q. Is the proposed decoupling mechanism an improvement over the existing LRAM?**
> A. Yes. It does a better job of removing the disincentive for EnergyNorth to encourage energy conservation, while eliminating the bias in favor of programs and initiatives included in the LRAM.[7]

Dr. Johnson also asserted that:

> Decoupling achieves a broader, more fundamental shift in incentives, because revenues become largely impervious to improvements in energy efficiency – including improvements resulting from tightened building codes, increased appliance standards, technology improvements, heightened awareness of greenhouse gas emissions, and other factors. This broader scope is significant, because EnergyNorth can potentially influence the decisions by customers and the companies that construct new buildings concerning what insulation they install, what appliances they purchase, and what type of energy they use. Currently, EnergyNorth has an incentive to steer customers into the programs and initiatives included in the LRAM, rather than finding other ways to reduce their energy usage that are not tied to those specific programs.[8]

Dr. Johnson's assertions are instructive as to how the Company, together with supportive Commission policy, can enhance energy efficiency. In this regard, full decoupling is the means to this broader scope without penalizing the Company.

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[7] Direct Testimony of Ben Johnson, PH.D. ("Johnson Testimony"), dated November 30, 2017, Bates 9, line 20 through Bates 10, line 1.
[8] Id., Bates 000007, lines 7-17.

2. Business Risks

Q. Please describe Staff's assertions concerning the effect that an RDM would have on EnergyNorth's business risks.

A. Staff stated, "The Commission was also concerned with the potential for risk shifting via decoupling. The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather, etc.) which is well beyond the efficiency and conservation related sales reductions. It also eliminates *all risk* except the risk of management efficiency."[9] *(Emphasis added).*

Q. Does decoupling eliminate all risks except "management efficiency"?

A. No, it does not. Decoupling does not eliminate other, very real risks that gas utilities face, such as increased competition, regulatory risks, economic risks that affect the cost to serve (e.g., inflation), etc. These other exogenous risks, which are beyond the reasonable definition of "management efficiency," are not addressed through decoupling.

3. Weather Normalization and RDMs

Q. Is it common for RDMs to exclude weather from the calculation?

A. No. In fact, only three of the sixty-seven utilities with an RDM in the United States exclude the impact of weather in their RDM calculation. These include utilities in Colorado, Washington State, and Wyoming. Twenty utilities have separate WNA rate

9 Iqbal Testimony, Bates 000011 lines 13-17.

adjustments that complement their RDM, an alternative to including the impact of weather explicitly in the RDM. This is shown here:

Table 1: RDM Calculation Methodologies in the U.S.

Calculation:	Revenue Per Customer (RPC)			Total Revenue			PBR	
State	RDM using Actual Weather	RDM using normal weather and a separate WNA	RDM using normal weather and no WNA	RDM using Actual Weather	RDM using normal weather and a separate WNA	RDM using normal weather and no WNA	PBR (Includes Weather)	Total
AR	1				2			3
AZ		1						1
CA				1			3	4
CO			1					1
CT				1				1
GA							1	1
ID				1				1
IL	2			1				3
IN				2	1			3
LA					1			1
MA	6							6
MD	4			1				5
MI	1							1
MN	1			1				2
MS					1			1
NC	1			1				2
NJ		2						2
NV	1							1
NY	2	7		1	1			11
OR	1	1		1				3
RI	1							1
SC							1	1
TN		1						1
UT		1						1
VA	3							3
VT							1	1
WA	2					1		3
WI	1							1
WY		1	1					2
Grand Total	27	14	2	11	6	1	6	67

As this table shows, almost all LDCs with an RDM also have a mechanism to reconcile for weather. Including a weather reconciliation in the RDM is the norm, not the exception.

4. Past Commission Orders

Q. What is Staff's interpretation of Commission policy regarding decoupling?

A. Staff's interpretation of Commission policy is that a limited decoupling mechanism is the Commission's preferred approach. Staff relied primarily on Docket No. DE 07-064, which pre-dates the EERS Settlement by nearly a decade, and was opened specifically to investigate energy efficiency rate mechanisms.[10] Although Docket No. DE 07-064 did discuss decoupling in the context of overall rate design, and contains high-level guidance regarding cost causation and the impact of rate design changes on certain rate classes,[11] the Order Resolving the Investigation is not a prescriptive document for implementing decoupling. Rather, the investigation set out to answer the following four questions:

1) whether existing rate treatment poses an obstacle to investment in energy efficiency;
2) whether a different rate treatment would promote such investment;
3) whether these issues should be pursued further in this docket, through utility-specific rate cases, as part of a rulemaking, or through some other procedure; and
4) whether decoupling constitutes an alternative form of regulation under RSA 374:3-a. Order No. 24,934 at 4 (January 16, 2009) ("the 2009 Order").

In the 2009 Order, the Commission concluded, "We find, therefore, that the best approach to implementing such rate mechanisms is on a company-by-company basis in the context

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10 "On May 14, 2007, an order of notice was issued commencing this investigation into the merits of instituting, for electric utilities, appropriate rate mechanisms that would have the effect of removing obstacles to, and encouraging investment in, energy efficiency." Order No. 24,934 (January 16, 2009).

11 Iqbal Testimony, at Bates 000008.

of an examination of company specific costs and revenues inasmuch as each utility has a unique service territory and customer mix as well as company specific operating costs and rate base investment." 2009 Order at 19. Nowhere in that Order does the Commission state its preferred decoupling model. On pages 20 through 22 of the 2009 Order, the Commission did discuss "Rate Mechanism Options" including "Reconciling Rate Adjustments" (decoupling), but did not prescribe, or even suggest, that one option is superior to another. Rather, the Order states "*Regardless of the model used*, it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking." (Emphasis added.)

Q. Did the EERS Settlement address decoupling?

A. Yes, in part. My Direct Testimony regarding decoupling described the key agreements regarding energy efficiency programs and related rate mechanisms for utilities in New Hampshire:

1) Extends the Core programs;

2) Requires implementation of a LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);

3) Contemplates the subsequent implementation of a decoupling mechanism to replace the LRAM;

4) Will implement the EERS commencing January 1, 2018;

5) Retains the Performance Incentive, with modifications;

6) Increases the low-income share of the overall energy efficiency budget; and

7) Includes other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (August 2, 2016).[12]

Q. Please summarize the sections of the EERS Settlement that pertain to LRAM and decoupling.

A. Section II B. of the EERS Settlement, "Lost Revenue Adjustment Mechanism and Decoupling" codified the agreement among the Settling Parties as to when the LRAM must be implemented and when utilities may, in the context of a general rate case, propose a decoupling mechanism. The calculation of the LRAM is very explicit in the EERS Settlement – covering approximately two pages of the document. In contrast, decoupling is discussed in more general terms and consumes only one-half page in the EERS Settlement.

The EERS Settlement states:

> The Settling Parties agree that the LRAM for each utility will cease when a new decoupling mechanism, or another mechanism as an alternative to the LRAM, is implemented. The Settling Parties further agree that each of the Utilities shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM, in its next distribution rate case following the first triennium of the EERS, 20l8-2020. This provision does not, and is not intended to, prevent or preclude any of the Utilities from

12 Therrien Testimony, Bates 299.

> seeking approval of such mechanism prior to the end of the first triennium, but the Settling Parties acknowledge and agree that any utility seeking such approval shall do so in the context of a distribution rate case, consistent with the Commission's guidance in Order No. 24,934 (January 16, 2009). The Settling Parties agree that the Commission's approval of the Settlement Agreement does not in any way restrict the Commission from investigating or implementing decoupling, or another mechanism as an alternative to the LRAM, at any time.[13]

Q. Does the EERS Settlement address weather normalization or any aspect of how an RDM should be constructed?

A. No. The above excerpt is the entire content regarding decoupling in the EERS Settlement.

Q. Did the Commission approve the EERS Settlement?

A. Yes. The Commission approved the EERS Settlement in Order 25,932 (August 2, 2016) (the "2016 Order"). In the 2016 Order, the Commission first required utilities to implement an LRAM effective January 1, 2017, and recognized that some of the Settling Parties preferred decoupling. The 2016 Order states:

> We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism *as an alternate to the LRAM* in their first distribution rate cases after the first EERS triennium, if not before (*emphasis added).* [14]

13 EERS Settlement Agreement, page 5-6.
14 Order No. 25,932 (August 2, 2016), at 60.

Q. What can be concluded from the Commission's 2009 Order and 2016 Order regarding decoupling?

A. The 2016 Order clearly articulated the Commission's requirement for utilities to seek approval of something other than an LRAM. As with the 2009 Order, the Commission did not prescribe, endorse, or articulate any specific decoupling methodology, only that utilities should propose an RDM in the context of a general rate case.

C. Staff's remaining five recommended changes to the Company's proposed RDM

1. Staff Recommendations 2, 3, and 4.

Q. Please describe the second and third Staff recommendations to perform the RDM calculation at the rate class level, and the Company's response to Staff recommendations.

A. Staff's second recommendation is that the RDM adjustment should be performed at the rate class level (instead of the proposed RDM Rate Groups).[15] Staff's third recommendation is that expected RDM revenues should be calculated at the individual rate class level, not at combined rate class level.

The Company does not object to calculating the RDM adjustment (accrual) at the rate class level. Further, our understanding of Staff's testimony is that the resulting variances, at the rate class level, will be summed for the Commercial and Industrial ("C&I") classes for purposes of determining the RDM rate adjustment to be applied to customers' bills. Staff did not provide a recommendation as to whether Residential Non-Heating customers

[15] Therrien Testimony, Table 8: RDM Customer Groups, Bates 320.

should receive a separate billing rate from Residential Heating customers under his proposed modification. Staff did, however, tie its recommendation to energy efficiency program "sectors," which combines Residential Non-Heating and Heating together. Using that definition, the Company assumes Staff is suggesting only two separate RDM billing adjustments – one for Residential and one for C&I. Assuming my understanding is correct, the Company does not object to these two recommended changes.

Q. Please explain Staff's fourth recommended change to the Company's RDM Proposal.

A. Staff recommended that customers receiving service under the MEP tariffs also be subject to decoupling. Staff believes RPC for MEP customers should be included in the rate class revenue calculation after the MEP premium is separated.[16]

Q. Does the Company object to this recommendation?

A. No, it does not provided that the RDM rate for MEP customer is the same as the corresponding rate for all other customers in the class.

2. Staff Recommendations 5 and 6.

Q. Does the Company agree with Staff's fifth recommendation to change the +/- 5% cap to a +/- 2% cap?

A. No, the Company's proposed +/- 5% cap should not be changed. The Company's proposal to include weather in the RDM requires a larger cap bandwidth than +/- 2%.

[16] Iqbal Testimony, Bates 000001, lines 18-19.

Otherwise, large deferrals may occur resulting in a larger collection or refund in a subsequent period.

Q. Does the Company agree with the elimination of the mid-term adjustment?

A. No, because the Company's proposal includes the effects of weather. Staff's rationale for proposing elimination of the bi-annual adjustments in favor of a singular annual adjustment is tied to its recommendation to exclude weather from the RDM calculation. The Company continues to advocate for weather-related variances be included in the RDM. Therefore, we continue to advocate for mid-term adjustments.

D. <u>Energy Efficiency ("EE") Performance Goals</u>

Q. Please summarize Staff's recommendation regarding EE goals and decoupling.

A. Staff introduced another proposed decoupling restriction tied to obtaining EE goals. Staff proposed that, "If the Company does not meet its EE goals, there should be some restriction in decoupling adjustment because the logical conclusion is that the decoupling adjustment was attributed to something other than EE."[17] To summarize, Staff recommended that if the RDM calculation yields a charge in excess of the cap (presumably their 2% recommended cap) and EnergyNorth does not meet its EE goals, then "the Company would be required to demonstrate that its EE efforts were the primary factor in reducing its energy sales in order for any amount above the decoupling cap to be

[17] Iqbal Testimony, Bates 000013, lines 10-12.

carried forward for recovery in a subsequent year."[18] A credit calculation would not be subject to such a review.

Q. Do you agree with Staff's recommended asymmetrical cap restriction?

A. No, I do not. Limiting the decoupling calculation to exclude any sales variation "other than EE" will penalize the Company for expanding its EE efforts beyond company-funded programs. I have presented in my Direct Testimony, and in this rebuttal testimony (Section III. B. above), that decoupling is intended to completely sever the link between utility revenues and sales units. Otherwise, the signal to the Company is something less than desired – because sales volumes will still matter.

E. The Company's response to the OCA's proposed RDM modifications

1. Introduction

Q. Please summarize the major points of OCA Witness Dr. Johnson regarding decoupling.

A. Dr. Johnson, on behalf of the OCA, proposes two modifications to the Company's RDM proposal. First, he proposes a "real time" decoupling adjustment for the weather-related portion only, and 2) recommends that the RDM be calculated on a "Total Revenues" basis as opposed to RPC.

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[18] Ibid, lines 14-17.

Q. Did the OCA make other assertions regarding decoupling?

A. Yes, he did. I will address, and rebut where appropriate, assertions made by the OCA regarding decoupling's association with Company earnings, rate base, and capital investments and depreciation. I will also address the OCA recommendation to disallow potential Computer Information System ("CIS") modification costs from rates.

2. OCA's recommended RDM changes

a. "real-time" adjustments

Q. Please summarize OCA's first recommendation regarding a "real-time" decoupling adjustment.

A. The OCA recommended that the Company separate the weather-related portion of the RDM from the remainder of the calculation. Specifically, the OCA called for a customer-by-customer calculation of the impact of weather, and bill that amount (based on the customer's actual volumetric delivery charge unit rate) in the month in which the weather variance occurred. In doing so, the OCA submitted that "it will help smooth out bill fluctuations, making cash flows smoother and more predictable for both the Company and its customers."[19] The OCA also provided examples of how this real-time adjustment would work, under both colder-than-normal and warmer-than-normal weather conditions, making the point that the real-time adjustment will match the variation in weather and provide synchronized, real-time revenue stabilization to customers and the Company.[20]

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[19] Johnson Testimony, Bates 16, lines 9-11.
[20] Id., Bates 16-18.

Q. How would the portion of the decoupling adjustment that is not weather-related be treated?

A. The calculation of the RDM would be calculated essentially the same as proposed by the Company (I will address the OCA's "Total Revenue" recommendation later in this testimony). The total difference between Actual and Target revenues will be refunded or collected in a subsequent period. The OCA noted that this adjustment would likely be considerably smaller than an RDM that does not adjust for the weather component real-time.[21]

Q. What reservations does the Company have regarding separating the weather component of the RDM on a real-time basis?

A. "Real time" weather adjustment, referred to as a Weather Normalization Adjustment or "WNA," requires that the dollar impact of the difference between actual and normal usage be calculated for each customer bill, at the time the bill is rendered. This requires extensive programming in the billing system, and significant additional training of call center personnel charged with explaining the WNA to customers.

The OCA stated that "customers are more likely to understand and accept the mechanism if the portion that deals with weather-related fluctuations is separated from the portion that deals with energy conservation and other factors influencing usage."[22] Although I agree that matching the weather-related portion of the mechanism with the customer's bill is a

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21 Id., Bates 15.
22 Id., Bates 19, lines 2-4.

reasonable concept, I am not convinced that it is easier to explain than an annual true-up. For example, the Company's proposed RDM results in a single billing rate adjustment to be applied each month of the applicable season. It is easy to explain that a charge occurs because last winter's weather was warmer than normal. The issue I have with real-time application is that the formula is complex and difficult to explain, and contrary to the OCA's assertions, I have experienced first-hand the difficulty in explaining this adjustment on a customer's bill. This difficulty stems from the following factors:

1) EnergyNorth has twenty billing cycles in a billing month, and they span approximately sixty days (i.e., cycle 1 customers are billed from the beginning of the prior month to the beginning of the current month, while the last billing cycle closely matches the calendar month in which it is billed). Call Center employees will need to consult the actual and normal degree days for the applicable billing cycle to explain the variances.
2) Call Center representatives will also need to understand a complex formula used to derive the actual charge that is on each customer's bill. This includes understanding base usage, heat usage, degree days, and the blended volumetric rate applied to the usage adjustment.
3) If there was a reason for the customer's bill to be adjusted (e.g., cancelled then rebilled), the complexity of the bill makes auditing of the WNA charge extremely difficult.

4) From a rate administration perspective, rate changes result in a month of pro-rated bills. The WNA adds complexity to the necessary audit of distribution rate changes.

5) Reporting requirements (both to internal utility management and to state commissions) is likely to increase and add complexity.

In contrast, the Company's proposed RDM is easy to understand, calculate, and audit, and should have minimal reporting requirements.

Q. Please describe the Company's concerns with the OCA's proposed RDM.

A. The concern with the OCA's proposal is that it is unnecessarily complex. Forty-four of the sixty-seven U.S. companies with an RDM use the more straightforward approach to including weather variances that the Company has proposed. Although twenty utilities do employ the combination of a WNA and decoupling, it is likely the result of already having a WNA in place prior to introducing decoupling. Despite its complexity, it is still superior compared to an RDM that excludes the impact of weather.

Q. Do the above concerns imply that the Company is unwilling to employ RDM with a real-time adjustment?

A. No. The OCA's proposed real-time RDM component does have benefits for both customers and the Company, and, most importantly, recognizes that all contributors to sales variation impact the efficacy of energy conservation. A real-time RDM is superior to Staff's proposal that does not include weather variation in the calculation. The OCA's proposal is a true decoupling mechanism, and the Company appreciates the OCA's understanding of, and dedication to, an RDM that truly breaks the link between utility revenues and gas usage.

Q. If a real-time RDM were implemented, how would the Company address the difficulties that you describe above?

A. If a real-time RDM were implemented, the Company would work with both the OCA and Staff to develop communications materials for customers, and to address the administrative and reporting requirements associated with a real-time RDM.

b. "Total Revenue" RDM

Q. Please describe the OCA's proposal to utilize a "Total Revenue" approach to RDM.

A. A Total Revenue approach is exactly that – total revenues are "locked in" as a result of the Commission's final determination in the rate case and these revenues then become the "Target" revenues utilized in subsequent RDM filings, comparing Actual total revenues to this Target. The primary advantage of a Total Revenue approach lies in its simplicity and predictability. Simply put, revenues do not change year-over-year. The primary disadvantage, which the OCA recognized, is that it can be a deterrent to growth. That is why more U.S. LDCs employ an RPC decoupling mechanism rather than a Total Revenue approach. LDCs are in the business of adding new customers to the distribution system, either through conversion from an alternative fuel within its existing system footprint, or from expanding the system to reach new customers. Total Revenue RDMs do not encourage growth (and, in fact, discourage growth) because revenues received from new customer additions are in effect "refunded" to existing customers through the RDM, leaving the utility to fund growth investments without incremental revenue to support those investments.

Q. Please explain why utility retention of revenues from new customers is important.

A. Most U.S. commissions, like New Hampshire, encourage their LDCs to expand, providing greater fuel choice to the residents of their respective states. Further, regulators want to protect against existing customers subsidizing uneconomical growth. New customer revenues help cover the cost of new investments without adding pressure to seek rate relief that results from a growing rate base. If these new customer revenues are not retained, but returned to existing customers through a Total Revenue RDM, then, all else being equal, the utility will seek rate relief sooner than if those revenues were retained.

Q. Does the New Hampshire Commission encourage growth?

A. Yes, it does. The Commission has approved the Managed Expansion Program ("MEP"), which also includes separate rate schedules with premium distribution rates. These premium rates help fund more aggressive system expansion than that which could otherwise be supported through standard delivery rates. The Commission recognizes that increased sales reduces the fixed costs borne by all other customers by spreading those costs over a greater volume of sales.

Q. Are there other related comments made by the OCA regarding funding of growth investment?

A. Yes. The OCA suggests depreciation between rate cases can fund growth. He wrote:

> There is no assurance that the increase in total revenues that occur under the per-customer approach is fully needed, or that the resulting revenue growth will match any corresponding increase in the revenue requirement. It is also important to keep in mind that EnergyNorth has cash flows provided by depreciation and retained earnings that can be used to support new customer additions. If its capital additions exceed depreciation, and as a result its rate base increases (rather than decreases as depreciation accumulates), it will have the opportunity to recover the associated costs after they are reviewed and approved in a rate case.[23]

Dr. Johnson's argument that depreciation is sufficient to fund growth investments is unfounded. His argument relied on system-wide depreciation and retained earnings to fund new customer investments. I agree these are sources of funds, but only depreciation, to the extent it reduces rate base, helps alleviate revenue requirement growth. Depreciation is often used to fund *non-revenue generating capital investment*, such as reliability investments (e.g., improvements to LNG facilities, gate stations, etc.), as well as ongoing capital needs (e.g., fleet vehicles, equipment, information technology, metering, etc.).

Q. Do new customer additions require incremental investment?

A. Yes, any new customer addition to the system will require at least a service line and meter. In many cases, such as MEP projects, new main is also required to serve new customers. If the OCA's recommendation to include new customer revenues in its proposed Total Revenue RDM is implemented, then the Company will incur a shortfall in revenue

[23] Id., Bates 13, lines 4-11.

requirements associated with this new investment, which may have a dampening effect on growth.

Q. Does the OCA offer a solution to this problem?

A. Yes, in part. The OCA proposed an alternative: exclude expansion customers from the RDM.[24] This is the same solution the Company proposed in its Direct Testimony.[25] If the Commission wishes to include expansion customers in the RDM, it should consider Staff's fourth RDM recommendation, which would exclude the 30% distribution rate premium revenues from the RDM calculations, but include the remaining (base level) revenues from MED customers in the RDM calculations. However, the expansion rate is only applicable to those areas where customers could not be served under standard rates (absent a high CIAC by those customers). The OCA's proposal did not address the majority of the Company's growth, which is under standard rates. Additional revenue from that growth would still be refunded to customers through the OCA's proposed RDM.

Q. Please summarize the Company's position regarding the OCA's Total Revenue RDM approach.

A. The Total Revenue approach is flawed insofar as conflicts with Commission policy to encourage natural gas expansion. For gas utilities, retaining growth-related revenues to fund the incremental investment is critical, particularly during a concerted effort to expand the system. Additionally, RPC RDMs are more common than Total Revenue RDMs (s*ee*

[24] Id, Bates 14, lines 9-19.
[25] Therrien Testimony, Bates 323, line 3 through Bates 324, line 2.

Table 1). For these reasons, the Company reiterates its preference for a revenue-per-customer RDM.

3. CIS Upgrade for Real-Time RDM

Q. Please comment on the OCA's recommendation to disallow any incremental costs associated with CIS investments necessary to implement their proposed real-time decoupling proposal.

A. It is inconsistent for the OCA to advocate for disallowance of a cost that supports the OCA's real-time RDM proposal, a cost that is not necessary to implement the Company's proposal. If the OCA's real-time RDM proposal were to be approved, the related costs should be considered legitimate business expenses and allowed for recovery. The Commission Staff audits expenses and investments made by the Company as part of rate reviews. There is no need to predetermine that the CIS changes necessary to implement a real-time RDM should be disallowed prior to the project commencing.

IV. RATE DESIGN

A. Response to Staff's Recommendations

Q. Please summarize Staff's recommended head and tail block delivery rate changes.

A. Staff recommended two changes:

1) Set the rates for both head and tail block at the same level; and

2) Allocate any decoupling adjustment to the head or tail blocks based on whether it is a surcharge or refund. Refunds would be allocated to head block and surcharges

would be collected from the tail block for the residential sector and high winter use C&I customers.[26]

Q. Please explain the Company's response to Staff's first recommendation, that head and tail blocks should be equalized.

A. Staff's proposed change does not significantly impact customers' bills to warrant objection considering the Company's decoupling and fixed customer charge rate proposals.

Q. Does the Company object to Staff's second recommendation?

A. Yes. Staff proposed an asymmetrical application of the decoupling adjustment between the head and tail block volumetric delivery rates. Justification for this proposal is two-fold. First, Staff claimed that, "It will provide a proper price signal to the customers to encourage energy conservation."[27] Second, "This approach would also benefit lower consumption households that could tend to include be lower income households with smaller homes and less energy use compared to higher income households. Low use households, on average, have relatively little or no consumption in the tail block and thus would see little or no rate increase from decoupling."[28]

Staff's proposal is unfair to higher use customers that have much of their monthly usage in the tail block. Their proposal unfairly allocates RDM under recoveries to higher use

[26] Iqbal Testimony, Bates 000016, lines 19-22.
[27] Id., Bates 000017, lines 14-15.
[28] Id., Bates 000017, lines 15-19.

customers and unfairly allocates RDM over recoveries to lower use customers. Staff's assertion that their proposal further encourages conservation through a price signal that charges a higher rate on higher consumption is unsupported.

Q. Does Staff's proposal have the potential for under-recovery?

A. Yes. Under Staff's proposal, many low use customers would presumably not pay a decoupling charge because their usage would be low enough as to not fall into the tail block. This creates the potential for a shortfall in recovery that must be deferred until the next winter season.

Q. Does Staff's proposal alleviate concerns regarding undue rate impacts to small rate classes?

A. No. Staff argued that "This addresses the stated concern of the Commission that any decoupling proposal to change the rate design needs to consider the impact on small rate classes to ensure that such classes are not unduly impacted by such changes", and "It also reduces the volatility of gas bills for low use customers."[29] Using data from my direct testimony, the highest winter period decoupling adjustment over the past five years would have been $0.0180 per therm.[30] To put this in perspective, a Low Income Residential Heating customer on the R-4 rate using 105 therms in January has a total bill of $105.46 at current rates.[31] If decoupling were in place in January 2017, this customer would have

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29 Id., Bates 000017, line 19 through Bates 000018, line 2.

30 Therrien Testimony, Bates 328, Table 10, Winter 2016-2017 rate per therm.

31 Direct Testimony of David B. Simek and Gregg H.Therrien ("Simek/Therrien Testimony"), April 28, 2017, , Attachment RATES-8, page 3 of 16 (Bates 257), line 203.

been charged an additional $1.89, which would have represented a 1.8% increase to their bill. I do not believe that a $1.89 charge would "unduly impact" low use customers or create "volatility" in their gas bills. If Staff's recommendation to eliminate the difference between head and tail block unit rates is implemented, low use customers rates would go down because current rates have a higher head block rate than the tail block. Using Staff's premise that low use customers are less likely to experience usage in the tail block, their overall bill will likely go down more than any increase from a decoupling charge.

B. <u>Response to the OCA's Recommendations</u>

Q. Please summarize your understanding of the OCA's proposed rate design.

A. The OCA seeks to reduce fixed customer charges and increase volumetric charges, particularly in the tail block.

Q. What justifications does the OCA use to rationalize reducing customer charges?

A. The OCA began its argument for lowering fixed charges not by introducing evidence to support such an action, but rather through criticizing the Company's logic for requesting increases. These criticisms include how the flow of the rate design Exhibit-5 works, which is a mathematical schedule that logically reconciles allocated class revenue requirements by first subtracting out fixed cost recovery then volumetric recovery. The OCA also makes the following criticisms and recommendations related to the Company's proposed customer charges: (1) the Company's estimate of marginal customer-related costs is flawed and therefore, the Company's proposed customer charges, which are informed by the estimated customer-related costs is also flawed; (2) greater consideration should be given to increasing volumetric rates, to advance state conservation goals, which necessarily requires lowering fixed charges; and (3) lastly, the OCA attempted to dismiss long-standing cost causation principles used in utility rate design.

Q. Are the Company's rate design workpapers biased towards increasing fixed customer charges?

A. No, the rate design workpapers are mathematical, and follow a logical sequence to prove proposed rates produce proposed revenues (i.e. "revenue proof"). The OCA asserted that "The Company made a priority to increase its customer charges (the fixed monthly rate that applies regardless of how much or how little gas the customer uses). This priority is apparent from the workpapers it used to develop the proposed rate design, and is alluded to on pages 16-17 of the joint testimony of Simek and Therrien."[32] His claim that the construct of the Company's workpapers prioritize increased customer charges is unsupported and no alternative calculation is presented.

Q. Is the Company's rate design approach consistent with past precedent?

A. Yes, the Company's recommended fixed cost rates are in line with prior proposals, which have also relied on the results of the MCS to guide its rate design recommendations. Further, as stated in the Simek/Therrien Testimony, "The proposed rates represent a balancing of the principles of appropriate rate design which include efficiency, simplicity, continuity of rates, fairness between rate classes, and corporate earning stability."[33] These

32 Johnson Testimony, Bates 24, lines 19 – 22.
33 Simek/Therrien Testimony, Bates 205.

are long-standing principles that have guided utility ratemaking for decades.[34] The OCA suggested that employing these principles undermines the Company's proposal to increase fixed charges, citing our direct testimony at page 17as follows:

> To determine the appropriate level of customer charges for each class, we considered: (1) the marginal customer costs resulting from the marginal cost study; (2) rate continuity; and (3) customer impacts.

In response to this stated approach the OCA stated, "The second and third items just mentioned did not support increasing the customer charges; rather, they ameliorated the extremely large increases that would be needed to move these rates all the way to the Company's estimate of marginal cost."[35] Interpreting this passage, it appears that Dr. Johnson believes that employing rate continuity and customer bill impacts undermines the Company's proposal. This is contrary to the rate design principles discussed above.

Q. Does the Company have any other comments regarding the efficacy of raising the tail block distribution rates?

A. Yes. First, the Company notes that the tail block currently represents approximately 3.3% of the total bill.[36] The commodity portion is 54.7%.[37] Raising the tail block rate will have only a minimal price signal compared to the price of the commodity, which is subject to change every month, and can change significantly. Second, using OCA's proposed rates,

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[34] *See* "Principles of Public Utility Rates", Second Edition, by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen. Public Utility Reports, Inc. 1988.

[35] Johnson Testimony, Bates 25, lines 7-9.

[36] Using January 2016 Residential Heating (R-3) as a proxy. See Simek/Therrien Testimony Attachment RATES-8 page 2 of 16 (Bates 256), line 112/132.

[37] Ibid, line 124/132.

[38] bill impacts for larger users are considerably higher compared to the Company's proposal.

Q. Has the Commission considered cost causation when designing utility rates?

A. Yes. The Commission has not only recognized, but has been progressive in recognizing cost causation and has designed rates with this important principle in mind. The OCA referred to an American Gas Association (AGA) survey that indicates that the Company's fixed customer charges are high compared to other gas utilities. This comparison should not deter the Commission from designing rates based on cost causation principles. The costs of providing utility service are largely fixed, and having a customer charge that sends the price signal that utility service is available regardless of how much gas is consumed is appropriate. The Company's Marginal Cost Study indicates Residential class customer costs in excess of $60 per month, well above the Company's proposed monthly customer charge for rates R-1 and R-3.

Q. Should public policy considerations play a role in rate design?

A. Yes. However, the rate design principles cited above should not be ignored. If the Commission wishes to move toward more volumetrically-weighted rates, it should do so only after assessing the impact on the full range of customers' bills, and respecting the other long-standing rate design principles of rate gradualism and simplicity.

[38] Johnson Testimony, Bates 107.

V. CHANGES TO THE LOW-INCOME PROGRAM

Q. Please summarize your understanding of Staff's proposed modifications to the Residential Low-Income Assistance Program ("RLIAP").

A. Staff has proposed to modify the existing RLIAP in two phases. First, the RLIAP is proposed to be reduced from a 60% reduction in delivery-only charges to 25% of total projected gas costs. Second, in year 2 the rate would decline to 20% of projected gas costs. As is currently done, the proposed RLIAP rate should be included in the LDAC rate contained in EnergyNorth's winter COG filing, and the approved LDAC rate would be effective for November 1 through October 31, with savings to be calculated on the projected total bill for an average residential heating customer for the 12 months commencing November 1 of that year.[39] Although not specifically addressed, the Company assumes that base delivery rates in the instant case would continue to include an adjustment to the firm delivery rate classes for the projected rate year RLIAP projected dollar amount, and any differences reconciled through the COG annual filing and billed through the LDAC.

Q. Does the Company agree with this proposal?

A. The Company does not take a position with this proposal. However, the Company questions the timing of this proposal and use of the instant proceeding to review it.

[39] Direct Testimony of Stephen P. Frink, November 30, 2017 Bates 27.

Q. Please explain.

A. The Company believes that this topic is best adjudicated through a generic proceeding, which would continue past precedent established in the original pilot program in Docket No. 05-076, see Order No. 24,508 (September 1, 2005), and subsequent program revisions in Docket No. DG 06-120, see Order No. 24,669 (September 22, 2006). In addition, Staff's proposal implicates other rate components that are not part of this rate case. Further, this issue was not included in the Commission's Order of Notice in this proceeding[40] which may have precluded other interested entities from intervening in this case. For these reasons, the Company respectfully recommends that the Commission open a separate generic proceeding if this proposal is going to be considered.

Q. How would rejecting this proposal change the instant case?

A. The Company's filing in the instant case would not be changed. Further, any changes that may arise from a generic RLIAP proceeding could be implemented through the annual COG filing, and rates adjusted through the LDAC. It is not necessary to implement a change in the RLIAP in the context of a general rate case.

[40] Order No. 26,015 (May 8, 2017) "Order Suspending Proposed Tariff and Scheduling Prehearing Conference and Temporary Rate Hearing".

VI. SUMMARY

Q. Please summarize this rebuttal testimony.

A. EnergyNorth appreciates the inputs received from Staff's witness Mr. Iqbal and OCA witness Dr. Johnson regarding decoupling and rate design. However, some aspects of their respective proposals should be rejected. Specifically:

1) **Staff's recommendation to weather normalize sales prior to performing the RDM adjustment should be rejected.** Staff's decoupling proposal is nothing more than a continuation of the LRAM and does not sever the link between Company sales volumes and revenues, which undermines the potential for greater energy efficiency savings present in the Company's and in the OCA's decoupling proposals.

2) **The Company agrees with the OCA's proposal for a "real-time" RDM, but disagrees with calculating decoupling on a Total Revenue basis.** EnergyNorth is a natural gas utility in growth mode, and the incremental revenues from new customer additions should be retained between rate cases to fund growth investments. Any incremental computer enhancement costs to implement this proposal should not be rejected, as recommended by the OCA..

3) **Staff and the OCA's inclining block rate proposals should be rejected.** The Commission's long-standing practice of designing customer rates based on cost causation should not be discarded as a result of implementing the RDM. As detailed above, gas commodity charges represent the largest component of the bill

and send the most impactful price signal. Further, the Company's proposed fixed customer charges should be approved, as supported through the MCS.

4) Staff's proposal to change the RLIAP should be addressed in a properly noticed generic proceeding.

Q. Does this complete your testimony?

A. Yes, it does.

NHPUC NO. 9 - GAS

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. D/B/A

LIBERTY UTILITIES

SUPERSEDING NHPUC No. 8

TARIFF

FOR

GAS SERVICE

Applicable

in

Thirty three towns in New Hampshire
served in whole or in part.

(For detailed description, see Service Area)

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day, Year, in Docket No. DG 17-048

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I. GENERAL TERMS AND CONDITIONS

1 SERVICE AREA

A. Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Keene, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelham, Pembroke, Sanbornton, Tilton, Windham,and part of Canterbury and Winnisquam.

2 GENERAL TERMS AND CONDITIONS

A. Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission") and is open to inspection at the offices of the Company.

B. Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the Commission and such changes, when effective, shall have the same force as the original tariff.

C. Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

D. Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

E. No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

F. Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

G. Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

H. Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

3 CHARACTER OF SERVICE

A. Gas Supply. This Tariff applies only to the supply of gas, having a thermal content of nominally 1,000 British thermal units per cubic foot at supply pressures available in the locality in which the premises to be served are situated.

B. Determination of Therms. The gas for any billing period, expressed in hundreds of cubic feet (ccf), shall be multiplied by the average Btu of the gas send out as determined below and divided by 1,000 in order to determine the number of therms consumed in the billing period. For billing purposes, gas therms shall be determined on a “dry” basis.

The Btu therm factor of the gas sendout shall be calculated for each billing cycle from the daily weighted average Btu of the natural gas delivered to the Company by its suppliers and the gas produced at the Company’s peak-shaving plants. The daily average Btu content shall be determined by appropriate gas measurement devices operated by the Company or its supplier.

C. Delivery of Gas Supply. The rates specified in this tariff are based upon the supply of service to a single customer through one delivery and metering point.

D. Use of Service at Separate Properties. The use of service at two or more separate properties will not be combined for billing purposes.

4 CUSTOMER’S INSTALLATION

A. Point of Delivery. Upon request, the Company will designate a point at which the customer shall terminate his piping for connection to the meter of the Company, but such information does not constitute an agreement or obligation on the part of the Company to furnish service.

B. Space for Meter. The customer shall provide, free of expense to the Company, a dry, warm and otherwise suitable place for the regulator or regulators, meter or meters, or other equipment of the Company which may be necessary for the fulfillment of such contracts as may be entered into with the Company.

C. Location of Meter. The space provided for the Company’s meters and equipment shall be convenient access to the Company’s employees and, as near as possible, to the point where the service supply pipe enters the customer's building. Its location shall be such that the meter connections are not concealed by plaster or sheathing and shall be otherwise acceptable to the Company.

D. Reverse Flow. The customer may be required to install check valves or other devices to prevent compressed air or other gases from entering the Company’s mains.

5 APPLICATION FOR SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of the applicant’s use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Right to Reject. The Company may reject any application for service which would involve excessive cost to supply, or which might affect the supply of service to other customers, or for other good and sufficient reasons.

C. Special Contracts. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, contracts of longer terms as specified in the rate, or with a special guarantee of revenue, or both, may be required to safeguard such investment.

D. Unauthorized Use. Unauthorized connection to the Company's gas service supply facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company without notice. The use of service without notifying the Company and without enabling the Company to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last meter reading of the Company's meter immediately preceding the user's occupancy as shown by the Company's books.

E. Managed Expansion Program. The Managed Expansion Program targets gas expansion in specific areas that have high potential for demand. Each Managed Expansion Program project includes a Main Extension. Customers under this program avoid a portion or all of a contribution in aid of construction which would otherwise be required absent the Managed Expansion Program.

6 CREDIT

A. Prior Debts. Service will not be furnished to former customers until any indebtedness to the Company for previous service has been satisfied.

B. Deposits. Before rendering or restoring service, the Company may require a deposit subject to the Commission's Rules and Regulations. (See Puc 1200 rules).

7 SERVICE AND MAIN EXTENSIONS

A. Definitions. The following are definitions of terms used in these provisions relative to main and service extensions and are applicable only in the main and service extensions provisions.

1. Service and Main Extensions. Extensions that require the construction of a new gas main and a service from that new main in order to provide requested gas service to a customer.

2. Service Extensions. Extensions from an Existing Gas Main to the point of delivery on the customer's premises.

3. Main Extension. An extension of the new gas main portion of a Service and Main Extension.

4. Existing Gas Main. A main that is installed in the street and through which gas is flowing.

5. Abnormal Costs. Abnormal Costs are service and/or main construction costs that are attributable to frost or ledge (including ditching or backfilling necessitated as a result of the presence of frost or ledge),and/or other conditions not typically encountered in service and/or main construction that are peculiar to the particular service and/or main construction concerned. Abnormal Costs are to be paid by the customer.

6. Extra Footage. The charge (contribution in aid of construction) for Extra Footage is $31.54 per foot. The charge will be updated annually by calculating the historical average cost per foot for Service Extensions, excluding overheads, for the most recent calendar year and the updated charge shall be effective April 1.

7. Estimated Annual Margin. The Estimated Annual Margin is equal to the estimated revenue to be derived from the monthly Customer Charge and delivery charge to be received from the customer for gas service utilizing the Service and Main Extension or Service Extension during the first twelve

(12) months after completion of the extension. The Estimated Annual Margin does not include revenue received by the Company for the cost of gas and local distribution adjustment factor.

8. Estimated Cost of Construction. For the purpose of determining the cost of Service and Main Extensions, Estimated Cost of Construction of mains and/or services includes the cost of labor and materials for such construction, and incidental or associated miscellaneous costs, but excluding overheads. Miscellaneous costs include, but are not limited to, meter(s), traffic control and city and town road permits and degradation fees. The customer may perform on-site trenching and backfilling in accordance with the Company's specifications, in which case the Estimated Cost of Construction will be reduced to reflect the costs avoided by the Company as a result of the customer's performance of the work.

B. Costs of Extensions. In areas where the Company is authorized to operate, subject to the Application for Service provisions of this tariff, service is available as follows:

1. Residential Service Extensions. Residential Service Extensions up to 100 feet in length will be installed at no charge to customers served under either a (i) residential heating rate; or (ii) a residential non-heating rate provided that such extension is installed during the installation of a Main Extension or during the performance of work on cast iron/bare steel main replacements; unless there are Abnormal Costs associated with such extensions, in which case the customer shall be charged for the Abnormal Costs. For residential Service Extensions in excess of 100 feet, the customer will be charged for the Extra Footage, plus any Abnormal Costs. This Section 7(B)(1) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

2. Commercial and Industrial Service Extensions. Commercial and industrial Service Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service Extension, excluding any Abnormal Costs. If the Estimated Annual Margin is less than one-sixth of the Estimated Cost of Construction, the customer will be required to pay to the Company, in advance, any amount by which the Estimated Cost of Construction of the Service Extension exceeds six times the Estimated Annual Margin. Abnormal Costs are charged separately and are not included in the Estimated Cost of Construction for the purpose of this calculation. This Section 7(B)(2) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

3. Service and Main Extensions of Less Than $1,000,000. The Company shall not commence construction on a Service and Main Extension for which the Estimated Cost of Construction is less than $1,000,000 until the sum of (i) six times the Estimated Annual Margin for all commercial and industrial customers who have committed to take service, plus (ii) eight times the Estimated Annual Margin for all residential customers who have committed to take service equals or exceeds 25% of the Estimated Cost of Construction.

   a. Residential. Residential Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-eighth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-eighth of the Estimated Cost of Construction, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and eight times the Estimated Annual Margin, plus any Abnormal Costs.

If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated equally among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main. Abnormal Costs associated with Main Extensions will be allocated equally among all customers, unless such costs can be attributed to specific customers.

b. Commercial and Industrial. Commercial and industrial Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-sixth of the cost of construction of the Service and Main Extensions, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and six times the Estimated Annual Margin, plus any Abnormal Costs.

c. If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include in such calculations the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

d. Extensions Serving Customers in More Than One Rate Class. If the Main Extension will serve both residential and commercial or industrial customers, the Company will determine whether a contribution will be required by the customers by calculating the difference between the Estimated Cost of Construction of the Main and Service Extensions and (i) six times the Estimated Annual Margin for all commercial and industrial customers to be served, plus (ii) eight times the Estimated Annual Margin for all residential customers to be served. The Company will also include in the above calculations the Estimated Annual Margin and the Estimated Cost of Construction of Service Extensions for all existing premises for which the Company reasonably anticipates will take service. If the difference described above is positive, the customers will be required to pay to the Company such difference. The amount of payment will be allocated among all metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

4. Service and Main Extensions Greater Than or Equal to $1,000,000. If the cost of the Main Extension equals or exceeds $1,000,000, then in addition to the requirements specified in Section 7(B)(3), the Company will not commence construction unless a discounted cash flow analysis demonstrates a positive net present value over a 10-year period of the difference between the Estimated Annual Margin and the revenue requirement associated with the Estimated Cost of Construction.

C. Failure to Use Installed Gas Service. If a customer fails, within nine months after the date a service is installed under this Section 7, either in whole or in part, to make use of the service, the customer will reimburse the Company for all costs of constructing, removing and retiring the service less any contribution in aid of construction made by the customer for the service, which will be forfeited.

D. Easements, Etc. The Company is not required to construct extensions other than in public ways unless the customer provides, in advance and without expense or cost to the Company, all necessary permits, consents, authorizations and right-of-way easements, satisfactory to the Company, for the construction, maintenance and operation of the pipeline.

E. Shortest Distance. Services are run the shortest practical safe distance to the meter location. However, a customer may have the Company install a longer alternate service provided that the customer pays for the extra expense in advance of installation.

F. Winter Construction. Ordinarily, no new service pipes or main extensions are installed during the winter conditions (when frost is in the ground) unless the customer defrays the extra expenses.

G. Timing and Refunding of Contribution. Except as otherwise agreed by the Company under unusual circumstances, any required contribution in aid of construction will be made prior to installation by the Company of a service. To help cover the Company's expenses, damages and lost business, if substantial construction of the building or buildings for which gas service has been sought is not commenced by the earlier of (1) November 30th next following submission of the application; or (2) the date when the Company commences construction of the main and service concerned prior to withdrawal of the application, ten percent (10%) of the contribution will be forfeited to the Company and will not be returned to the customer. The balance of the contribution will be refunded if and when the application is withdrawn, or will be applied toward the new contribution if the customer submits a new application for service or subsequently commences construction of the building or buildings. A new application may be submitted at any time.

H. Reasonable Duration and Non-Discrimination. Under none of the foregoing provisions will the Company be required to install service pipes or to contract main extensions where the business to be secured may not be of reasonable duration or will tend, in any way, to constitute unreasonable discrimination.

I. Title. Title of all extensions constructed in accordance with the above shall be vested in the Company.

J. Other Requirements. The Company generally will not approve any application or, if it shall have given such approval, will not proceed or continue with main and/or service construction unless the Company is satisfied

1. That the final site plans, sub-division plans and plans and specification for building or buildings to be served by the main and/or service concerned, including plans for waste disposal, water and other associated systems and facilities, have been prepared and approved by owner;

2. That all permits, exceptions, approvals and authorizations of governmental bodies or agencies required for construction of such building or buildings and associated systems and facilities have been obtained;

3. That the customer is proceeding or plans promptly to proceed with such construction; and

4. That nothing has occurred or failed to occur which will or is likely to prevent or interfere with such construction.

8 INTRODUCTION OF SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of his use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Defective Installation. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

C. Unsatisfactory Installation. The Company may refuse to connect if, in its judgment, the customer's equipment or use thereof might injuriously affect the equipment of the Company or the Company's service to other customers.

9 COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

A. Meters and Regulators. The Company shall furnish and install, maintain and own, any meter or meters, regulator or regulators required in the supply of service. For certain large customers, the Company shall furnish, install and maintain, at the customer’s expense, any remote meter reading equipment to record usage for daily balancing. Such equipment shall remain the property of the Company at all times.

B. Customer's Responsibility. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property, the customer shall pay the costs of repairs and replacements.

C. Relocation and/or Replacement of Company Equipment. The original service connection, including piping, meters and all other necessary or incidental equipment, which remains the property of the Company, shall be installed by the Company at its expense unless otherwise expressly provided in this tariff. Subsequent relocation and/or replacement of any such equipment on private property, whether it be for one or more service connections, shall be performed by the Company at the customer's expense unless such work is done at the request of the Company and for its convenience, in which case the Company shall bear the expense.

D. Protection by Customer. The customer shall protect the equipment of the Company on his premises and shall not permit any persons, except a Company employee having a Company photo identification card or other Company identification, to break any seals upon or do any work on any meter, service supply pipe, or other equipment of the Company located on the customer's premises.

E. Tampering. In the event the Company's meter or other property is being tampered with or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter and for any repairs or replacements required as well as for costs of inspections, investigations, and protective installation.

F. Right of Access. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, testing, repairing, removing, or exchanging any or all equipment belonging to the Company.

G. Ownership and Removal. All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service for whatever cause.

10 SERVICE CONTINUITY

A. Regularity of Supply. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service, but should the supply be interrupted by the Company for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted or fail by reason of accident, strike, legal process, state or municipal interference, or any cause whatsoever beyond its control, the Company shall not be liable for damages, direct or inconsequential, resulting from such interruption or failure.

B. Notice of Trouble. The customer shall notify the office of the Company immediately should the service be unsatisfactory for any reason or should there be any defects, leaks, trouble, or accident affecting the supply of gas.

11 CUSTOMER'S USE OF SERVICE

A. Resale Forbidden. The customer shall not, directly or indirectly, sell, sublet, assign, or otherwise dispose of to others, gas purchased from the Company, or any part thereof, without the consent of the Company. This rule does not apply to a public utility Company purchasing gas in bulk expressly for the purpose of delivering it to others.

B. Fluctuations. Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system. In the case of violation of this rule, the Company may discontinue service or require the customer to modify its installation and/or equip it with approved controlling devices.

C. Additional Load. The service supply pipe, regulators, meters, and equipment supplied by the Company for each customer have definite capacities. The customer shall notify the Company of substantial changes in service requirements or location of appliances.

12 INSPECTIONS

A. Company's Right to Inspect. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any time later and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements. However, such inspection, failure to inspect, or failure to reject shall not render the Company liable or responsible for any losses or damage resulting from defects in the installation, piping or appliances, from violation of Company rules, or from accidents which may occur upon the premises of the customer.

13 MEASUREMENT

A. Supply of Meters. The measurement of gas service shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment and may, from time to time, change or alter the equipment. The Company's sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

B. Special Measurements. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments on the premises of any customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the customer's load.

14 METER TESTS

A. Meter Tests. Meters are tested according to NHPUC Rules and Regulations. (See Puc 500 rules).

B. Request Tests. The fee for a special request test is $20.00 when scheduled at the mutual convenience of the Company and the customer; otherwise the amount is $30.00. (See Puc 500 rules).

C. Customer's Bill Adjustment. Should any meter fail to register correctly, the quantity of gas consumed will be determined by the Company based on information supplied by the customer and known by the Company subject to NHPUC Rules and Regulations. (See Puc 500 rules).

15 DISCONNECTION BY THE COMPANY

A. Disconnection by the Company. The Company may disconnect its service to a customer for violation of its rules subject to NHPUC Rules and Regulations. (See Puc 1200 rules).

B. Non-Payment Shut-Off. The Company may disconnect its service on reasonable notice and remove its equipment in case of non-payment of amounts billed for gas usage.

C. Shut-Off for Cause. The Company may disconnect its service on reasonable notice if entry or access to its meter or meters is refused, obstructed, or hazardous, or for other violation of the Company's standard requirements.

D. Safety Shut-Off. The Company may disconnect without notice if the customer's installation has become dangerous or defective.

E. Defective Equipment. The Company may disconnect without notice if the customer's equipment, or use thereof, might injuriously affect the equipment of the Company or the Company's service to other customers.

F. Shut-Off for Fraud. The Company may disconnect without notice for abuse, fraud or tampering with the connections, meters or other equipment of the Company.

G. Reconnection Charge. A reconnection charge is made for reconnection of service discontinued by the Company and is payable in advance in addition to all other amounts due. The reconnection charge is made instead of the meter account charge. The amount of the reconnection charge is the same as the comparable meter account charge except when it has been necessary to dig up the service pipe or connection to effect discontinuance of service. In such cases, the reconnection charge is the price of removal and restoration of service pipe or connection.

16.1 COST OF GAS CLAUSE

A. Purpose. The purpose of this Cost of Gas Clause is to establish procedures that allowthe Company, subject to the jurisdiction of the Commission, to adjust, on a semiannual basis, its rates for firm gas sales in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchased gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit to customers receiving firm service from the Company all supplier refunds and capacity release sales.

B. Applicability. This Cost of Gas Clause ("COGC") shall be applicable to the Company and all firm gas sales made by the Company, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the NHPUC. See Section 16(N), "Other Rules."

C. Cost of Firm Gas Allowable for COGC. All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, hedging related costs, other gas supply expense incurred to procure and transport supplies and commodity related bad debt expense, the gas used in Company operations, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the COGC. Any costs recovered through application of the COGC shall be identified and explained fully in the semiannual filings outlined in Section 16(M).

D. Effective Date of Cost of Gas Factor. The seasonal Cost of Gas Factor ("COG") shall become effective upon NHPUC approval on the first day of each season as designated by the Company. Unless otherwise notified by the NHPUC, the Company shall submit COG filings as outlined in Section 16(M) of this clause on or before the first business day in September...

E. Definitions. The following terms shall be defined in this section, unless the context requires otherwise.

1. Bad Debt Expense: The uncollectible expense attributed to the portion of the Company's revenue associated with the recovery of gas costs under this clause.

2. Capacity Release Revenues: The economic benefit derived from the sale or release of transportation and storage capacity that the Company has under contract.

3. Carrying Charges: Interest expense calculated on the average monthly balance using the *monthly* prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end of month balance.

4. Correction Factor: Seasonal Adjustment necessary to align the peak day volumes used to calculate the Commercial and Industrial load factor ratios with the seasonal Commercial and Industrial High Winter and Low Winter throughput volumes applied to the cost of gas calculations.

5. Direct Gas Costs: All purchased gas costs including supplier, storage and pipeline demand and commodity costs, as well as the commodity costs for local manufactured gas (Liquid Propane Gas (“LPG”) and Liquefied Natural Gas (“LNG”)).

6. Economic Benefit: The difference between the revenues received and the marginal cost determined to serve non-core customers.

7. Inventory Finance Charges: As billed in each Winter Season for annual charges. The total shall represent an accumulation of the projected charges as calculated using the monthly average of financed inventory at the existing or anticipated financing rate through a trust or other financing vehicle.

8. Local Production and Storage Capacity Costs: The costs of providing storage service from the Company's storage facilities (*i.e.*, LNG and LPG) as determined in the Company's most recent rate proceeding.

9. Market Based Allocator (“MBA”): The method used to allocate gas costs among Commercial and Industrial Customer Classifications. These ratios are presented in Section 16(F).

10. Non-Core Commodity Costs: The commodity cost of gas assigned to non-core sales to which the COG is not applied.

11. Non-Core Sales: Sales made under non-traditional off-system sales.

12. Non-Core Sales Margins: The economic benefit derived from non-core transactions to which the COG is not applied, including non-core sales generated from the use of the Company's Gas Supply Resource portfolio.

13. Summer Commodity: The gas supplies procured by the Company to serve firm load in the Summer Season.

14. Summer Demand: The gas supply demand and transmission capacity procured by the Company to serve firm load in the Summer Season.

15. Summer Season: The calendar months May 1 through October 31.

16. Off-System Sales Margin: The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

17. Winter Commodity: The gas supplies procured by the Company to serve firm load in the Winter Season.

18. Winter Demand: Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.

19. Winter Season: The calendar months November 1 through April 30.

20. PR Allocator: The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.

21. Purchased Gas Working Capital: The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

F. Approved Cost. The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

Variable	Description	Approved Figure
MISC	Miscellaneous Overhead	$13,170
PS	Production and Storage Capacity	$1,980,428
WCA%	Working Capital Allowance Percentage	3.91%

Bad Debt % Measurement and Reconciliation Period	COG Recovery Period	Actual Bad Debt Rate	Bad Debt allowed Recovery Rate
May 2010 – April 2011	November 2011 – October 2012	Actual	Actual
May 2011 – April 2012	November 2012 – October 2013	Greater than 2.9%	Actual less 0.4
		2.5% to 2.9%	2.5%
		Less than 2.5%	Actual
May 2012 - April 2013 and each subsequent May – April period thereafter	November 2013 - October 2014 and each subsequent November – October period thereafter	Greater than 3.3%	Actual less 0.8
		2.5% to 3.3%	2.5%
		Less than 2.5%	Actual

If the Company's actual bad debt percentage is reduced to 2.5% or less during any 12 month period, which need not be the same 12 months as the measurement periods defined above, then beginning with the reconciliation filing for the period during which this bad debt percentage was achieved the Company shall thereafter recover its actual gas supply related bad debt on a fully reconcilable basis and the percentages in the table above shall no longer apply. The actual bad debt percentage shall be calculated by dividing the Company's actual net write-offs for the relevant measurement period by its revenue for the same period.

G. Cost of Gas (COG) Calculations by Customer Class. The COG Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group

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James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

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to the total system unit capacity cost that is determined in the Company's submittal of its Capacity Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment C of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

GROUP	CUSTOMER CLASSES
Residential	Residential Heating and Non-Heating
Commercial and Industrial: Low Winter Use	G-51 through G-58
Commercial and Industrial: High Winter Use	G-41 through G-46

Winter Season Cost of Gas Formula (CGw)

The Winter Season COG shall be comprised of Winter Demand costs, Winter commodity costs, Winter reconciliation costs, Winter working capital reconciliation, Winter bad debt expenses, local production and storage capacity costs, and miscellaneous and A&G costs calculated at the beginning of the Winter Season according to the following formula:

$$CGw = Dw + Cw + Rw + WCRw + BDw + PS + ((MISC + Rbd) \times \frac{W{:}Sales)}{A{:}Sales}$$

Winter Demand Cost (Dw) Formula

$Dw = DEMw – NCSMw + WCwd – R1d – R2d$
and:

$NCSMw = CRRw + OSSMw + SBdw$
and:

$WCwd = (DEMw – NCSMw) \times WCA\% \times CC$
where:

CGw = The total cost of gas for the Winter Season for the Company’s firm sales customers previously defined.

BDw = Bad Debt expense for the Winter Season.

Cw = Commodity-related direct gas cost for the Winter Season.

Dw = The total Winter Demand costs.

DEMw = Demand Charges allocated to the Winter Season defined in Section 16(E).

NCSMw = The Non-Core Sales Margins equal to the sum of the Winter Season returnable Capacity Release Revenues, and Off-System Sales Margins.

WCwd = Working Capital allowable associated with demand charges allocated to the Winter Season as defined in Section 16(K).

R1d, R2d = Supplier demand-related refunds - The Supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

CRRw =	The returnable Capacity Release Revenues allocated to the Winter Season. See Section 16(E).
OSSMw =	The returnable Off-System Sales Margins allocated to the Winter Season. See Section 16(E).
SBdw =	Demand revenues received from Firm Stand-By Sales Service customers in the Winter Season.
WCA % =	Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.
CC =	Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.
Rw =	Reconciliation Costs – Winter Season deferred gas costs, Account 1920-1740 balance, inclusive of the associated Account 1920-1740 interest, as outlined in Section 16(J).
WCRw =	Working Capital reconciliation adjustment associated with Winter Gas Costs - Account 1163-1422 balance as outlined in Section 16(K).
PS =	The total dollar amount of costs associated with the local production and storage capacity gas less any production and storage capacity assignment revenues. Refer to Section 16(F) for this dollar amount.
MISC =	The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. Refer to Section 16(F) for this dollar amount.
Rbd =	Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance
W:Sales =	Forecasted firm sales volumes associated with the Winter Season.
A:Sales =	Forecasted annual firm sales volumes.

Winter Season Commodity (Cw) Formula

Cw = COMw + FC + WCwc – R1c – R2c
and:

COMw = WSC – NCCCw - SBcw
and:

WCwc = (COMw + FC) × WCA% × CC
where:

COMw =	Commodity Charges allocated to the Winter Season as defined in Section 16(E).
FC =	Inventory finance charges as defined in Section 16(E).
WCwc =	Working Capital Allowable Associated with commodity charges allocated to the Winter Season as defined in Section 16(K).
R1c, R2c =	Supplier commodity-related refunds - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds". See Section 16(I).

WSC = Commodity charges associated with gas supply sent out in Winter Season as defined in Section 16(E).

NCCCw = Non-Core Commodity Costs incurred in the Winter Season as defined in Section 16(E).

SBcw = Winter Season commodity revenues received from Firm Stand-By Gas Supply Service sales customers.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Winter Bad Debt (BDw) Formula

BDw = BD% x (Dw + Cw + Rw + WCRw)
where:

BDw = Forecasted gas supply cost related Bad Debt Expense calculated for Winter Season.

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.

Dw = Demand related costs in the Winter Season as previously defined.

Cw = Commodity related costs in the Winter Season as previously defined.

Rw = Reconciliation Costs – Winter Season deferred gas costs as previously defined.

WCRw = Winter Season Working Capital Reconciliation adjustment as previously defined.

Residential Winter Season Cost of Gas (COGwr)

All residential firm sales customers will pay the same Cost of Gas for the Winter Season. The factor represents the total forecasted Winter Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGwr = \frac{CGw}{W{:}Sales}$$

where:

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers previously defined.

W:Sales = Forecasted sales volumes associated with the Winter Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Summer Season Cost of Gas (COG) Formula (CGs)

The Summer Season COG shall be comprised of Summer demand costs and Summer commodity costs, Summer reconciliation costs, Summer working capital reconciliation, plus a Summer bad debt charge, and a miscellaneous and A&G charge calculated at the beginning of the Summer Season according to the following formula:

$$CGs = Ds + Cs + Rs + WCRs + BDs + ((MISC + Rbd) \times \frac{S:Sales}{A:Sales})$$

Summer Demand Cost (Ds) Formula

Ds = DEMs + WCsd – Rld – R2d
and:

WCsd = DEMs × WCA% × CC
where:

A:Sales = Forecasted annual sales volumes.

BDs = Bad Debt Expense for Summer Season.

Cs = Commodity-related direct gas costs for the Summer Season.

CGs = The total cost of gas for the Summer Season for the Company's firm sales customer previously defined.

DEMs = Demand charges allocated to the Summer Season defined in Section 16(E).

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. Refer to Section 16(F) for this dollar amount.

R1d, R2d = Supplier refunds from pipeline demand charges - The per unit supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

Rs = Summer Season Reconciliation Costs - Account 1920-1741 balance, inclusive of the associated Account 1920-1741 interest, as outlined in Section 16(J).

S:Sales = Forecasted sales volumes associated with the Summer Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance.

WCRs = Working Capital reconciliation adjustment associated with Summer gas costs – Account 1163-1424 as outlined in Section 16(K).

WCsd = Working Capital allowable costs associated with demand costs allocated to the Summer Season as defined in Section 16(K).

Summer Season Commodity Cost (Cs) Formula

Cs = COMs – NCCCs + WCsc – R1c – R2c
and:

WCsc = (COMs – NCCCs) × WCA% × CC
where:

COMs =	Commodity charges associated with gas supply sent out in the Summer Season as defined in Section 16(E).
WCsc =	Working Capital allowable costs associated with commodity charges allocated to the Summer Season as defined in Section 16(K).
R1c, R2c =	Supplier refunds from pipeline commodity charges - The supplier refunds associated with refund program credits derived from Account 5541-8048, “Undistributed Gas Suppliers' Refunds.”
NCCCs =	Non-core commodity costs incurred in the Summer Season as defined in Section 16(E).
WCA % =	Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.
CC =	Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Summer Bad Debt (BDs) Formula

BDs = BD% x (Ds + Cs + Rs + WCRs)
where:

BD% =	Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.
BDs =	Forecasted gas supply related Bad Debt Expense calculated for Summer Season defined in Section 16(E).
Ds =	Demand related costs in the Summer Season as previously defined.
Cs =	Commodity related costs in the Summer Season as previously defined.
Rs =	Reconciliation Costs – Summer deferred gas costs as previously defined.
WCRs =	Summer Season Working Capital Reconciliation adjustment as previously defined.

Residential Summer Season Cost of Gas (COGsr)

All residential firm sales customers will pay the same cost of gas for the Summer Season. The factor represents the total forecasted Summer Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGsr = \frac{CGs}{S{:}Sales}$$

where:

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

S:Sales = Forecasted sales volumes associated with the Summer Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Commercial and Industrial Winter and Summer Season Cost of Gas

The Commercial and Industrial customer classes Winter Season Cost of Gas will be based on the Winter Season average cost of gas components used for the Residential Winter Season Cost of Gas. A separate Winter Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58 and a separate Winter Season Cost of Gas Factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

The Commercial and Industrial customer classes Summer Season Cost of Gas will be based on the Summer Season average cost of gas components used for the Residential Summer Season Cost of Gas. A separate Summer Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53,G-54, G-55, G-56, G-57, and G-58 and a separate Summer Season Cost of Gas factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

These Cost of Gas Factors will be computed by applying ratios to the average demand portion of the Winter and Summer Season's cost of gas unit rate times the correction factor and then adding the remaining Residential average cost of gas unit rate.

These factors are calculated according to the following formulas:

Low Winter Use (COGwl) Formula Winter Season

$COGwl = RATIOl \times CFw \times CGwd + CGwo$

Low Winter Use (COGsl) Formula Summer Season

$COGsl = RATIOl \times CFs \times CGsd + CGso$

and:

$$RATIOl = \frac{DCcl}{DDcl} \div \frac{DCc}{DDc}$$

and:

High Winter Use (COGwh) Formula Winter Season

$COGwh = RATIOh \times CFw \times CGwd + CGwo$

High Winter Use (COGsh) Formula Summer Season

COGsh = RATIOh x CFs x CGsd + CGso

and

$$RATIOh = \frac{DCch}{DDch} \div \frac{DCc}{DDc}$$

and:

$$CFw = \frac{(WL:Sales + WH\ Sales)}{(RATIOl \times WL:Sales) + (RATIOh \times WH:Sales)}$$

$$CFs = \frac{(SL:Sales + SH:Sales)}{(RATIOl \times SL:Sales) + (RATIOh \times SH:Sales)}$$

$$CGwd = \frac{Dw}{W:Sales}$$

$$CGwo = \frac{CGw - Dw}{W:Sales}$$

$$CGsd = \frac{Ds}{S:Sales}$$

$$CGso = \frac{CGs - Ds}{S:Sales}$$

DCcl = Bcl * PLrate + (DDcl – Bcl) * REMrate

DCch = Bch * PLrate + (DDch- Bch) * REMrate

PLrate = PL/ PLmdcq

$$REMrate = \frac{(DCc - (Bc*PLrate))}{DDc - Bc}$$

$$DCc = \frac{(DC \times DDc)}{DD}$$

where:

Bc = The daily base load for all the Commercial and Industrial rate classes

Bch = The daily base load for the Commercial and Industrial rate classes G-41, G-42, G-43, G-44, G-45 and G-46.

Bcl = The daily base load for the Commercial and Industrial rate classes G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

CFs = Summer Season Commercial and Industrial gas cost correction factor.

CFw = Winter Season Commercial and Industrial gas cost correction factor.

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers as previously defined.

DC =	The annual forecasted pipeline, storage and peaking demand charges plus the total production and storage capacity costs, as stated in Section 16(F).
DCc =	The Commercial and Industrial rate classes pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs.
DCch =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to Commercial and Industrial High Winter Use rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DCcl =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to the Commercial and Industrial Low Winter Use rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
DD =	Total peak design day determinants.
DDc =	The peak design day determinants allocated for all the Commercial and Industrial rate classes.
DDch =	The peak design day determinants for the Commercial and Industrial rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DDcl =	The peak design day determinants for the Commercial and Industrial rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
Ds =	The total Summer Demand charges as defined below.
Dw =	The total Winter Demand charges as previously defined.
PL =	The annual forecasted pipeline only demand charges
PLmdcq =	The maximum daily contract pipeline volume available to the Company.
PLrate =	The pipeline demand rate.
RATIOh =	Ratio of the average high Winter Use class Cost of Gas low load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
RATIOl =	Ratio of the average low Winter Use class Cost of Gas high load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
REMrate =	The weighted average demand rate for storage and peaking supplies.
S: Sales =	Forecasted sales volumes associated with the Summer Season.
SH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
SL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.
W:Sales =	Forecasted sales volumes associated with the Winter Season.
WH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
WL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.

H. Non-Core Sales Margins ("NCSM"). One hundred percent (100%) of margins from Off-System Sales and all revenues from Capacity Release will be credited to firm sales customers during the winter season through operation of the COG.

I. Gas Suppliers' Refunds. Account 5541-8048: Refunds from suppliers of gas, from upstream capacity suppliers and suppliers of product demand are credited to Account 5541-8048, "Commodity and Demand Refunds." Transfers from these accounts will reflect as a credit in the semiannual calculation of the COG to be calculated as follows:

Refund programs shall be initiated with each semiannual COG filing and shall remain in effect for a period of one year. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. Refunds shall be segregated by demand and commodity charges and distributed volumetrically, producing per unit refund that will return the principal amount with interest as calculated using the Company's average short-term cost of borrowing for the month to the average of the beginning and end of month balances of refunds. The Company shall track and report on all Account 5541-8048 activities as specified in Section 16(K).

J. Reconciliation Adjustments – Various Accounts.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Capacity Costs Allowable per Winter Season Formula shall be:

(1) Charges associated with upstream storage transmission capacity and product demand procured by the Company to serve firm load in the Winter Season, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Charges associated with peaking, downstream production and storage capacity to serve firm load dispatching costs, and other administrative and general expenses in connection with purchasing gas supplies in the Winter Season from the Company's most recent test year and allocated to firm sales service.

(3) Non-Core Sales Margins or economic benefits associated with returnable capacity release and off-system sales.

(4) Credits associated with firm Stand-by Gas Supply Service Monthly Reservation Charges, daily imbalance charges and fixed component of penalty charges billed transportation customers in the Winter peak Season.

(5) Winter Season Demand Cost carrying charges.

b. Gas Costs Allowable Per Winter Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter Season.

(2) Credit non-core commodity costs assigned to non-core customers to which the COGC does not apply, as defined in Section 16(H) (NCCCw).

(3) Inventory finance charges (FC).

(4) Winter Season commodity cost carrying charges.

c. Capacity Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with transmission capacity and product demand procured by the Company to serve firm load in the Summer Season

(2) Credits associated with daily imbalance charges and fixed component of penalty charges billed transportation customers in the Summer Season.

(3) Summer Season demand cost carrying charges.

d. Gas Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

(3) Summer Season commodity cost carrying charges.

e. Costs Allowable Per Bad Debt Formula shall be:

(1) Costs associated with uncollected gas costs, incurred by the Company to serve sales load. Such costs represent the bad debt expense related to the gas supply related write-off of sales customers and will be computed by multiplying actual gas costs by the Bad Debt Allowed Recovery Rate specified in Section 16(F). The reconciliation adjustment each season will be computed as the difference between the actual supply related bad debt revenues and the actual gas costs multiplied by the actual Bad Debt Allowed Recovery Rate as specified in Section 16(F).

(2) Account 1920-1743 – Annual Bad Debt, carrying charges.

2. Calculation of the Reconciliation Adjustments: These accounts contain the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Winter Season Gas Costs (Account 1920-1740) and Summer Season Gas Costs (Account 1920-1741), Account 1920-1740 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Winter Season Gas Cost for each Customer Classification, (COGwr, COGwl and COGwh) times monthly firm sales volumes for each Customer Classification, and the total costs allowable per the Winter Season gas cost formula. Account 1920-1741 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Summer Season Gas Cost for each Customer Classification, (COGsr, COGsl and COGsh) times monthly firm sales volumes for each Customer Classification, and the total gas costs allowable per the Summer Season demand formula.

Carrying Charges shall be calculated on the average monthly balance of each subaccount. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

The annual bad debt reconciliation adjustments Rbd shall be determined for use, incorporating the bad debt balances in Account 1920-1743.

The bad debt account balance contains the accumulated difference between the Bad Debt Allowed Recovery Rate for the applicable period multiplied by the actual gas costs and the actual supply related bad debt revenues for the Winter and Summer COG filings.

The Winter Season reconciliation shall be filed with the NHPUC no later than July 29 of each year.

The Summer Season reconciliation shall be filed with the NHPUC no later than January 31 of each year.

K. Working Capital Reconciliation Adjustments - Accounts 1163-1422 and 1163-1424.

1. The following definitions pertain to reconciliation adjustment calculations:

   a. Working Capital Demand Gas Costs Allowable per Winter Season Gas Formula shall be:

      (1) Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the Winter period, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

      (2) Carrying charges.

   b. Working Capital

      (1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter season.

      (2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

      (3) Carrying charges.

   c. Working Capital Demand Gas Costs Allowable per Summer Season Gas Formula shall be:

      (1) Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Summer Season.

      (2) Carrying charges.

   d. Working Capital Commodity Gas Costs Allowable per Summer Season Gas Formula shall be:

      (1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

      (2) Non-core commodity costs associated with non-core sales.

      (3) Carrying charges.

   e. The Winter and Summer Cost of Gas working capital allowances shall be calculated by applying the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F).

2. Calculation of the Reconciliation Adjustments

   a. Accounts 1163-1422 and 1163-1424 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance cost. The actual monthly working capital allowance shall be calculated by multiplying the actual gas costs times the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F), to the actual Direct Gas Costs allowable.

   b. The Winter Season working capital reconciliation adjustment (WCRw) shall be determined for use in the Winter Season Gas Cost calculations incorporating the Winter Season working

capital account 1163-1422. A Summer Season working capital reconciliation adjustment (WCRs) shall be determined for use in the Summer Season Gas Cost calculations incorporating the Summer Season working capital account 1163-1424 balance.

L. Application of COG to Bills: The Company will employ the COGs as follows: The COGs ($/therm) for each customer group for each season shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volume within the corresponding customer classification. The Cost of Gas will be applied to gas consumed on or after the first day of the month in which the cost of gas becomes effective.

M. Information Required to be Filed with the NHPUC.

1. Reconciliation Adjustments: The Company shall file with the NHPUC a seasonal reconciliation of gas costs and gas cost collections containing information in support of the reconciliation calculation set out in Sections 16(J) (2) and 16(K) (2). Such information shall include the complete list of gas costs recoverable through the COGC over the previous season. This seasonal reconciliation shall be filed with the respective seasonal COG reconciliation filing, along with complete documentation of the reconciliation adjustment calculations.

   Additionally, information pertaining to the Cost of Gas shall be filed with the NHPUC in accordance with the format established by the NHPUC. Reporting requirements include filing the Company's monthly calculation of the projected over or under-collection with the NHPUC, along with notification by the Company to the NHPUC of any revised COG for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month.

   The Company shall file with the NHPUC an annual reconciliation of bad debt expense and bad debt collections containing information in support of the reconciliation calculation set out in Sections 16(J) (1) and 16(J) (2). Such information shall detail the revenues collected as an allowance for bad debt, as well as the actual bad debt expense associated with gas cost recoverable through the COGC over the 12-month period ending April 30th. This annual reconciliation of bad debt expenses shall be filed with the Winter COG reconciliation filing, along with documentation.

2. Commercial and Industrial COG Ratio: The following factors will be filed annually by the Company for informational purposes. Significant changes in these factors signal the need to evaluate the COG ratios. These variables will assist in predicting significant shifting of the MBA-based escalator of gas costs and resulting changes in the COG ratios:

   a. The percentage of load migration from sales to transportation service in the Commercial and Industrial High and Low Winter Use classes.

   b. The ratio of delivered costs of winter supplies to pipeline delivered supplies.

   c. The July and August consumption for the Commercial and Industrial High and Low Winter classes as a percentage of their annual consumption.

N. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of this tariff, upon such terms that it may determine to be in the public interest.

2. The Company may, without further NHPUC action, adjust the approved COG upward or downward monthly based on the Company's calculation of the projected over or under-collection for the period, but the cumulative adjustments upward shall not exceed twenty-five percent (25%) of the approved COG.

3. The Company may, at any time, file with the NHPUC an amended COG.

4. The operation of the Cost of Gas Clause is subject to all powers of suspension and investigation vested in the NHPUC.

5. The Company shall file both seasonal COG filings on or before the first business day in September. The summer portion of the filing will include COG rates effective May 1 of the following year.

O. Reconciliation Adjustment Accounts.

1163-1422

Winter Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas working capital allowance revenues and Winter Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1163-1424

Summer Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas working capital allowance revenues and Summer Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1740

Winter Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas revenues and Winter Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1741

Summer Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas revenues and Summer Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1743

Annual Bad Debt Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Annual bad debt revenues and annual bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

5541-8048

Commodity and Demand Refunds: This account shall be used to record the refunds from upstream commodity supplies and suppliers of product commodity and transfers of credits in the semiannual calculation of the COG as well as to record the refunds from upstream capacity supplies and suppliers of product demand and transfer of credits in the semiannual calculation of the COG. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

P. Firm Transportation Cost of Gas Charge. To permit the Company to charge its firm transportation customers with a portion of the cost of gas produced by the Company between November 1 and April 30 of each year, there is a Firm Transportation Cost of Gas Charge ("FTCG") which applies to all firm transportation billed under this tariff. This volumetric charge is to compensate firm sales customers for the increase in gas costs, through the use of supplemental liquid fuels, attributable to firm transportation customers during the Winter Period.

1. Application. The FTCG will be calculated for the Winter Period, defined as the period from November 1 through April 30. The FTCG will be applied to billings commencing with the first November revenue billing cycle

2. Purpose. The amount of the FTCG is the estimated liquid costs used for pressure support purposes multiplied by the transportation throughput as a percentage of the total system throughput for the Winter Period. The resulting amount shall be adjusted by the prior period over or under collection, if any, and shall be recovered over the estimated total transportation throughput subject to the FTCG to yield a per therm volumetric charge. The FTCG shall be computed to the nearest one hundredth cent per therm and shown separately on customers' bills. At the conclusion of the Winter Period, the Company will calculate the extent that the FTCG revenues are greater or lesser than actual unit cost. The revenue and liquid costs will be reconciled so that all liquids costs shall be collected from either firm sales or firm transportation customers.

3. Changes. The amount of the FTCG may be changed within the period whenever the unit cost materially deviates from the anticipated unit cost

4. Reporting. The Company shall submit to the New Hampshire Public Utilities Commission, on or before the first business day in September, a copy of the FTCG computation. A reconciliation of the prior period under/over collection will be submitted to the New Hampshire Public Utilities Commission no later than July 29.

Q. Fixed Price Option Program. Fixed Price Option Program. An alternative to the traditional Winter Period cost of gas pricing mechanism may be elected by a residential customer (rates R-1, R-3, R-4, R-5 or R-6) pursuant to the Company's Fixed Price Option Program (the "Program"). The Company may offer up to 50% of its weather normalized firm sales for the prior Winter Period under the Program. The cost of gas rate offered under the Program will remain fixed for all Winter Period deliveries commencing November 1 and ending April 30. The Company shall submit to the New Hampshire Public Utilities Commission on or before September 1 of each year a copy of the fixed price option computation. Once elected, customers must remain on the Program for the duration of the Winter Period, unless service is terminated. There are no maximum or minimum usage levels. No sign up fees apply.

16.2 COST OF GAS CLAUSE – KEENE DIVISION

A. Purpose. To permit the Company to charge its customers in the Keene Division with the cost of gas purchased or produced. A cost of gas rate will be applied to all firm gas billed under this tariff as calculated on the appropriate pages.

B. Application. A cost of gas rate will be calculated for the winter heating period, defined as the period from November 1 through April 30, and a cost of gas rate will be calculated for the summer period, defined as the period from May 1 through October 31.

The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

A. Purpose. The purpose of the Local Distribution Adjustment Clause (“LDAC” or this “Clause”) is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges (“CC”), Revenue Decoupling Adjustment Clause (“RDAC”), Winter Period Surcharges (“WPS”), Environmental Surcharges (“ES”) including the Relief Holder Surcharge (“RHS”) and the Manufactured Gas Program Surcharge (“MGP”), recover gas restructuring expenses (“GRE”), rate case expenses (“RCE”), Residential Low Income Assistance Program costs (“RLIAP”) and any other expenses the NHPUC may approve from time to time.

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	CC 17(C)	RDAC 17(C.1)	ES 17(D)	GRE 17(E)	RCE 17(F)	RLIAP 17(G)
Residential Non-Space Heating – R-1, R-5	2	2	X	N/A	2	X
Residential Space Heating – R-3, R-4, R-6, R-7	2	2	X	N/A	2	X
Small C&I – G-41, G-51, G-44, G-55	2	2	X	X	2	X
Medium C&I – G-42, G-52, G-45, G-56	2	2	X	X	2	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	2	2	X	X	2	X

Notes:
N/A Not applicable
X Applicable to all
1 Applicable to Non-Managed Expansion Program Customers
2 As ordered by the NHPUC

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under

collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

C.1 Revenue Decoupling Adjustment Clause

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on a semi-annual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's Revenue Decoupling Adjustment eliminates the link between customer sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

2. Effective Date: The Winter Season Revenue Decoupling Adjustment Factor ("RDAF") for the Winter Season shall be effective on the first day of each Winter Season as defined herein. The Summer Season RDAF shall become effective on the first day of each Summer Season as defined herein.

3. Applicability: The Revenue Decoupling Adjustment Factor shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC.

4. Definitions: The following definitions shall apply throughout the RDAC:

   a. Actual Base Revenue per Customer is the actual revenue derived from the Company's base rates divided by the Actual Number of Customers for a given season for a Customer Class Group.

   b. Actual Number of Customers is the actual number of customers for the applicable Customer Class Group for the most recently completed Winter Season or Summer Season. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for a given season for a Customer Class Group and dividing by the number of months in each Season.

   c. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

   d. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment amounts. The three Customer Class Groups are as follows:

(1) The Residential Non-Heating Customer Class Group (CG1) shall consist of all customers taking service pursuant to the Company's residential non-heating rate schedule R-1.

(2) The Residential Heating Customer Class Group (CG2) shall consist of all customers taking service pursuant to the Company's residential heating rate schedules R-3, and R-4.

(3) The Commercial and Industrial Customer Class Group (CG3) shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-51, G-52, G-53 and G-54.

e. Summer Season is the continuous period from May 1 through October 31.

f. Winter Season is the continuous period from November 1 through April 30.

g. Benchmark Base Revenue per Customer is the allowed average revenue per Customer for a given season for a Customer Class Group, reflecting the base revenue from the Company's base rate case or other proceeding that results in an adjustment to base rates. The following are the Benchmark Base Revenue per Customer values as approved by the Commission in Docket No. DG 17-048:

Customer Class Group	Benchmark Base Revenue per Customer	
	Winter Season	**Summer Season**
Residential Non-Heating (CG1)	$165.77	$145.53
Residential Heating (CG2)	$433.98	$210.90
Commercial and Industrial (CG3)	$2,200.52	$894.95

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Winter Season and Summer Season, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next corresponding season.

The Revenue Decoupling Adjustment shall be determined by calculating the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer, and multiplying that difference by the Actual Number of Customers for the applicable Customer Class Group. The Revenue Decoupling Adjustment shall equal the sum of the adjustments calculated for each of the three Customer Class Groups and shall include a reconciliation component.

The total Revenue Decoupling Adjustment determined in accordance with Section 5.0 may not exceed plus or minus five percent (±5%) of total base revenues from firm Rate Classes for the most recent corresponding Winter or Summer Season. To the extent that the application of the Revenue Cap results in a Revenue Decoupling Adjustment that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the Revenue

Decoupling Reconciliation for recovery in the subsequent year during the corresponding Winter or Summer Season. Carrying charges shall be calculated on the average deferred balance using the prime lending rate and then added to the end-of-month balance.

b. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CG=1}^{CG=3} \left[\left(BRPC_{T-1}^{CG} - ARPC_{T-1}^{CG} \right) x \; ACUSTS_{T-1}^{CG} \right]$$

If
$RD < (5\% \; x \; DIST \; REV_T)$
And
$RD > (-5\% \; x \; DIST \; REV_T)$

Then
$DEF_{incm} = 0$
And:
$DEF_{rec} = Lower \; of \; (DEF_{balp}) \; or \; \left((5\% \; x \; DIST \; REV_T) - RD \right)$
And:
$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} - DEF_{rec}$
And:

$$RDAF = \frac{RD + RF_{rd} + DEF_{rec}}{P{:}Thru_T}$$

Else:
$DEF_{incm} = RD - (5\% \; x \; DIST \; REV_T)$
And:
$DEF_{rec} = 0$
And
$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} + DEF_{incm}$
And

$$RDAF = \frac{(5\% \; x \; DIST \; REV_T) + RF_{rd}}{P{:}Thru_T}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CG}$: The Actual Number of Customers for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1). Actual number of customers for each Winter or Summer Season shall be the average number monthly customers in that season, calculated by summing the number of equivalent bills in each month of the most recently completed Winter or Summer Season, and dividing by the number of months in the Season.

$ARPC^{CG}_{T-1}$:	The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1), as defined in Section 4.0. For purposes of calculating the Actual Base Revenue per Customer, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.
$BRPC^{CG}_{T-1}$:	The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section 4.0(A) for the most recently completed Winter or Summer Season (T-1).
cg	Customer Class Groups as defined in Section 4.0(D).
DEF_{bal}	The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.
DEF_{incm}	The amount of Revenue Decoupling that must be deferred in the current year based on the difference between plus or minus five percent (+/-5%) of total distribution revenues as determined in accordance with the definition of DIST REV_T in Section 5.0(B).
DEF_{rec}	The amount of deferrals the Company may recover in the current Winter or Summer Season.
P: $Thru:_T$	Forecast Throughput Volumes inclusive of all firm tariff throughput for the Winter or Summer Season.
RD	The Revenue Decoupling adjustment to revenues.
$RDAF_T$:	The Revenue Decoupling Adjustment Factor for the Winter or Summer Season.
RF_{rd}:	Revenue Decoupling Reconciliation Adjustment as described in Section 6.0.
DIST REV_T	The Distribution revenues from all firm rate classes during the most recent Winter or Summer Season.

6. Calculation of the Reconciliation Adjustments

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Winter Season, as calculated by multiplying the Winter Season RDAF times the Winter Season firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues for the Winter Season, plus carrying charges on the average monthly balance using the prime lending rate.

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Summer Season, as calculated by multiplying the Summer Season Revenue Decoupling Adjustment Clause times the Summer Season firm throughput, and the

Revenue Decoupling Adjustment allowed revenues for the Summer Season, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

   The RDAF ($ per therm) shall be truncated at the nearest one one-hundredth of a cent per therm. The RDAF for the Winter Season will be applied usage in the next Winter Season and the RDAF for the Summer Season will be applied to usage in the next Summer Season. The RDAF will be applied to the monthly firm tariff throughput for each customer.

8. Information to be Filed with the Commission

   Information pertaining to the RDAC will be filed with the Commission ninety (90) days prior to the effective dates of the November 1 Winter Season and May 1 Summer Season RDAF. Such information shall include:

   a. the calculation of the applicable revenue decoupling revenue adjustment

   b. the calculation of the revenue decoupling reconciliation adjustment.;

   c. the calculation of annually updated Benchmark Base Revenue per Customer to be utilized in the upcoming Summer and Winter Seasons.

D. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

   The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

E. Expenses Related to Gas Restructuring.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates on an annual basis for the recovery of NHPUC-approved costs associated with the Gas Restructuring Collaborative (Docket DE 98-124).

2. Applicability: The Gas Restructuring Expenses ("GRE") shall be applied to all firm tariffed customers eligible to receive delivery service from the Company as determined in accordance with the provisions of Section 17(F) of this clause. The GRE shall be determined annually by the Company as defined below, subject to review and approved by the NHPUC as provided for in this clause.

3. GRE Allowable for LDAC: Costs associated with the Gas Restructuring Collaborative (DE 98-124), including, but not limited to, any legal, consulting, customer focus group(s) and survey(s),

customer education campaign(s), materials and advertising, subject to review and approval by the NHPUC.

4. Effective Date of GRE Charge: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the GRE applicable to all consumption of tariffed customers eligible to receive delivery service for the subsequent twelve month period commencing with the calendar month of November.

5. Definition: Gas Restructuring Initiatives are activities facilitating the development, design and implementation of unbundled services for all customers.

6. GRE Factor Formula:

$$GREF = \frac{GRE + RAGRE}{A: TPev}$$

where:

A:Tpev Forecast Annual Throughput Volumes of all tariffed customers eligible to receive firm delivery-only service from the Company.

GRE Gas Restructuring Expenses as defined in Section 17(F).05.

RA_{GRE} Gas Restructuring Expense Reconciliation Adjustment - Account 1920-1744, inclusive of the associated Account 1920-1744 interest, as outlined in Section 17(E)(7).

7. Reconciliation Adjustments: Account 1920-1744 shall contain the accumulated difference between revenues toward Gas Restructuring Expenses as calculated by multiplying the Gas Restructuring Expense Factor ("GREF") times monthly volumes of customers eligible to receive firm delivery service and Gas Restructuring expenses allowed, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end-of-month balance.

8. Application of GREF to Bills: The GREF ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the Gas Restructuring Expenses shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual GREF filing shall be required on or before the first business day in September of each year. The GREF filing shall contain the calculation of the new annual GREF to become effective November 1 and shall include the updated annual Gas Restructuring Expense reconciliation balance.

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A: TPev}$$

where:

A: Tpev — Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

RLIAP — RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{RLIAP} — RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP

account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{X} = CC^{X} + RDAC^{X} + ES + GREF^{x} + RCE + RLIAP$$

and:

$$ES^{X} = RHS + MGP$$

where:

$LDAC^{X}$ =	Annualized class specific LDAC.
CC^{X} =	Annualized class specific CC or EE Charge.
$RDAC^{X}$ =	Annualized class specific RDAC.
ES =	Total firm annualized ES.
RHS =	Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH
MGP =	Annualized charge to cover the remediation costs related to former manufactured gas plants.
$GREF^{X}$ =	Total firm annualized class specific Gas Restructuring Expense Factor.
RCE =	Rate Case Expense Factor.
RLIAP =	Residential Low Income Assistance Program Rate

J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

K. Other Rules.

1. (1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

L. Amendments to Uniform System of Accounts.

1920-1744 **Gas Restructuring Expense Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(E).

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(D).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(G).

1163-1756 **Lost Revenue Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C.1).

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

2. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

3. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

4. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

5. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

6. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

7. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

8. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

9. Feedstock Gas: Is defined as natural gas used as a raw material for its chemical properties in creating an end product

10. Process Gas: Is defined as gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels

11. Boiler Fuel: Is considered to be natural gas used as a fuel for the generation of steam or electricity including the utilization of gas turbines for the generation of electricity

12. Alternate Fuel Capabilities: Is defined as a situation where an alternate fuel could have been utilized whether or not the facilities for such use have actually been installed, provided however, where the use of natural gas is for plant protection, feedstock or process uses and the only alternate fuel is propane or other gaseous fuel, then the consumer will be treated as if he had no alternate fuel capability.

B. POLICY

In the event that, due to gas supply restrictions or capacity constraints, the Company is unable to deliver the total requirements of its firm, sales or transportation rate customers, the available volumes of gas will be allocated to the Company's firm rate customers in accordance with the provisions of this policy.

In the event that the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of the customer, customer shall be compensated for such emergency gas at the customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.

As curtailment becomes necessary through each succeeding category, the Company will implement full or partial curtailment of a customer, or by groups of customers, taking into consideration customer load characteristics, the Company's delivery system design and Company load characteristics in a manner which is believed to be in the best interests of customers in general.

C. PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories:

1. Company use for fuel and lost and unaccounted for

2. Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

3. Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

4. Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

5. Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (6), or (7)

6. Firm sales or transportation service including the transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

7. Firm sales or transportation service including transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

D. STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

E. PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service.

II. RATE SCHEDULES

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1

Availability
This rate is available to all residential customers who do not have gas space heating equipment, who consume less than 80% of their normal usage in the six winter months of November through April and whose usage does not exceed 100 therms in any winter month. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	\$0.7176 per day or \$21.50 per 30 day month
Winter Period:	All therms per 30 day month at \$0.2446 per therm
Summer Period:	All therms per 30 day month at \$0.2446 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is \$20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is \$30.00.

Terms and Conditions
Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a \$15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

2 RESIDENTIAL HEATING RATE:
CLASSIFCATION NO. R-3

Availability
This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.8500 per day or $25.50 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5201 per therm
	All over 100 therms per 30 day month at $0.4176 per therm
Summer Period:	First 20* therms per 30 day month at $0.5201 per therm
	All over 20 therms per 30 day month at $0.4176 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

3 LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4

Availability

This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.3400 per day or $10.20 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2080 per therm
	All over 100 therms per 30 day month at $0.1670 per therm
Summer Period:	First 20* therms per 30 day month at $0.2080 per therm
	All over 20 therms per 30 day month at $0.1670 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

<u>Cost of Gas Charge</u>
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

<u>Other Charges for Delivery Service</u>
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

<u>Meter Account Charge</u>
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

<u>Terms and Conditions</u>
For those customers qualifying for the program this rate R-4 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Residential Non Heating Rate R-1.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.9317 per day or $27.95 per 30 day month
Winter Period:	All therms per 30 day month at $0.3180 per therm
Summer Period:	All therms per 30 day month at $0.3180 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program projects area who otherwise would have qualified for Residential Heating Rate R-3.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.1050 per day or $33.15 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.6761 per therm
	All over 100 therms per 30 day month at $0.5429 per therm
Summer Period:	First 20* therms per 30 day month at $0.6761 per therm
	All over 20 therms per 30 day month at $0.5429 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-3.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

6 MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Low Income Residential Heating Rate R-4.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.4420 per day or $13.26 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2704 per therm
	All over 100 therms per 30 day month at $0.2171 per therm
Summer Period:	First 20* therms per 30 day month at $0.2704 per therm
	All over 20 therms per 30 day month at $0.2171 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Low Income Residential Heating Rate R-4.

For those customers qualifying for the program this rate R-7 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-7 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-6. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

7 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFCATION NO. G-41

Availability

This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537 per day or $55.61 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5689 per therm
	All over 100 therms per 30 day month at $0.3130 per therm
Summer Period:	First 20* therms per 30 day month at $0.5689 per therm
	All over 20 therms per 30 day month at $0.3130 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE
CLASSIFICATION NO. G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$5.3197 per day or $159.59 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.4458 per therm
	All over 1000 therms per 30 day month at $0.2952 per therm
Summer Period:	First 400* therms per 30 day month at $0.4458 per therm
	All over 400 therms per 30 day month at $0.2952 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$22.8290 per day or $684.87 per 30 day month
Winter Period:	All therms per 30 day month at $0.2684 per therm
Summer Period:	All therms per 30 day month at $0.1227 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the N Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44

Availability
This rate is Mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-41.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097 per day or $72.29 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.7396 per therm
	All over 100 therms per 30 day month at $0.4069 per therm
Summer Period:	First 20* therms per 30 day month at $0.7396 per therm
	All over 20 therms per 30 day month at $0.4069 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-41.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

**11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE
CLASSIFICATION NO. G-45**

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-42.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$6.9157 per day or $207.47 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.5795 per therm
	All over 1000 therms per 30 day month at $0.3838 per therm
Summer Period:	First 400* therms per 30 day month at $0.5795 per therm
	All over 400 therms per 30 day month at $0.3838 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-42.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-43.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$29.6777 per day or $890.33 per 30 day month
Winter Period:	All therms per 30 day month at $0.2684 per therm
Summer Period:	All therms per 30 day month at $0.1595 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Scheduleswhich present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-43.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537 per day or $55.61 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.3460 per therm
	All over 100 therms per 30 day month at $0.2060 per therm
Summer Period:	First 100* therms per 30 day month at $0.3460 per therm
	All over 100 therms per 30 day month at $0.2060 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this

tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-52

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$5.3197 per day or $159.59 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.2739 per therm
	All over 1000 therms per 30 day month at $0.1897 per therm
Summer Period:	First 1000* therms per 30 day month at $0.2155 per therm
	All over 1000 therms per 30 day month at $0.1192 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE
CLASSIFICATION NO. G-53

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge ;

Customer Charge Per Meter:	$23.4937 per day or $704.81 per 30 day month
Winter Period:	All therms per 30 day month at $0.1741 per therm
Summer Period:	All therms per 30 day month at $0.0835 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE
CLASSIFICATION NO. G-54

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$23.4937 per day or $704.81 per 30 day month
Winter Period:	All therms per 30 day month at $0.0667 per therm
Summer Period:	All therms per 30 day month at $0.0362 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-55

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-51.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097 per day or $72.29 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.4498 per therm
	All over 100 therms per 30 day month at $0.2678 per therm
Summer Period:	First 100* therms per 30 day month at $0.4498 per therm
	All over 100 therms per 30 day month at $0.2678 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions
Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-51.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE
CLASSIFICATION NO. G-56

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-52.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$6.9157 per day or $207.47 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.3561 per therm
	All over 1000 therms per 30 day month at $0.2466 per therm
Summer Period:	First 1000* therms per 30 day month at $0.2802 per therm
	All over 1000 therms per 30 day month at $0.1550 per therm

***The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this

schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-52.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFCATION NO. G-57

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-53.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge ;

Customer Charge Per Meter:	$30.5417 per day or $916.25 per 30 day month
Winter Period:	All therms per 30 day month at $0.2263 per therm
Summer Period:	All therms per 30 day month at $0.1086 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer

in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-53.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

20 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-58

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-54.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$30.5417 per day or $916.25 per 30 day month
Winter Period:	All therms per 30 day month at $0.0867 per therm
Summer Period:	All therms per 30 day month at $0.0471 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer

in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-54.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

21 OUTDOOR GAS LIGHTING

Availability

This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services. Service under this rate is available at those locations which were receiving service hereunder as of July 1, 2015, and which have continuously received service hereunder since that date.

Rate Per Light Per Month	$11.34

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

22 FIRM RATE SCHEDULES

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$21.50			$ 21.50	$ 21.50			$ 21.50
All therms	$ 0.2446	$ 0.4002	$ 0.0640	$ 0.7088	$ 0.2446	$ 0.4368	$ 0.0640	$ 0.7454
Residential Heating - R-3								
Customer Charge per Month per Meter	$25.50			$ 25.50	$ 25.50			$ 25.50
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.5201	$ 0.4002	$ 0.0640	$ 0.9843	$ 0.5201	$ 0.4368	$ 0.0640	$ 1.0209
All therms over the first block per month at	$ 0.4176	$ 0.4002	$ 0.0640	$ 0.8818	$ 0.4176	$ 0.4368	$ 0.0640	$ 0.9184
Residential Heating - R-4								
Customer Charge per Month per Meter	$10.20			$ 10.20	$ 10.20			$ 10.20
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2080	$ 0.4002	$ 0.0640	$ 0.6722	$ 0.2080	$ 0.4368	$ 0.0640	$ 0.7088
All therms over the first block per month at	$ 0.1670	$ 0.4002	$ 0.0640	$ 0.6312	$ 0.1670	$ 0.4368	$ 0.0640	$ 0.6678
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$55.61			$ 55.61	$ 55.61			$ 55.61
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.5689	$ 0.3961	$ 0.0450	$ 1.0100	$ 0.5689	$ 0.4206	$ 0.0450	$ 1.0345
All therms over the first block per month at	$ 0.3130	$ 0.3961	$ 0.0450	$ 0.7541	$ 0.3130	$ 0.4206	$ 0.0450	$ 0.7786
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$159.59			$ 159.59	$ 159.59			$ 159.59
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4458	$ 0.3961	$ 0.0450	$ 0.8869	$ 0.4458	$ 0.4206	$ 0.0450	$ 0.9114
All therms over the first block per month at	$ 0.2952	$ 0.3961	$ 0.0450	$ 0.7363	$ 0.2952	$ 0.4206	$ 0.0450	$ 0.7608
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$684.87			$ 684.87	$ 684.87			$ 684.87
All therms over the first block per month at	$ 0.2684	$ 0.3961	$ 0.0450	$ 0.7095	$ 0.1227	$ 0.4206	$ 0.0450	$ 0.5883
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$55.61			$ 55.61	$ 55.61			$ 55.61
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.3460	$ 0.4145	$ 0.0450	$ 0.8055	$ 0.3460	$ 0.4574	$ 0.0450	$ 0.8484
All therms over the first block per month at	$ 0.2060	$ 0.4145	$ 0.0450	$ 0.6655	$ 0.2060	$ 0.4574	$ 0.0450	$ 0.7084
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$159.59			$ 159.59	$ 159.59			$ 159.59
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2739	$ 0.4145	$ 0.0450	$ 0.7334	$ 0.2155	$ 0.4574	$ 0.0450	$ 0.7179
All therms over the first block per month at	$ 0.1897	$ 0.4145	$ 0.0450	$ 0.6492	$ 0.1192	$ 0.4574	$ 0.0450	$ 0.6216
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$704.81			$ 704.81	$ 704.81			$ 704.81
All therms over the first block per month at	$ 0.1741	$ 0.4145	$ 0.0450	$ 0.6336	$ 0.0835	$ 0.4574	$ 0.0450	$ 0.5859
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$704.81			$ 704.81	$ 704.81			$ 704.81
All therms over the first block per month at	$ 0.0667	$ 0.4145	$ 0.0450	$ 0.5262	$ 0.0362	$ 0.4574	$ 0.0450	$ 0.5386

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

23 FIRM RATE SCHEDULES - MANAGED EXPANSION PROGRAM

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate
Residential Non Heating - R-5								
Customer Charge per Month per Meter	$27.95			$ 27.95	$ 27.95			$ 27.95
All therms	$ 0.3180	$ 0.4002	$ 0.0640	$ 0.7822	$ 0.3180	$ 0.4368	$ 0.0640	$ 0.8188
Residential Heating - R-6								
Customer Charge per Month per Meter	$33.15			$ 33.15	$ 33.15			$ 33.15
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.6761	$ 0.4002	$ 0.0640	$ 1.1403	$ 0.6761	$ 0.4368	$ 0.0640	$ 1.1769
All therms over the first block per month at	$ 0.5429	$ 0.4002	$ 0.0640	$ 1.0071	$ 0.5429	$ 0.4368	$ 0.0640	$ 1.0437
Residential Heating - R-7								
Customer Charge per Month per Meter	$13.26			$ 13.26	$ 13.26			$ 13.26
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2704	$ 0.4002	$ 0.0640	$ 0.7346	$ 0.2704	$ 0.4368	$ 0.0640	$ 0.7712
All therms over the first block per month at	$ 0.2171	$ 0.4002	$ 0.0640	$ 0.6813	$ 0.2171	$ 0.4368	$ 0.0640	$ 0.7179
Commercial/Industrial - G-44								
Customer Charge per Month per Meter	$72.29			$ 72.29	$ 72.29			$ 72.29
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.7396	$ 0.3961	$ 0.0450	$ 1.1807	$ 0.7396	$ 0.4206	$ 0.0450	$ 1.2052
All therms over the first block per month at	$ 0.4069	$ 0.3961	$ 0.0450	$ 0.8480	$ 0.4069	$ 0.4206	$ 0.0450	$ 0.8725
Commercial/Industrial - G-45								
Customer Charge per Month per Meter	$207.47			$ 207.47	$ 207.47			$ 207.47
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.5795	$ 0.3961	$ 0.0450	$ 1.0206	$ 0.5795	$ 0.4206	$ 0.0450	$ 1.0451
All therms over the first block per month at	$ 0.3838	$ 0.3961	$ 0.0450	$ 0.8249	$ 0.3838	$ 0.4206	$ 0.0450	$ 0.8494
Commercial/Industrial - G-46								
Customer Charge per Month per Meter	$890.33			$ 890.33	$ 890.33			$ 890.33
All therms over the first block per month at	$ 0.2684	$ 0.3961	$ 0.0450	$ 0.7095	$ 0.1595	$ 0.4206	$ 0.0450	$ 0.6251
Commercial/Industrial - G-55								
Customer Charge per Month per Meter	$72.29			$ 72.29	$ 72.29			$ 72.29
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.4498	$ 0.4145	$ 0.0450	$ 0.9093	$ 0.4498	$ 0.4574	$ 0.0450	$ 0.9522
All therms over the first block per month at	$ 0.2678	$ 0.4145	$ 0.0450	$ 0.7273	$ 0.2678	$ 0.4574	$ 0.0450	$ 0.7702
Commercial/Industrial - G-56								
Customer Charge per Month per Meter	$207.47			$ 207.47	$ 207.47			$ 207.47
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.3561	$ 0.4145	$ 0.0450	$ 0.8156	$ 0.2802	$ 0.4574	$ 0.0450	$ 0.7826
All therms over the first block per month at	$ 0.2466	$ 0.4145	$ 0.0450	$ 0.7061	$ 0.1550	$ 0.4574	$ 0.0450	$ 0.6574
Commercial/Industrial - G-57								
Customer Charge per Month per Meter	$916.25			$ 916.25	$ 916.25			$ 916.25
All therms over the first block per month at	$ 0.2263	$ 0.4145	$ 0.0450	$ 0.6858	$ 0.1086	$ 0.4574	$ 0.0450	$ 0.6110
Commercial/Industrial - G-58								
Customer Charge per Month per Meter	$916.25			$ 916.25	$ 916.25			$ 916.25
All therms over the first block per month at	$ 0.0867	$ 0.4145	$ 0.0450	$ 0.5462	$ 0.0471	$ 0.4574	$ 0.0450	$ 0.5495

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24 FIRM RATE SCHEDULES - OUTDOOR GAS LIGHTING

Outdoor Gas Lighting	
Per Light Per Month	$11.34

25 ANITCIPATED COST OF GAS

Anticipated Cost of Gas

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 7,527,898	
Supply Costs:	49,523,042	
Storage Gas:		
Demand, Capacity:	$ 941,660	
Commodity Costs:	4,026,000	
Produced Gas:	1,797,499	
Hedged Contract (Saving)/Loss	-	
Hedge Underground Storage Contract (Saving)/Loss	-	
Unadjusted Anticipated Cost of Gas		$ 63,816,099
Adjustments:		
Prior Period (Over)/Under Recovery (as of 05/01/15)	$ 2,690,610	
Interest	14,641	
Prior Period Adjustments	-	
Broker Revenues	(1,374,947)	
Refunds from Suppliers	-	
Fuel Financing	-	
Transportation CGA Revenues	(29,471)	
Interruptible Sales Margin	-	
Capacity Release and Off System Sales Margins	(5,448,856)	
Hedging Costs	-	
Fixed Price Option Administrative Costs	41,972	
Total Adjustments		(4,106,050)
Total Anticipated Direct Cost of Gas		$ 59,710,049
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Unadjusted Anticipated Cost of Gas 11/01/15 - 04/30/16	$ 63,816,099	
Working Capital Rate: Lead Lag Days / 365	0.0391	
Prime Rate	3.50%	
Working Capital Percentage	0.137%	
Working Capital	$ 87,342	
Plus: Working Capital Reconciliation (Acct 142.20)	(33,597)	
Total Working Capital Allowance		53,745
Bad Debt:		
Total Unadjusted Anticipated Cost of Gas 11/01/15 - 04/30/16	$ 63,816,099	
Less: Refunds	-	
Plus: Total Working Capital	53,745	
Plus: Prior Period (Over)/Under Recovery	2,690,610	
Subtotal	$ 66,560,454	
Bad Debt Percentage	4.04%	
Bad Debt Allowance	$ 2,689,042	
Plus: Bad Debt Reconciliation (Acct 175.52)	(37,241)	
Total Bad Debt Allowance		$ 2,651,801
Production and Storage Capacity		$ 1,980,428
Miscellaneous Overhead (11/01/15 - 04/30/16)	$ 13,170	
Times Winter Sales	90,536	
Divided by Total Sales	112,609	
Miscellaneous Overhead		10,589
Total Anticipated Indirect Cost of Gas		$ 4,696,563
Total Cost of Gas		$ 64,406,611

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26 CALCULATION OF FIRM SALES COST OF GAS RATE

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas		$ 59,710,049		
Projected Prorated Sales (11/01/16 - 04/30/17)		89,920,078		
Direct Cost of Gas Rate			$ 0.6640	per therm
Demand Cost of Gas Rate		$ 8,469,558	$ 0.0942	per therm
Commodity Cost of Gas Rate		55,346,541	$ 0.6155	per therm
Adjustment Cost of Gas Rate		(4,106,050)	$ (0.0457)	per therm
Total Direct Cost of Gas Rate		$ 59,710,049	$ 0.6640	per therm
Total Anticipated Indirect Cost of Gas		$ 4,696,563		
Projected Prorated Sales (11/01/16 - 04/30/17)		89,920,078		
Indirect Cost of Gas			$ 0.0522	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/16			**$ 0.7162**	**per therm**

RESIDENTIAL COST OF GAS RATE - 11/01/16	**COGwr**	**$ 0.7162**	**/therm**
Change in rate due to change in under/over recovery		**$ (0.0723)**	
RESIDENTIAL COST OF GAS RATE - 12/01/2016	**COGsr**	**$ 0.6439**	**/therm**
Change in Rate due to change in under/over recovery		**$ 0.0837**	
RESIDENTIAL COST OF GAS RATE - 01/01/2017	**COGwr**	**$ 0.7276**	**/therm**
Change in Rate due to change in under/over recovery		**$ (0.1264)**	
RESIDENTIAL COST OF GAS RATE - 2/1/2017	**COGwr**	**$ 0.6012**	**/therm**
Change in Rate due to change in under/over recovery		**$ (0.1171)**	
RESIDENTIAL COST OF GAS RATE - 3/1/2017	**COGwr**	**$ 0.4841**	**/therm**
Maximum	(COG + 25%)	$ 0.8953	

C&I LOW WINTER USE COST OF GAS RATE - 11/01/16	**COGwl**	**$ 0.7305**	**/therm**
Change in rate due to change in under/over recovery		**$ (0.0723)**	
C&I LOW WINTER USE COST OF GAS RATE - 12/01/2016	**COGsl**	**$ 0.6582**	**/therm**
Change in Rate due to change in under/over recovery		**$ 0.0837**	
C&I LOW WINTER USE COST OF GAS RATE - 01/01/2017	**COGsl**	**$ 0.7419**	**/therm**
Change in Rate due to change in under/over recovery		**$ (0.1264)**	
C&I LOW WINTER USE COST OF GAS RATE - 2/01/2017	**COGsl**	**$ 0.6155**	**/therm**
Change in Rate due to change in under/over recovery		**$ (0.1171)**	
C&I LOW WINTER USE COST OF GAS RATE - 3/01/2017	**COGsl**	**$ 0.4984**	**/therm**

Average Demand Cost of Gas Rate Effective 11/01/16	$ 0.0942		
Times: Low Winter Use Ratio (Winter)	1.1637	Maximum (COG + 25%)	$ 0.9131
Times: Correction Factor	0.9898		
Adjusted Demand Cost of Gas Rate	$ 0.1085		
Commodity Cost of Gas Rate	$ 0.6155		
Adjustment Cost of Gas Rate	$ (0.0457)		
Indirect Cost of Gas Rate	$ 0.0522		
Adjusted C&I Low Winter Use Cost of Gas Rate	$ 0.7305		

C&I HIGH WINTER USE COST OF GAS RATE - 11/01/16	**COGwh**	**$ 0.7121**	**/therm**
Change in rate due to change in under/over recovery		**$ (0.0723)**	
C&I HIGH WINTER USE COST OF GAS RATE - 12/01/2016	**COGsh**	**$ 0.6398**	**/therm**
Change in Rate due to change in under/over recovery		**$ 0.0837**	
C&I HIGH WINTER USE COST OF GAS RATE - 01/01/2017	**COGwh**	**$ 0.7235**	**/therm**
Change in Rate due to change in under/over recovery		**$ (0.1264)**	
C&I HIGH WINTER USE COST OF GAS RATE - 2/01/2017	**COGwh**	**$ 0.5971**	**/therm**
Change in Rate due to change in under/over recovery		**$ (0.1171)**	
C&I HIGH WINTER USE COST OF GAS RATE - 3/01/2017	**COGwh**	**$ 0.4800**	**/therm**

Average Demand Cost of Gas Rate Effective 11/01/16	$ 0.0942		
Times: High Winter Use Ratio (Winter)	0.9667	Maximum (COG + 25%)	$ 0.8901
Times: Correction Factor	0.9898		
Adjusted Demand Cost of Gas Rate	$ 0.0901		
Commodity Cost of Gas Rate	$ 0.6155		
Adjustment Cost of Gas Rate	$ (0.0457)		
Indirect Cost of Gas Rate	$ 0.0522		
Adjusted C&I High Winter Use Cost of Gas Rate	$ 0.7121		

27 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE

II. RATE SCHEDULES			
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE			
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017			
(Refer to Text in Section 17(A) Fixed Price Option Program)			
(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$ 59,710,049		
Projected Prorated Sales (11/01/16 - 04/30/17)	89,920,078		
Direct Cost of Gas Rate		$ 0.6640	per therm
Demand Cost of Gas Rate	$ 8,469,558	$ 0.0942	per therm
Commodity Cost of Gas Rate	55,346,541	$ 0.6155	per therm
Adjustment Cost of Gas Rate	(4,106,050)	$ (0.0457)	per therm
Total Direct Cost of Gas Rate	$ 59,710,049	$ 0.6640	per therm
Total Anticipated Indirect Cost of Gas	$ 4,696,563		
Projected Prorated Sales (11/01/16 - 04/30/17)	89,920,078		
Indirect Cost of Gas		$ 0.0522	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/16) as updated, see page 77		**$ 0.7162**	
<u>Calculation of FPO - Consistent with Order No. 24,515 in DG 05-127</u>			
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/16) as originally filed 9-1-16		**$ 0.7068**	
FPO Risk Premium		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE (11/01/16)		**$ 0.7268**	
RESIDENTIAL COST OF GAS RATE - 11/01/16	**COGwr**	**$ 0.7268**	**/therm**

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28 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE – KEENE DIVISION

Period Covered:	Winter Period November 1, 2014, through April 30, 2015		
Projected Gas Sales - therms			1,076,725
Total Anticipated Cost of Propane Sendout			$1,826,090
Add:	Prior Period Deficiency Uncollected	$9,404	
	Interest	$2,382	
Deduct:	Prior Period Excess Collected	$0	
	Interest	$0	
	Prior Period Adjustments and Interest		$11,786
Total Anticipated Cost			$1,837,876
Cost of Gas Rate			
Non-Fixed Price Option Cost of Gas Rate (per therm)			$1.7069
Fixed Price Option Premium			$0.0200
Fixed Price Option Cost of Gas Rate (per therm)			$1.7269
Non-Fixed Price Option Cost of Gas Rate - Beginning Period (per therm)			$1.7069
Mid Period Adjustment - December 1, 2014			($0.2427)
Mid Period Adjustment - January 1, 2015			($0.0718)
Revised Non-Fixed Price Option Cost of Gas Rate - Effective January 1, 2015 (per therm)			$1.3924
Pursuant to tariff section 17(d), the Company may adjust the approved cost of gas rate upward on a monthly basis to the following rate:			
Maximum Cost of Gas Rate - Non-Fixed Price Option (per therm)			$2.1336

29 CALCULATION OF FIRM TRANSPORTATION COST OF GAS RATE

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	(Col 2)		(Col 3)		(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:					
PROPANE	$ 283,609				
LNG	1,513,890				
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	1,797,499				
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	9.9%				
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	$ 177,952				
PROJECTED FIRM THROUGHPUT (THERMS):					
FIRM SALES	90,536,024		64.4%		
FIRM TRANSPORTATION SUBJECT TO FTCG	50,086,696		35.6%		
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	140,622,721		100.0%		
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	35.6%	x	$ 177,952	=	$ 63,383
PRIOR (OVER) OR UNDER COLLECTION					(33,912)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS					$ 29,471
PROJECTED FIRM TRANSPORTATION THROUGHPUT					50,086,696
FIRM TRANSPORTATION COST OF GAS					$0.0006

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30 ENVIRONMENTAL SURCHARGE – MANUFACTURED GAS PLANTS

Environmental Surcharge - Manufactured Gas Plants		
Manufactured Gas Plants		
Required annual Environmental increase	$2,893,504	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,893,504	
Overall Annual Net Increase to Rates	$2,893,504	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/17 - sales and transportation	186,909,214	therms
Surcharge per therm	$0.0155	per therm
Total Environmental Surcharge	$0.0155	

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31 RATE CASE EXPENSE FACTOR CALCULATION

	Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities	
	Local Distribution Adjustment Charge (LDAC) decrease due to Rate Case Expense and Recoupment	
	For LDAC effective November 1, 2016 - December 31, 2016	
	Docket No. DG 14-180	
1	August 1, 2016 Balance of Acct. 8840-2-0000-10-1930-1745	$46,132
2	Estimated August 2016 - October 2016 Recovery	($292,028)
3	Estimated August 2016 - October 2016 Interest	($761)
4		
5	Estimated Balance November 1, 2016	($246,658)
6	Estimated November 2016 - December 2016 Interest	($791)
7		
8	Estimated Remaining Recovery	($247,449)
9		
10	Estimated November 2016 - December 2016 Sales (therms)	34,894,997
11		
12	RCE rate per therm November 2016 - December 2016	($0.0071)

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32 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION

Local Delivery Adjustment Clause Calculation

		Sales Customers	Transportation Customers	
Residential Non Heating Rates - R-1, R-5				
Energy Efficiency Charge	$0.0402			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0402		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0016		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0067		
LDAC		**$0.0640**		**per therm**
Residential Heating Rates - R-3, R-4, R-6, R-7				
Energy Efficiency Charge	$0.0402			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0402		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0016		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0067		
LDAC		**$0.0640**		**per therm**
Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**
Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57,G-58				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**

III. DELIVERY TERMS AND CONDITIONS

1 RATES AND CHARGES

1.1 The Company shall apply this tariff on a non-discriminatory and non-preferential basis to all Customers who obtain service from the Company, except as this tariff is explicitly modified by order of the NHPUC. The provisions of Part III Section 20 of this tariff will specifically apply to all entities designated by the Customer as set forth in Section 20.5 to supply Gas to a Designated Receipt Point for the Customer's account.

1.2 The Company reserves the right to impose reasonable fees and charges pursuant to the various provisions of this tariff.

1.3 In the event that the Company incurs minimum bill, inventory, transition, take or pay, imbalance, or any other charges associated with the provision of Delivery Service to Customers, the Company may impose an additional charge on the Suppliers serving said Customers as approved by the NHPUC.

2 DEFINITIONS

Adjusted Target Volume ("ATV)	The volume of Gas determined by the Company using a Consumption Algorithm and required to be nominated and delivered each Gas Day by the Supplier on behalf of Customers taking non-daily metered Delivery Service.
Aggregation Pool	One or more Customer accounts whose Gas Usage is served by the same Supplier and aggregated pursuant to Section 20.6 of this tariff for operational purposes, including but not limited to nominating, scheduling, and balancing Gas deliveries to Designated Receipt Point(s) within the associated Gas Service Area.
Annual Reassignment Date	Five (5) Business Days prior to November 1 of each year when the Company reassigns Capacity to Suppliers pursuant to Section 11.6 of this tariff.
Assignment Date	Five (5) Business Days prior to the first Gas Day of each month when the Company assigns Capacity to Suppliers pursuant to Section 11.4 of this tariff.
Authorization Number	A number unique to the Customer generated by the Company and printed on the Customer's bill that the Customer must furnish to the Supplier to enable the Supplier to obtain the Customer's Gas Usage information pursuant to Section 20.4, and to initiate or terminate Supplier Service as set forth in Section 20.5 of this tariff.
Btu	One British thermal unit; i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit.
Business Day	Monday through Friday excluding holidays recognized by the Company. Where relevant, a Business Day shall consist of the hours during which the Company is open for business with the public. ***If any performance date referenced in this Tariff is not a Business Day, such performance shall be the next succeeding Business Day***.
Capacity	Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity as defined in this tariff.

Capacity Allocators	The estimated proportions of the Customer's Total Capacity Quantity that comprise Pipeline Capacity, Storage Withdrawal Capacity and Peaking Capacity.
Capacity Mitigation Service	The service available to Suppliers in accordance with Section 11.10.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Commodity	See Gas.
Company	Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Company Gas Allowance	The difference between the sum of all amounts of Gas received into the Company's distribution system (including Gas produced by the Company) and the sum of all amounts of Gas delivered from the Company's distribution system divided by said amount of Gas received. Such difference shall include but not be limited to Gas consumed by the Company for its own purposes, line losses, and Gas vented and lost as a result of force majeure, excluding Gas otherwise accounted for.
Company-Managed Supplies	Capacity and Supply contracts held and managed by the Company and made available to the Supplier pursuant to Section 11.9 of this tariff including Supply-sharing contracts and load-management contracts.
Consumption Algorithm	A mathematical formula used to estimate a Customer's daily consumption.
Critical Day	In accordance with Section 16 of this tariff, a day declared at any time by the Company in its reasonable discretion when unusual operating conditions may jeopardize operation of the Company's distribution system.
Customer	The recipient of Delivery Service whose Gas Usage is recorded by a meter or group of meters at a specific location and who is a customer of record of the Company.
Daily Baseload	The Customer's average usage per Gas Day that is assumed to be unrelated to weather.
Daily Index	The mid-point of the range of prices as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)". In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of Gas as the basis for this calculation until such time that the NHPUC approves a suitable replacement.
Dekatherm	Ten Therms.
Delivery Point	The interconnection between the Company's facilities and the Customer's facilities.
Delivery Service	The distribution of Gas by the Company on any Gas Day from the Designated Receipt Point to the Customer's Delivery Point and related Customer services.
Design Peak Season	The forecasted Peak Season during which the Company's system experiences the highest aggregate Gas Usage.

Designated Receipt Point	For each Customer, the Company designated interconnection between a Transporting Pipeline and the Company's distribution facilities at which point, or such other point as the Company may designate from time to time for operational purposes, the Supplier will make deliveries of Gas for the Customer's account.
Designated Representative	The designated representative of the Customer, who shall be authorized to act for, and conclusively bind, the Customer regarding Delivery Service in accordance with the provisions of Section 21 of this tariff.
Gas	Natural Gas that is received by the Company from a Transporting Pipeline at the Designated Receipt Point and delivered by the Company to the Delivery Point for the Customer's account. In addition, the term shall include amounts of vaporized liquefied natural Gas and/or propane-air vapor that are introduced by the Company into its system and made available to the Customer as the equivalent of natural Gas that the Customer is otherwise entitled to have delivered by the Company.
Gas Day	A period of twenty-four (24) consecutive hours beginning at 10:00 a.m., E.T., and ending at 10:00 a.m., E.T., the next calendar day, or other such hours used by the Transporting Pipeline.
Gas Service Area	An area within the Company's distribution system as defined in Section 4 of this tariff, for the purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools.
Gas Usage	The actual quantity of Gas used by the Customer as measured by the Company's metering equipment at the Delivery Point.
Heating Degree Day	A measure used to estimate weather-sensitive Gas consumption calculated by subtracting the average temperature for each day from the number 65. Each degree day that represents a degree below 65 is considered a Heating Degree Day.
Heating Factor	The Customer's estimated weather-sensitive Gas consumption per Heating Degree Day.
MMBtu	One million Btus.
Maximum Daily Peaking	The portion of a Customer's Total Capacity Quantity identified
Quantity ("MDPQ")	and allocated as Peaking Capacity, such that the maximum daily amount of Gas that can be withdrawn from a Supplier's Peaking Service Account pursuant to Section 14 of this tariff shall be equal to the sum of the MDPQs for all Customers in that Supplier's Aggregation Pool.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Index numbers for all Gas Days in a Month.
NHPUC	The New Hampshire Public Utilities Commission.
Nomination	The notice given by the Supplier to the Company that specifies, in accordance with the Standard Nomination Form attached as Attachment A, an intent to deliver a quantity of Gas to the Designated Receipt Point(s) on behalf of one or more Customers, including the volume to be received, the Designated

	Receipt Point(s), the Transporting Pipeline, the delivering contract(s), the shipper, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months of May to October, inclusive.
Operational Flow Order ("OFO")	The Company's instructions to the Supplier to take such action as conditions require including, but not limited to, diverting Gas to or from the Company's distribution system pursuant to Section 16 of this tariff.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage.
Peak Season	The consecutive months of November to April, inclusive.
Peaking Capacity	Capacity in addition to upstream pipeline and underground storage Capacity normally used by the Company to meet daily requirements during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Service	A Company-managed resource consisting of Peaking Capacity and Peaking Supply.
Peaking Service Account	An account whose balance indicates the total volumes of Peaking Service resources available to a Supplier, where the maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to this tariff.
Peaking Service Rule Curve	A system of operational parameters associated with the use of the Company's Peaking Capacity including, but not limited to, indicators of the necessary levels of Peaking Supply that must be maintained in Suppliers' Peaking Service Accounts in order for the Company to meet system demands under Design Peak Season conditions. The Company will communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Peaking Service Rule Curve as identified in Section 14 of this tariff.
Peaking Supply	The aggregate amount of Supply in excess of upstream pipeline and underground storage Supply required to meet the Company's forecasted Supply needs during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Supply Allocator	An allocation factor that represents the proportion of a Customer's estimated Gas Usage during the Design Peak Season that is generally served with Peaking Service supplies.
Pipeline Capacity	Transportation capacity on interstate pipeline systems normally used for deliveries of Gas to the Company's city gates, exclusive of Storage Withdrawal Capacity.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the method allocation of discrepancies in confirmed Nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier Service Agreement.
Rate Schedule	The schedule of rates included in this tariff.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.

Sales Service	Commodity service provided on a firm basis to a Customer who is not receiving Supplier Service, in accordance with the provisions set forth in this tariff. The provision of Sales Service shall be the responsibility of the Company and shall be provided to the Customer by the Company or its designated Supplier pursuant to law or regulation.
Seasonal Storage Capacity	Contracts for Capacity in off-system storage facilities used to accumulate and maintain Gas inventories for re-delivery to the Company's city gates normally during the Peak Season.
Storage Withdrawal Capacity	Capacity for the withdrawal of Gas inventories maintained in off-system storage facilities, as well as the Pipeline Capacity used to deliver such Gas to the Company's city gates.
Supplier	Any entity that has met the Company's requirements set forth in Section 20 of this tariff and that has been designated by a Customer to supply Gas to a Designated Receipt Point for the Customer's account; provided, however, that a Customer may act as its own Supplier in accordance with Section 5.2 of this tariff.
Supplier Service	The sale of Gas to a Customer by a Supplier.
Supplier Service Agreement	An agreement, substantially in the form set forth in Attachment A, which must be executed by the Company and a Supplier in order for the Supplier to serve Customers on the Company's system.
Supply	See Gas.
Therm	An amount of Gas having a thermal content of 100,000 Btus.
Total Capacity Quantity	The total amount of Capacity assignable to a Supplier on behalf
("TCQ")	of a Customer.
Transporting Pipeline	The interstate pipeline company that transports and delivers Gas to the Designated Receipt Point.

3 CHARACTER OF SERVICE

3.1 All rates within Part II Rate Schedule are predicated upon service to a Customer at a single Delivery Point and metering installation, except as otherwise specifically provided by a given rate. Where service is supplied to a Customer at more than one Delivery Point or metering installation, each single Delivery Point or metering installation shall be considered to be a separate Customer for purposes of applying the Rate Schedule, except when a Customer is served through multiple points of delivery or metering installations for the Company's own convenience.

3.2 The Company may refuse to supply service to loads of unusual characteristics which, in its sole reasonable judgment, might adversely affect the quality of service supplied to other Customers, the public safety or the safety of the Company's personnel. In lieu of such refusal, the Company may require a Customer to install any necessary regulating and protective equipment in accordance with the requirements and specifications of the Company.

4 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS

4.1 There shall be 1 Gas Service Area defined for purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools pursuant to this tariff. Each such Gas Service Area shall be defined to include the municipalities listed within each such Gas Service Area, as follows:

(1) Area 1: Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities.
The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelahm, Pembroke, Sanbornton, Tilton, Windham, and part of Canterbury.

4.2 For each Aggregation Pool as set forth by Section 20.6, the Company will designate at least one specific interconnection between a Transporting Pipeline and the Company's distribution facilities, at which point, or such other point as the Company may designate from time to time, the Supplier will make deliveries for the Aggregation Pool. The interconnections that the Company may assign as the Customer's Designated Receipt Point for the Aggregation Pool are as follows:

(1) *Name Transporting Pipeline: Tennessee Gas Pipeline*
Names of City Gates/Meter Numbers:

Nashua/Milford	#020132
Manchester	#020133
Hooksett	#020254
Concord/Laconia	#020426
Suncook	#020451
Londonderry	#020632

(2) *Name Transporting Pipeline: Portland Natural Gas Transmission System*
Names of City Gates/Meter Number

Berlin	#020260

5 CUSTOMER REQUEST FOR SERVICE FROM COMPANY

5.1 Application for Delivery Service, Sales Service, or any other service offered by the Company to a Customer will be received by any duly authorized representative or agent of the Company.

5.2 Before any service from the Company may commence, the Customer must request such service. A Customer applying for Delivery Service only must also arrange for Supplier Service with a Supplier pursuant to Section 20. A Customer may act as its own Supplier provided it meets all of the Supplier requirements delineated in Section 20.

6 QUALITY AND CONDITION OF GAS

6.1 Gas delivered to the Company by or for the Customer shall conform, in all respects, to the Gas quality standards of the Transporting Pipeline. All Gas tendered by a Supplier at a Designated Receipt Point shall be of merchantable quality and shall be interchangeable with Gas purchased by the Company from its Suppliers. The Company reserves the right to refuse non-conforming Gas.

6.2 In no event shall the Company be obligated to accept and deliver any Gas that does not meet the quality standards of the Transporting Pipeline.

6.3 The Company reserves the right to commingle Gas tendered by a Supplier at a Designated Receipt Point with other Gas, including liquefied natural Gas and propane-air vapor.

6.4 Gas tendered by a Supplier at a Designated Receipt Point will be at a pressure sufficient to enter the Company's distribution system without requiring the Company to adjust its normal operating pressures to receive the Gas. The Company has no obligation to receive Gas at a pressure that exceeds the maximum allowable operating pressure of the Company's distribution system at the Designated Receipt Point.

7 POSSESSION OF GAS

7.1 Gas shall be deemed to be in the control and possession of the Company after such Gas is delivered to the Designated Receipt Point and until the Gas is delivered to the Customer at the Delivery Point. The Company shall not be responsible for the Gas when the Gas is not in the Company's control and possession.

7.2 The Company shall not be liable to the Supplier or the Customer for any loss arising from or out of Delivery Service, including loss of Gas in the possession of the Company or for any other cause, except for the negligence of the Company's own employees or agents.

8 COMPANY GAS ALLOWANCE

8.1 The amount of Gas tendered by the Supplier to the Designated Receipt Point will be reduced, upon delivery to the Customer's Delivery Point, by the Company Gas Allowance. The Company Gas Allowance shall be in effect from November 1 through October 31. Such adjustment shall be recalculated prior to the Company's Peak Season cost of Gas filing with the NHPUC.

9 DAILY METERED DELIVERY SERVICE

9.1 Applicability

Section 9 of this tariff shall be applicable in the following conditions:

9.1.1 All Customers whose service may be interrupted at any time during the year shall be required to take daily metered Delivery Service.

9.1.2 Any Customer, regardless of annual Gas Usage, may elect daily metered Delivery Service.

9.1.3 Customers under Rate Schedules G-43, G-46, G-53, G-54, G-57, and G-58 wishing to take Delivery Service are required to take Daily Metered Delivery Service. In addition, the Company may require a Customer to take daily metered Delivery Service if the Company determines that the daily Gas Usage characteristics of the Customer cannot be accurately modeled using the Company's Consumption Algorithm or if the volumes reasonably anticipated by the Company to be used by the Customer are of a size that may materially affect the integrity of the Company's distribution system.

9.2 Delivery Service Provided

This service provides delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day. For Customers taking Delivery Service under Rate Schedules ***G-43, G-46, G-53, G-54, G-57, and G-58*** this service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point.

9.3 Nominations and Scheduling of Service

9.3.1 The Supplier is responsible for nominating and delivering to the Designated Receipt Point(s) every Gas Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool plus the Company Gas Allowance in accordance with Section 8 of this tariff.

9.3.2 Nominations shall be communicated to the Company by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means.

9.3.3 Nominations for the first Gas Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month Nominations of the Transporting Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of Nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.4 The Supplier may make daily Nominations including, but not limited to, changes to existing Nominations, within a given Month no later than two (2) hours prior to the deadline for daily Nominations of the Transporting Pipeline for the Gas Day on which the Nomination is to be effective, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.5 The Supplier may make intra-Gas Day Nominations, including but not limited to changes to existing Nominations, within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis.

9.3.7 Nominations may be rejected, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Delivery Service in effect from time to time.

9.4 Determination of Receipts

9.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

9.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

9.5 Metering and Determination of Deliveries

9.5.1 The Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. Telemetering equipment shall remain the property of the Company at all times. The Company shall require each Customer to install and maintain, at the Customer's expense, reliable telephone lines and electrical connections that meet the Company's operating requirements. The Company may require the Customer to furnish a dedicated telephone line. If the Customer fails to maintain such telephone lines and electrical connections for fourteen (14) consecutive days after notification by the Company, the Company may discontinue service to the Customer.

9.5.2 Should a Customer or a Supplier request that additional telemetering equipment or a communication device be attached to the existing telemetering equipment in addition to that provided pursuant to Section 9.5.1, the Company shall install, test, and maintain the requested telemetering equipment or communication device; provided that such telemetering equipment or communication device does not interfere with the operation of the equipment required for the Company's purposes and otherwise meet the Company's requirements. The Customer or Supplier shall provide such telemetering equipment or communication device, unless the Company elects to do so. The Customer or Supplier shall bear the cost of providing and installing the telemetering equipment, communication device, or any other related equipment, and shall have electronic access to the Customer's Gas Usage information. Upon installation, the telemetering equipment or communication device shall become the property of the Company and will be maintained by the Company. The Company shall bill the Customer or Supplier after installation.

9.5.3 The Company shall complete installation of telemetering equipment and communication devices, if reasonably possible, within sixty (60) days of receiving a written request from the Customer or Supplier provided that the Customer completes the installation of any required telephone or electrical connections within ten (10) days of such request.

9.5.4 The Company may, at its sole discretion, bill the Customer on a calendar month or cycle month basis.

9.6 Balancing

9.6.1 The Supplier must maintain a balance between daily receipts and daily Gas Usage within the following tolerances:

Off-Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 15% of said receipts. The Supplier shall be charged 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 10% of said receipts. The Supplier shall be charged 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 102% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool exceeds 20% of said receipts [(Receipts - Usage) > (20% x Receipts)].

Critical Day That Will Be Aggravated by Over-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 120% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 5 times the Daily Index to the extent that the difference between the Supplier's actual receipts on the Transporting Pipeline to each Gas Service Area and the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 2% of said receipts [(Receipts - Usage > (2% x Receipts)].

Point Specific Balancing: In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

9.6.2 If the Supplier has an accumulated imbalance within a Month, the Supplier may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

9.6.3 In addition to the charges set forth in Section 9.6.1, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

9.6.4 If, as a result of the Company interrupting or curtailing service pursuant to Section 17 of this tariff, the Supplier incurs a daily imbalance penalty due to over delivery, the Company will waive such penalty for the First Day of the interruption or curtailment period. If the Company has issued notice of an interruption or curtailment in service and the Supplier is unable to change its Nomination, or if the Supplier's Gas has been delivered to the Designated Receipt Point, then the Company will credit such Gas against the Supplier's imbalance.

9.6.5 The Supplier will maintain a balance between receipts at the Designated Receipt Point(s) and the aggregated Gas Usage of Customers in each Aggregation Pool. If the Transporting

Pipeline posts notice on its electronic bulletin board that its customers will be required to adhere to a maximum hourly flow rate, the Supplier will be deemed to have notice that maximum hourly flows will be in effect on the Company's distribution facilities as of the same time and for the same period as maximum hourly flows are in effect on the Transporting Pipeline. The Supplier's maximum hourly flow will be established based on an allocation of even hourly flows of daily receipts of Gas scheduled in the relevant period in accordance with the applicable transportation tariff of the Transporting Pipeline. All Gas Usage in excess of the Supplier's maximum hourly flow rate shall be subject to an additional charge of 5 times the Daily Index for each Dekatherm in excess of the Supplier's maximum hourly flow. The Company will notify the Supplier of the Supplier's maximum hourly flow.

9.6.6 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the aggregated Gas Usage of Customers in the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, and storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

9.7 Cash Out

For each Aggregation Pool, the Supplier must maintain total Monthly receipts within a reasonable tolerance of total Monthly Gas Usage. Any differences between total Monthly receipts for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a percentage of total Monthly receipts, will be cashed out according to the following schedule:

Imbalance Tier	Over-deliveries	Under-deliveries
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month
> 5% ≤ 10%	0.85 times the above stated rate.	1.15 times the above stated rate.
> 10% ≤ 15%	0.60 times the above stated rate.	1.4 times the above stated rate.
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% under-delivery on a Transporting Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven (7) consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven (7) consecutive Daily Indices.

10 NON-DAILY METERED DELIVERY SERVICE

10.1 Applicability

Section 10 of this tariff applies to Customers taking Delivery Service under Rate Schedules G-41, G-42, G-51, G-52 and their Suppliers.

10.2 Delivery Service Provided

This service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day for Customers, without the requirement of recording Gas Usage at the Delivery Point on a daily basis. Daily Nominations are calculated by the Company on the basis of a Consumption Algorithm and the Supplier is obligated to deliver to the Designated Receipt Point(s) such quantities.

10.3 Nominations and Scheduling of Service

10.3.1 The Supplier is obligated to nominate and deliver the Adjusted Target Volume ("ATV"), as determined in Section 10.3.2, to the Designated Receipt Points on every Gas Day for each Aggregation Pool.

10.3.2 The Company shall determine the ATV for each Aggregation Pool of Customers taking non-daily metered Delivery Service for each Gas Day using a Consumption Algorithm. The ATV shall include the Company Gas Allowance. On each Business Day, the Company will communicate, electronically, by facsimile, or by other agreeable alternative means, the forecasted ATV to the Supplier for at least the subsequent four (4) Gas Days. The ATV in effect for any Gas Day shall be the most recent ATV for that Gas Day communicated to the Supplier by the Company. The ATV for a given Gas Day shall not be effective unless it has been communicated to the Supplier at least two (2) hours prior to the Company's Supplier Nomination deadline for that Gas Day, which shall be at least two (2) hours prior to the deadline for nominations on the Transporting Pipeline, or such lesser period as determined by the Company.

10.3.3 Nominations will be communicated to the Company electronically, by facsimile, or other agreeable alternative means.

10.3.4 Nominations for the first Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month nominations of the Delivering Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.5 The Supplier shall provide an intra-Month nomination no later than two (2) hours prior to the deadline of the Delivering Pipeline for the next Gas Day, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis. The Company will not confirm any volume nominated by the Supplier in excess of the ATV.

10.3.7 In the event that the Supplier is unable to deliver a confirmed ATV Nomination, the Supplier may make intra-Gas Day Nominations relating to changes to existing Nominations within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company; provided, however, that the Nomination must be in conformance with the requirements of and must be permitted by the Transporting Pipeline. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized by the Company for its own operations. The Company shall not adjust the ATV applied for the Gas Day.

10.3.8 Nominations may be rejected if they do not satisfy the conditions for Delivery Service in effect from time to time.

10.3.9 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an Operational Flow Order ("OFO") declared by the Company pursuant to Section 16 will be subject to the Critical Day provisions of Section 10.6.1 of this tariff, and the delivered quantity specified in the OFO will replace the ATV.

10.4 Determination of Receipts

10.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

10.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

10.5 Metering and the Determination of Deliveries

The Company shall record the Customer's Gas Usage at the Delivery Point by making actual meter reads on a monthly [or bi-monthly] basis. In the event that the Customer's Gas Usage is metered on a bi-monthly basis, the Company shall make available to the Supplier estimates of the Customer's Gas Usage for each of the two billing months.

10.6 Balancing

10.6.1 Any difference between the Supplier's ATV for an Aggregation Pool and the receipts on the Transporting Pipeline to the appropriate Designated Receipt Point(s) will be cashed out by the Company according to the following:

Off-Peak Season: For receipts less than the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Peak Season: For receipts less than the ATV but greater than or equal to 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts less than 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the first 5% difference, and the Supplier shall be charged two (2) times the Daily Index for the remaining difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day(s) The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged five (5) times the Daily Index for the difference between the ATV and actual receipts.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged the following amounts for all receipts in excess of the ATV:

(a) up to 25% in excess of the ATV, the Supplier shall be charged the Daily Index for the difference.

(b) for receipts in excess of 25% above the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day That Will Be Aggravated By Over-delivery.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.4 times the Daily Index for receipts greater than the ATV.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged the following amounts--for receipts less than the ATV but greater than or equal to 75% of the ATV, the Supplier shall be charged the Daily Index for the first 25% difference, and the Supplier shall be charged 1.1 times the Daily Index for the remaining difference.

10.6.2 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

10.6.3 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

10.6.4 In addition to the charges set forth in Sections 10.6.1 and 10.6.2, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

10.7 Cash Out

10.7.1 The Company shall use a daily cash out calculation to account for imbalances due to differences in forecast versus actual Heating Degree Days. Using a Consumption Algorithm, the Company will recalculate the ATV for each Aggregation Pool for each Gas Day of the Month, substituting actual Heating Degree Days for forecast Heating Degree Days. Daily recalculations shall be compared to the Aggregation Pool’s daily ATV, and the difference shall be cashed out at 100% of the Daily Index.

10.7.2 During the billing months of both June and December, the Company shall use a six-month cash-out calculation to account for differences in forecast usage versus billed Gas Usage. The Company may cash-out differences in forecast usage versus billed usage at intervals that are less than six months as provided by the Supplier Service Agreement.

(1) In the billing month of June, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of November 1 through April 30 to the sum of billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index weighted by actual Heating Degree Days over the same period. The Winter period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending April 30.

(2) In the billing month of December, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of May 1 through October 31 to the sum of the billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index over the same period. The Off-Peak period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending October 31.

10.7.3 The Company shall allow Suppliers to trade seasonal differences. Prior to the seasonal cash-out, the Company shall make available a list of Suppliers. Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company. All trades must be communicated to the Company within three (3) Business Days following receipt of the list.

10.7.4 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the ATVs of the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the Supplier's estimated maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

11 CAPACITY ASSIGNMENT

11.1 Applicability

Section 11 of this tariff applies to all Suppliers that have enrolled one or more Customers into one or more Aggregation Pools and shall include Customers acting as their own Supplier. The Company shall assign and the Supplier shall accept each Customer's pro-rata share of Capacity, if any, as established in accordance with this Section.

11.2 Identification of Capacity for Assignment

11.2.1 On or before September 15 of each year, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Capacity to be made available for assignment to Suppliers on each of twelve Assignment Dates beginning in October.

11.2.2 The Company shall identify, by Gas Service Area, the specific contracts and resources for assignment to Suppliers based on the Company's Capacity and resource plans. Such identified contracts and resources shall be used to determine the pro-rata shares of Capacity assignable to a Supplier on behalf of the Customers enrolled in its Aggregation Pool.

11.2.3 Capacity assigned by the Company may include Company-Managed Supplies that effectuate, at maximum tariff rates, the assignment of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)] and other contracts that are not assignable to third-parties due to governing tariffs.

11.3 Determination of Pro-Rata Shares of Capacity

11.3.1 The Company shall establish a Total Capacity Quantity ("TCQ") for each Customer taking Delivery Service. The TCQ represents the total amount of Capacity assignable to a Supplier on behalf of a Customer.

11.3.2 For a Customer receiving Sales Service on or after March 14, 2000, the TCQ shall be the Customer's estimated Gas Usage on the Peak Day as determined by the Company each October prior to the Customer's enrollment into Supplier Service. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during the Reference Period, or the best estimates available to the Company should actual Gas Usage information be partially or wholly unavailable.

11.3.3 For a Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had an executed contract for firm transportation service (i.e., the equivalent of Delivery Service) on file with the Company on or before March 14, 2000, the TCQ shall be zero.

11.3.4 A Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had a written request on file with the Company on or before March 14, 2000 may elect for its Supplier to accept assignment of its pro-rata share of Capacity as determined by the Company in accordance with Section 11.2 and, subject to availability, as determined by the Company in its sole reasonable discretion. In order to make such election, the Customer must have submitted to the Company, on or before ten (10) days prior to the first Assignment Date prior to the original effective date of this tariff, a completed application for Capacity that is signed by both the Customer and Supplier. All assignments of Capacity made on behalf of such electing Customer shall be executed in accordance with Sections 11 and 14 of this tariff as if the Customer had been receiving Sales Service on or after March 14, 2000

11.3.5 For a new Customer taking Supplier Service as its initial service after March 14, 2000, the TCQ shall be zero except in cases where the Customer is a new Customer of record at a meter location where a former Customer of record received firm service from the Company any time during the preceding twenty-four (24) months, in which case the TCQ established by the Company for the former Customer shall become the TCQ for the new Customer. The Company may reduce said TCQ value for the new Customer, if, in its sole reasonable discretion, the Company determines that the old Customer's TCQ exceeds the new Customer's estimated future consumption on the Peak Day. In the event that Sales Service is provided at a new meter location for Gas Usage associated with new construction, the TCQ shall be zero, provided that the Customer initiates Supplier Service upon the completion of said new construction in accordance with Section 20.5 of this tariff

11.3.6 Once the Company establishes a TCQ for a Customer pursuant to this Section 11.3, it shall remain in effect for the purpose of determining the Customer's pro-rata shares of Capacity until such time that the Customer returns to Sales Service. The Company shall establish a new TCQ value for the Customer pursuant to Section 11.3.2 if the Customer again elects to take Supplier Service after returning to Sales Service, unless otherwise established herein..

11.3.7 The Company shall determine the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assignable to a Supplier on behalf of a Customer as the product of the Customer's TCQ times the applicable Capacity Allocators. The Capacity Allocators for each class of Customers billed under the Company's Rate Schedule shall be set forth annually in Attachment C to this tariff.

11.3.8 The Company shall determine the pro-rata share of Seasonal Storage Capacity assignable to a Supplier on behalf of a Customer consistent with the tariffs governing the associated Storage Withdrawal Capacity.

11.3.9 The Company shall determine the pro-rata shares of Peaking Supply assignable to a Supplier in accordance with Section 14 of this tariff.

11.4 Capacity Assignments

11.4.1 On each Assignment Date, the Company will assign to the Supplier the pro-rata shares of Capacity on behalf of each Customer as determined by the Company in accordance with Sections 11.2, 11.3 and 11.7.

11.4.2 The total amount of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assigned to the Supplier on behalf of the Customers in an Aggregation Pool shall be at least equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of Five (5) Business Days prior to the Assignment Date.

11.4.3 Storage Withdrawal Capacity shall be subject to Operational Flow Orders that are issued by the Company pursuant to Section 16 of this tariff, in the event that the Company requires the Supplier to deliver or to store quantities of Gas for the purposes of managing system imbalances and maintaining Delivery Service. Whenever the Company assigns incremental Storage Withdrawal Capacity to the Supplier, the Company shall also assign to that Supplier additional Seasonal Storage Capacity pursuant to Section 11.8.

11.4.4 The Peaking Capacity assigned to the Supplier shall establish the Maximum Daily Peaking Quantity ("MDPQ") for the Aggregation Pool in the Supplier's Service Agreement. In the event that the Company increases a Supplier's MDPQ, the Company shall also assign to that Supplier additional Peaking Supply pursuant to Section 14.

11.4.5 The Company shall execute Capacity assignments in increments of 200 MMBtus. The Supplier shall accept an initial increment of Capacity on the first Assignment Date when the sum of the pro-rata shares of Capacity assigned to the Supplier pursuant to Section 11.4.1 exceeds 150 MMBtus. The Supplier shall accept additional increments of Capacity on the following Assignment Dates commensurate with any cumulative increase in the sum of pro-rata shares of Capacity assigned to the Supplier, as rounded to the nearest 200 MMBtus. Each increment of Capacity accepted by the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative increase of the pro-rata shares of assigned Capacity as established in accordance with Section 11.4.1. Section 11.4.2 shall not apply to a Customer that is acting as its own Supplier.

11.4.6 If a Customer is acting as its own Supplier, the Company shall assign Capacity to the Customer in an amount equal to the Customer's TCQ, as established pursuant to Section 11.3.

11.5 Release of Contracts

11.5.1 With the exception of Company-Managed Supplies and Peaking Capacity, Capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or lesser rate paid by the Company and including all surcharges, through pre-arranged Capacity releases, pursuant to applicable laws and regulations and the terms of the governing tariffs.

11.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released for a term beginning on the first Gas Day of the Month following the Assignment Date through the expiration date of the respective capacity contract being assigned. and ending on October 31. For example, contracts assigned to a Supplier on April 25 of a given year shall be released for a term beginning on May 1 of that year and ending on October 31 of that year.

11.5.3 The Company reserves the right to adjust releases of Storage Withdrawal Capacity in the event that fifty percent (50%) or more of the total Storage Withdrawal Capacity serving a Gas Service Area has been assigned to Suppliers. Such adjustments may include, but are not limited to, the reassignment of certain Storage Withdrawal Capacity as Company-Managed Supplies in order for the Company to maintain operational control over Capacity resources associated with system balancing, and/or the retention of specific Capacity resources associated with system balancing and the implementation of a balancing charge to offset the associated costs.

11.6 Annual Reassignment of Capacity

11.6.1 On each Annual Reassignment Date, the Company shall adjust the Capacity assignments previously made to a Supplier to conform with the Company's resource and requirements plans. Such previously assigned Capacity shall be replaced by the assignment to the Supplier of the pro-rata shares of the same or similarly situated Capacity on behalf of the Customers enrolled in the Supplier's Aggregation Pools (as of the first Gas Day of the Month following the Annual Reassignment Date).

11.6.2 If the reassignment of Storage Withdrawal Capacity requires adjustments to the Seasonal Storage Capacity previously assigned to a Supplier, the Company shall reassign Seasonal Storage Capacity to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to inventories in place pursuant to Section 11.8 of this tariff.

11.6.3 If the reassignment of Peaking Capacity requires adjustments to the MDPQ for the Supplier's Aggregation Pool, the Company shall reassign Peaking Supply to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to supplies pursuant to Section 14 of this tariff.

11.7 Recall of Capacity

11.7.1 If the pro-rata shares of Capacity assignable to a Supplier decline because one or more of the Supplier's Customers has returned to Sales Service, the Company shall have the right, but not the obligation, to recall from the Supplier the pro-rata shares of Capacity previously assigned to the Supplier on behalf of such Customers. The decision on whether to exercise its Capacity-recall rights shall be made by the Company in its sole reasonable discretion. If the Company elects to recall Capacity from a Supplier pursuant to this Section, such recall shall be made on the Assignment Date following the effective date of the Customer's return to Sales Service. Notwithstanding the foregoing, in the following circumstances the Company shall be required to recall Capacity associated with Customers returning to Sales Service:

(a) The Supplier returning the Customers to Sales Service certifies that it is ceasing all business operations in New Hampshire;

(b) The Supplier returning the Customers to Sales Service certifies that it will no longer offer service to a particular market sector (e.g., small commercial and industrial Customers) and, therefore, once such Customers are returned to Sales Service, the Supplier is not eligible to re-enroll Customers of that type; or

(c) The Supplier demonstrates that it has provided Supplier Service to the Customer for a 12-month period, and for a period of no less than any 12-month increment, prior to the Customer's return to Sales Service.

11.7.2 If the Company elects to recall Storage Withdrawal Capacity from the Supplier pursuant to this Section, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company elects to reduce the MDPQ in the Supplier Service Agreement, the Company shall reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.3 In the event that a Customer in a Supplier's Aggregation Pool switches to another Supplier, the Company shall recall from the former Supplier said Customer's pro-rata shares of Capacity for reassignment to the new Supplier pursuant to Section 11.4. There shall be no change in the Customer's TCQ used to determine the Customer's pro-rata shares of Capacity for reassignment to the new Supplier. The recall of such Capacity from the Customer's former Supplier and the assignment of Capacity to the new Supplier shall be made on the Assignment Date following the effective date of the Customer's switch in Suppliers.

If the Company recalls Storage Withdrawal Capacity from the Customer's former Supplier, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company reduces the MDPQ in the Customer's former Supplier's Service Agreement, the Company shall also reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.4 The recall of Capacity by the Company shall entail the recall of released contracts pursuant to governing tariffs and/or the reduction in assigned quantities set forth in the Supplier Service Agreement. The recall of Capacity shall be executed in decrements of 200 MMBtus, commensurate with the cumulative reduction in the pro-rata shares of Capacity assigned to the Supplier, rounded to the nearest 200 MMBtus. Each decrement of Capacity assigned to the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative decrease in the pro-rata shares of Capacity recalled from the Supplier.

In the event that a Supplier is declared ineligible to nominate Gas for thirty (30) Gas Days pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such 30 Gas Days, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro-rata shares of Capacity for reassignment.

11.7.5 In the event that a Supplier is disqualified from service for a one (1) full year pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro rata shares of Capacity reassignments.

11.7.6 In the event that the Supplier fails to meet the applicable registration and licensing requirements established by law or regulation, fails to satisfy the requirements and practices as set forth in Section 20.3 of this tariff, fails to be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, fails to make timely payment under the assigned contracts, or fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement, the Company shall have the right to recall permanently any or all Capacity assigned to said Supplier. This section shall also apply to a Customer acting as its own Supplier.

11.7.7 The Supplier shall forfeit its rights to Capacity recalled by the Company pursuant to this Section. Such forfeiture shall be effected in accordance with applicable laws and regulations and the governing tariffs. In the event of Capacity forfeiture pursuant to this Section, the Supplier shall be responsible to compensate the Company for any payments due under the contracts prior to forfeiture, as well as any interest due thereon. The Company will not exercise discretion in the application of the forfeiture provisions of this Section. This section shall also apply to a Customer acting as its own Supplier.

11.8 Seasonal Storage Capacity

11.8.1 On each Assignment Date, the Company shall release Seasonal Storage Capacity to a Supplier that accepts the assignment of Storage Withdrawal Capacity pursuant to Section 11.4. The Company shall assign such Seasonal Storage Capacity consistent with the tariffs governing the release of the associated Storage Withdrawal Capacity.

11.8.2 If the Company assigns Seasonal Storage Capacity to a Supplier pursuant to Section 11.8.1 above, the Company shall transfer in-place Gas inventories to the Supplier. The quantity of inventories to be transferred from the Company to the Supplier shall be determined by multiplying the incremental Seasonal Storage Capacity assigned to the Supplier on the Assignment Date times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be charged the Company's weighted average cost of inventories in off-system storage facilities for each Dekatherm transferred from the Company to the Supplier. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two Business Days prior to each Assignment Date.

11.8.3 In the event that the Company recalls Storage Withdrawal Capacity from the Supplier pursuant to Section 11.7, the Company shall also recall Seasonal Storage Capacity from the Supplier. The Company shall determine the total Seasonal Storage Capacity to be recalled from the Supplier in accordance with the tariffs governing the Storage Withdrawal Capacity returned to the Company.

11.8.4 If the Company recalls Seasonal Storage Capacity from a Supplier pursuant to Section 11.8.3, the Supplier shall transfer in-place Gas inventories to the Company. The quantity of inventories to be transferred from the Supplier to the Company shall be determined by multiplying the decremental Seasonal Storage Capacity times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be reimbursed at the Company's weighted average cost of inventories in off-system storage facilities as of the Assignment Date, for each Dekatherm transferred from the Supplier to the Company. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two (2) Business Days prior to each Assignment Date.

11.8.5 Seasonal storage inventory percentages shall represent the amount of Seasonal Storage Capacity in each assigned storage resource that is assumed to be filled with inventories as of the first Gas Day of the month following the Assignment Date. Each September, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the storage inventory percentages for each resource that shall be applied to incremental or decremental Seasonal Storage Capacity assignments executed on each of the twelve (12) Assignment Dates beginning in October.

11.9 Company-Managed Supplies

11.9.1 The Company shall provide access to and ascribe cost responsibility for the pro-rata shares of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)], and other contracts that are not assignable to third-parties.

11.9.2 The Supplier's Service Agreement shall set forth the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 11.4 and 11.8.

11.9.3 The Company shall notify the Supplier of the conditions and/or restrictions on the use of Company-Managed Supplies pursuant to the tariffs governing the resources.

11.9.4 The Company shall invoice the Supplier for its pro-rata shares of the demand charges for Capacity contracts assigned to the Supplier as Company-Managed Supplies. The Company shall also flow through to the Supplier all costs, including Supply costs, incurred from the utilization of Company-Managed Supplies on behalf of the Supplier.

11.9.5 The Company shall nominate quantities to the Transporting Pipeline and/or other interstate pipelines and off-system storage operators on behalf of Suppliers to which the Company has assigned Company-Managed Supplies, provided that the requested Nomination conforms to the tariffs governing the resource. The Supplier shall communicate its desired Nomination quantities to the Company subject to the provisions in Sections 9.3 and 10.3 of this tariff.

11.10 Capacity Mitigation Service

11.10.1 Capacity Mitigation Service is available to Suppliers that have been assigned Capacity pursuant to Section 11 of this tariff. Such Suppliers shall have the option to take Capacity Mitigation Service from the Company for contracts that would otherwise be released to the Supplier in accordance with this tariff.

11.10.2 Within five (5) Business Days prior to the Annual Reassignment Date, the Supplier must designate those contracts that would otherwise be released to the Supplier pursuant to Section 11.5, as contracts to be managed by the Company for cost mitigation in accordance with the Company's Capacity Mitigation Service. Such designation will be effective for the period November 1 through October 31. Such notice shall be communicated in accordance with the Supplier's Service Agreement.

11.10.3 The Supplier shall pay to the Company the maximum-tariff rate or lesser rate paid by the Company, including all surcharges, for the Capacity contracts that are retained and managed by the Company. The Company shall bill the Supplier monthly for such charges.

11.10.4 The Company will market Capacity contracts designated by Suppliers for mitigation through the Capacity Mitigation Service. The Supplier shall receive a credit on its bill for Capacity Mitigation Service equal to the pro-rata share of the proceeds earned from the Company in exchange for such contract management. Such credit shall be determined on a contract-specific basis at the end of each Month and will be included in the bill sent to the Supplier in the following Month.

12 BILLING AND SECURITY DEPOSITS

12.1 The Customer shall be responsible for all charges for service furnished by the Company under the Company's applicable rates, as filed from time to time with the NHPUC, from the time service is commenced until it is terminated. The Company shall provide a single bill, reflecting unbundled charges, to Customers for Sales Service.

12.2 The Company shall offer two billing service options to Customers taking only Delivery Service: standard complete billing service and standard pass-through billing service. The Supplier shall inform the Company of the selected billing option in accordance with the provisions set forth in Section 20.5

12.2.1 Standard Complete Billing Service

The Customer shall receive a single bill from the Company for both Delivery Service and Supplier Service. The Company shall use the rates supplied by the Supplier to calculate the Supplier's portion of the single bill and integrate this billing within a single mailing to the Customer. The Company may charge a fee to the Supplier for providing this billing service as approved by the NHPUC.

The Supplier shall adhere to the Customer classes and rate structure as specified in the Company's then current Rate Schedule on file with and approved by the NHPUC. The Company shall reasonably accommodate, at the Supplier's expense, different Customer classes or rate structures as agreed to by the Company and the Supplier in the Supplier Service Agreement.

The Company shall provide an electronic file to the Supplier that will, in addition to the usage being billed, contain the calculated Supplier billing amounts for the current billing cycle. Customer revenue due the Supplier shall be transferred to the Supplier in accordance with the Supplier Service Agreement. Upon receipt of Customer payments, the Company shall provide a file for the Supplier summarizing all revenue from Supplier sales which have been received and recorded that day.

If a Customer pays the Company less than the full amount billed, the Company shall apply the payment first to Delivery Service, and if any payment remains, it shall be applied to Supplier Service.

12.2.2 Standard Pass-through Billing Service

The Customer taking Delivery Service shall receive two (2) bills: the Company shall issue one bill for Delivery Service and the Supplier shall issue a second bill for Supplier Service.

The Supplier shall be responsible for the collection of amounts due to the Supplier from the Customer. Customer payment responsibility with Suppliers shall be governed by the particular Customer/Supplier contract.

Within three (3) Business Days following the end of the Customer's billing cycle, the Company shall provide an electronic file for the Supplier that will contain the Customer's usage being billed including the current and previous meter readings.

12.2.3 The Company shall inform a Customer when Supplier Service has been initiated by a Supplier along with information on how the Customer may file a complaint regarding an unauthorized initiation of Service. This information shall be included on the first bill rendered to the Customer after such initiation.

12.2.4 A Customer acting as its own Supplier will be subject to the billing and payment requirements in Section 20.8 of this tariff.

12.2.5 Readings taken by an automated meter reading device will be considered actual readings for billing purposes.

13 SALES SERVICE

13.1 Sales Service is the Commodity service provided by the Company for Customers not electing to subscribe to Supplier Service and shall be provided by the Company, or its designated Supplier, in accordance with this tariff. Each Customer receiving Sales Service shall receive one bill from the Company reflecting delivery and Commodity charges.

13.2 A Customer receiving Sales Service on March 14, 2000 shall continue to receive Sales Service unless the Customer elects to take Supplier Service and until such time that Supplier Service is initiated for the Customer in accordance with Section 20.5 of this tariff. If the Customer terminates Supplier Service, if a Supplier terminates service to the Customer, or if the Customer's designated Supplier becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide Sales Service to the Customer. Pursuant to Section 20.5 of this tariff, the Company will initiate Sales Service for the Customer and will provide Sales Service to the Customer until such time that Supplier Service is initiated for the Customer by a new Supplier.

13.3 Any Customer whose Supplier has been assigned Capacity on behalf of said Customer pursuant to Section 11 of this tariff may elect to return to Sales Service if the Customer is no longer receiving Supplier Service. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until such time that Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to said Customer up to a maximum daily level of Gas Usage not to exceed the Total Capacity Quantity ("TCQ") of recallable Capacity assigned to the Customer's former Supplier.

13.4 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff terminates Supplier Service to the Customer, the Customer may select another Supplier. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to the Customer up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's former Supplier.

13.5 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide the Customer with Sales Service up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's Supplier.

13.6 The Company shall be under no obligation to provide Sales Service to a Customer at a maximum daily level in excess of the TCQ of recallable Capacity assigned to a Supplier on behalf of the Customer. The Company may elect to provide Sales Service to the Customer if, and to the extent that, adequate system Capacity and Supplies are available and upon the same terms and subject to the same conditions as any new Customer seeking to take Sales Service.

14 PEAKING SERVICE

14.1 Applicability

Section 14 of this tariff applies to all Suppliers, and to all Customers acting as their own Supplier, that have been assigned, or have elected to be assigned, Capacity on behalf of themselves or Customers in their Aggregation Pools pursuant to Section 11 of this tariff.

14.2 Character of Service

14.2.1 Peaking Service shall be provided by the Company subject to an executed Supplier Service Agreement that sets forth the Maximum Daily Peaking Quantity ("MDPQ") and the assigned Peaking Supply for each of the Supplier's Aggregation Pools.

14.2.2 The Company shall provide quantities of Gas, at the Supplier's request, from the Supplier's Peaking Service Account as established in accordance with Section 14.4. Such quantities shall be deemed delivered by the Company and received by the Company at the Designated Receipt Point(s) for the Aggregation Pool. Peaking Service shall be firm and available to the Supplier each Gas Day in accordance with the balance of the Supplier's Peaking Service Account and the parameters of the Company's Peaking Service Rule Curve.

14.3 Rates and Charges

14.3.1 The applicable rates for Peaking Service shall be established in the Company's tariff. The Supplier shall pay a peaking demand charge based on its MDPQ of assigned Peaking Capacity as billed by the Company for the Peak Season. Such unit demand charge shall be equal to the total Capacity costs and other fixed costs associated with the Company's peaking resources, excluding costs collected through Delivery rates, divided by the estimated peaking resources needed to meet the Company's total system Peak Day requirement.

14.3.2 The Supplier shall pay a Commodity charge equal to the estimated weighted average cost of peaking supplies, including fuel retention and carrying charges. The Company shall communicate electronically, by facsimile or by other agreeable alternative means the Company's estimated weighted average cost of peaking supplies by the 15th of the month preceding the next Assignment Date. The Commodity charge will be multiplied by the volumes of Peaking Service Gas nominated by the Supplier during each Month.

14.4 Peaking Supply

14.4.1 The Customer's portion of the Peaking Supply that shall be assigned to the Supplier on behalf of the Customer shall be equal to the Peaking Supply multiplied by the ratio of the Customer's MDPQ to the aggregate MDPQ of the total system.

14.4.2 On each Assignment Date, the Company shall assign Peaking Supply to a Supplier whose MDPQ has been increased pursuant to Section 11.4. If the Company assigns incremental Peaking Supply to a Supplier, the Company shall credit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the

Peaking Service Rule Curve. The amount credited to the Supplier's Peaking Service Account shall be determined by multiplying the incremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.3 On each Assignment Date, the Company shall recall Peaking Supply from a Supplier whose MDPQ has been decreased pursuant to Section 11.7. The Company shall determine the Supplier's total Peaking Supply for recall to be equal to the difference between the cumulative total Peaking Supply assigned to the Supplier as of the previous Assignment Date and the total Peaking Supply that is assignable to the Supplier in accordance with Section 14.4.1 above.

14.4.4 If the Company recalls Peaking Supply from a Supplier pursuant to Section 14.4.3, the Company shall debit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount debited from the Supplier's Peaking Service Account shall be determined by multiplying the decremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.5 The peaking inventory percentage shall represent the level of Peaking Supply assumed to be available to a Supplier in its Peaking Service Account as of the first Gas Day of the Month following the Assignment Date for incremental and decremental assignments of Peaking Supply. Each September, the Company shall communicate electronically, by facsimile or by other agreeable alternative means the Peaking Inventory Percentages that shall be applied to incremental or decremental Peaking Supply assignments executed on each of the twelve (12) Assignment Dates beginning in October.

14.4.6 On each Annual Reassignment Date, the Company shall reset the balance in the Supplier's Peaking Service Account to equal the total Peaking Supply assignable to the Supplier on behalf of Customers enrolled in its Aggregation Pool (as of the first Gas Day of the Month following the Annual Reassignment Date) as determined in accordance with Section 14.4.1 above.

14.5 Nomination of Peaking Service

14.5.1 The Supplier shall nominate with the Company the quantity of Peaking Supply, not in excess of the amount determined pursuant to Section 14.4.2, that the Supplier desires to be provided from its Peaking Service Account for the applicable Gas Day. For an Aggregation Pool of Customers taking daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 9.3 of this tariff. For an Aggregation Pool of Customers taking non-daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 10.3 of this tariff.

14.5.2 In response to a valid Nomination for Peaking Service, the Company shall provide the requested quantity of Gas, which shall be deemed to be delivered by the Company and received by the Company at the Designated Receipt Point(s) of the Supplier's Aggregation Pool, subject to the limitations herein. Nominated quantities shall be included in the determination of receipts at the Designated Receipt Point(s) for the Supplier's Aggregation Pool which factors into the daily balancing provisions set forth in this tariff.

14.5.3 The Company may reject a Supplier's Nomination for Peaking Service if the nominated quantity would cause the balance of the Supplier's Peaking Service Account to fall to a level that is 10% or more below the minimum allowable account balance for the Month in which the Nomination is requested, as computed in accordance with the Peaking Service Rule Curve. Under such circumstances, the Company shall require the Supplier to nominate the pipeline and/or storage resources, within the contract entitlements assigned to the Supplier under Section 11, required to maintain the Supplier's Peaking Service Account above the minimum allowable account balance described above. The balance of the Supplier's Peaking Service Account may not in any event fall below zero (0).

14.5.4 The Company shall provide Peaking Service supplies to the Supplier only when the volumes in the Peaking Service Account for the Aggregation Pool are greater than zero (0).

14.6 Peaking Service Critical Day Provisions

14.6.1 In the event that the volumes in a Supplier's Peaking Service Account for an Aggregation Pool are reduced to a level below the minimum allowable account balance as computed in accordance with the Company's Peaking Service Rule Curve, the Company may issue an OFO to such Supplier pursuant to Section 16 of this tariff.

14.6.2 In the event that the total volumes of all Peaking Service Accounts within one or more of the Company's Gas Service Areas are reduced to levels below the total minimum allowable account balances as computed in accordance with the Company's Peaking Service Rule Curve, the Company may declare a Critical Day and issue a blanket OFO pursuant to Section 16 of this tariff.

14.6.3 If, on a Critical Day, the Company projects, based on the Supplier's Nominations, that the Supplier's scheduled deliveries to the Designated Receipt Point(s) of an Aggregation Pool are less than the maximum feasible volumes for deliveries on the Transporting Pipeline, the Company may issue an OFO to the Supplier in accordance with Section 16 of this tariff.

15 DISCONTINUANCE OF SERVICE

15.1 The Company shall notify a Customer's Supplier of record that it has initiated any applicable billing and termination procedures as prescribed by the NHPUC. In the event that the Company discontinues Delivery Service to a Customer in accordance with the provisions set forth above, the Company shall provide electronic notification to the Customer's Supplier of record upon final billing to the Customer. The Company shall not be liable for any revenue loss to the Supplier as a result of any such disconnection.

16 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS

16.1 In the event of a material and significant threat to the operational integrity of the Company's system, the Company may declare a Critical Day.

16.2 Circumstances constituting a threat to the operational integrity of the system that may cause the Company to declare a Critical Day shall include, but not be limited to: (1) a failure of the Company's distribution, storage, or production facilities; (2) near-maximum utilization of the Company's distribution, storage, production, and Supply resources; (3) inability to fulfill firm service obligations; and (4) issuance of an OFO or similar notice by upstream transporters.

16.3 In the event that the Company has declared a Critical Day, the Company will have the right to issue an Operational Flow Order ("OFO") in which the Company may instruct Suppliers to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system, within the contract entitlements, if any, assigned to the Supplier under Section 11 hereof. An OFO may be issued on a pipeline or point-specific basis. An OFO may be issued by the Company as a blanket order to all Suppliers or to an individual Supplier whose actions are determined by the Company to jeopardize system integrity. The Company may issue an OFO to an individual Supplier if the Company faces Gas cost exposure in excess of daily cashout or imbalance penalties as set forth in Sections 9.6, 9.7, 10.6, and 10.7 for any under-deliveries or over-deliveries caused by that Supplier.

16.4 The Company will provide the Supplier with as much notice as is reasonably practicable of the issuance and removal of a Critical Day or an OFO; under most circumstances, the Company intends to provide at least twenty-two (22) hours' notice prior to the start of the Gas Day for the issuance of the Critical Day or OFO. Notification of the issuance and removal of a Critical Day or an OFO will be made by means as established in the Supplier Service Agreement. The Supplier will be responsible for coordinating with its Customers any change to the Customer's quantity of Gas Usage. An OFO or Critical Day will remain in effect until its removal by the Company.

16.5 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an OFO will be subject to the Critical Day provisions of Sections 9.6 and 10.6 of this tariff.

17 FORCE MAJEURE AND LIMITATION OF LIABILITY

17.1 Neither the Company nor the Supplier will be liable to the other for any act, omission, or circumstance occasioned by or in consequence of any event constituting force majeure, and unless it is otherwise expressly provided herein, the obligations of the Company and the Supplier then existing hereunder will be excused during the period thereof to the extent affected by such event of force majeure, provided that reasonable diligence is exercised to overcome such event. As used herein, force majeure will mean the inability of the Company or the Supplier to fulfill its contractual or regulatory obligations: as a result of compliance by either party with an order, regulation, law, code, or operating standard imposed by a governmental authority; by reason of any act of God or public enemy; by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, or breakage or accident to machinery or pipeline (which breakage or accident is not the result of the negligence or misconduct of the party claiming force majeure); by reason of any declaration of force majeure by upstream Transporting Pipelines; or by reason of any other cause, whether the kind enumerated herein or otherwise, not within the control of the party claiming force majeure and which by the exercise of reasonable diligence such party is unable to prevent or overcome. Notwithstanding the foregoing, the Customer's and the Supplier's obligation to make any payments required under this tariff will in no case be excused by an event of force majeure. Nor will a failure to settle or prevent any labor dispute or other controversy with employees or with anyone purporting or seeking to represent employees be considered to be a matter within the control of the party claiming excuse. The party claiming force majeure will, on request, provide the other party with a written explanation thereof and of the remedy being undertaken.

17.2 The Company shall be liable only for direct damages resulting from the Company's conduct of business when the Company, its employees, or agents have acted in a negligent or intentionally wrongful manner. In no event shall the Company be liable to any party for any indirect, consequential, or special damages, whether arising in tort, contract, or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under this tariff or in accordance with or required by law, including, without limitation, termination of the Customer's service.

17.3 If the Company is unable to render firm Delivery Service to the Customer taking such service as contemplated by this tariff as a result of force majeure and such inability continues for a period of thirty (30) Gas Days, the Customer may provide written notice to the Company of its desire to terminate Delivery Service at the expiration of thirty (30) Gas Days from the Company's receipt of such notice, but no sooner than sixty (60) Gas Days following the outset of the force majeure. If the Company has not restored Delivery Service to the Customer at the end of such notice period, the Customer's Delivery Service will terminate and both parties will be released from further performance hereunder, except for obligations to pay sums due and owing as of the date of termination.

17.4 The Company and the Supplier shall indemnify and hold the other and their respective affiliates, and the directors, officers, employees, and agents of each of them (collectively, "affiliates") harmless from and against any and all damages, costs (including attorney's fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively, "liabilities"), resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of either party in connection with the performance of the indemnifying party's obligations under this tariff. The Company and the Supplier shall waive recourse against the other party and its affiliates for or arising from the non-negligent performance by such other party in connection with the performance of its obligations under this tariff.

18 CURTAILMENT

18.1 Whenever the integrity of the Company's system or the Supply of the Company's Customers taking Sales Service or Delivery Service is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole reasonable judgment, curtail or interrupt Gas service or reduce pressure as set out in Section 18, Supply and Capacity Shortage Allocation Policy of this tariff. Such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect. The Company will use efforts reasonable under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

18.2 The Company shall communicate notice of curtailment as soon as practicable to the Suppliers of affected Customers by means as specified in the Supplier Service Agreement.

18.3 The Company shall take reasonable care in providing regular and uninterrupted service to its firm Customers, but whenever the Company deems that the situation warrants any interruption or limitation in the service to be rendered, such interruption or limitation shall not constitute a breach of the contract and shall not render the Company liable for any damages suffered thereby by any person, or excuse the Customer from further fulfillment of the contract.

18.4 In any case where the Company determines in its judgment that a curtailment or interruption of firm services is necessary, the Company will curtail and/or interrupt firm Delivery Service and Sales Service Customers on a nondiscriminatory basis.

19 TAXES

19.1 In the event a tax of any kind is imposed or removed by any governmental authority on the distribution of Gas or on the gross revenues derived from the distribution of Gas at retail (exclusive, however, of taxes based on the Company's net income), the rate for service herein stated will be adjusted to reflect said tax. Similarly, the effective rate for service hereunder will be adjusted to reflect any refund of imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental or regulatory authorities.

19.2 The Customer will be responsible for all taxes or assessments that may now or hereafter be levied with respect to the Gas or the handling or subsequent disposition thereof after its delivery to the

Delivery Point. However, if the Company is required by law to collect and/or remit such taxes, the Customer will reimburse the Company for all amounts so paid. If the Customer claims exemption from any such taxes, the Customer will provide the Company in writing its tax exemption number and other appropriate documentation. If the Company collected any taxes or assessments from the Customer and is later informed by the Customer that the Customer is exempt from such taxes, it shall be the Customer's responsibility to obtain any refund from the appropriate governmental taxing agency.

19.3 The Supplier will be responsible for all production, severance, ad valorem, or similar taxes levied on the production or transportation of the Gas before its delivery to the Designated Receipt Point. The Supplier will also be responsible for sales taxes imposed on Gas delivered for the Customer's account. However, if the Company is required by law to remit such taxes to the collecting authority, it will do so and invoice the Supplier for such taxes paid on the Supplier's behalf.

20 SUPPLIER TERMS AND CONDITIONS

20.1 Applicability

The following terms and conditions shall apply to every Supplier providing Supplier Service in the State of New Hampshire, to every Customer doing business with said Suppliers, and to Customers acting as their own Supplier.

20.2 Obligations of Parties

20.2.1 Customer

Unless otherwise agreed to by the Company and the Customer, a Customer shall select one Supplier for each account at any given time. A Customer electing Supplier Service must provide the selected Supplier with its applicable Authorization Number. A Customer may choose only a Supplier who meets the terms described in Sections 20.2.3 and 20.3 below and who meets any applicable registration requirements established by law or regulation.

20.2.2 Company

The Company shall deliver Customer purchased Gas from the Designated Receipt Point to the Delivery Point in accordance with the service selected by the Customer pursuant to this tariff and, among other things, shall:

(a) Provide Customer service and support, including call center functions, for services provided by the Company under this tariff;

(b) Respond to service interruptions, reported Gas leaks, and to other Customer safety calls;

(c) Handle connections, curtailments, and terminations for services provided by the Company under this tariff;

(d) Read meters;

(e) Submit bills to Customers for Delivery Service and if contracted by the Supplier, for Supplier Service in accordance with Section 12.2.1.

(f) Address billing inquiries for Delivery Service;

(g) Answer general questions about Delivery Service;

(h) Provide to Suppliers, on request, the data format and procedures for electronic information transfers and funds transfers;

(i) Arrange for or provide Sales Service to the Customer at the request of the Customer in accordance with the Company's tariff; and

(j) Provide information regarding, at a minimum, rate tariffs, billing cycles, Capacity assignment methods, and Consumption Algorithms.

20.2.3 Supplier

The Supplier shall act on behalf of the Customer to acquire Supplies and to deliver them to the Designated Receipt Point pursuant to the service selected by the Customer and the requirements of this tariff.

The Supplier is responsible for enrolling Customers pursuant to Section 20.5 of this tariff.

The Supplier must request, complete and sign a Supplier Service Agreement to act as a Supplier on the Company's system, satisfy the Supplier requirements and practices as set forth in Section 20.3 of this tariff, be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign Capacity, if any, under Section 11, and be and remain eligible to provide service to Customers in New Hampshire.

The Supplier is responsible for completing all transactions with the Company and for all applicable charges associated with Customer enrollment and changes in the Customer's service as set forth in Section 20.5 and Attachment B.

20.3 Supplier Requirements and Practices

20.3.1 The Company shall have the right to establish reasonable financial and non-discriminatory credit standards for qualifying Suppliers. Accordingly, in order to serve Customers on the Company's system, the Supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three (3) years, as well as two (2) trade and two (2) banking references. To the extent that such annual reports to shareholders are not publicly available, the Supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies, and subsidiaries. The Supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The Supplier shall be subject to a credit investigation by the Company. The Company shall review the Supplier's financial position periodically.

20.3.2 The Supplier shall also confirm in the Supplier Service Agreement that:

(a) The Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) The Supplier is not aware of any change in business conditions which would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) The Supplier has no delinquent balances outstanding for services previously provided by the Company, and the Supplier has paid its account according to the established terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding which would materially affect the Supplier's ability to remain solvent as a business entity.

(e) The Supplier's New Hampshire business advertising and marketing materials conform to all applicable state and federal laws and regulations.

20.3.3 In the event the Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company shall require the Supplier to provide one of the following at the Maximum Financial Liability as calculated below:

(a) Advance deposit;

(b) Letter of credit;

(c) Surety bond; or

(d) Financial guaranty from a parent company that meets the creditworthiness criteria.

The Company shall base the Supplier's maximum financial liability as two (2) times the highest month's aggregated Gas Usage of all Customers currently served by the Supplier at the highest Monthly Index in the preceding twenty-four (24) Months. This amount may be updated continuously, and at minimum, whenever the aggregated Gas Usage of all Customers served by the Supplier changes by more than 25%. The Supplier agrees that the Company has the right to access and apply the deposit, letter of credit, or bond to any payment of any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other amounts owed to the Company, or to secure additional Gas supplies, including payment of the costs of the Gas supplies themselves, the cost of transportation storage, and other related costs incurred in bringing those Gas supplies into the Company's system. The Supplier shall continue its obligation to maintain its financial security instrument until it has satisfied all of its outstanding claims with the Company. The Supplier's financial security as established above must be in place no later than five (5) Business Days prior to the first day of each calendar month in order for the Supplier to maintain its eligibility to provide service to Customers.

20.3.4 The Supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of Supplies which it desires the Company to transport to its Customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these Gas supplies to the Designated Receipt Point.

20.3.5 The Supplier shall warrant to the Company that it has good title to or lawful possession of all Gas delivered to the Company at the Designated Receipt Point on behalf of the Supplier or the Supplier's Customers. The Supplier shall indemnify the Company and hold it harmless from all suits, actions, debts, accounts, damages, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said Gas.

20.3.6 The Supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates, or permits to enable Gas to be delivered to the Company's system.

20.3.7 By agreeing to provide service under this tariff, the Supplier acknowledges that adherence to any applicable law regarding unfair trade practices, truth in advertising law, or law of similar import is required. Any Supplier found by a court of competent jurisdiction to have willfully or repeatedly violated the New Hampshire Consumer Protection Act, N.H.R.S.A. Ch. 358-A; the Federal Trade Commission Telemarketing Sales Rules, 16 C.F.R. Part 310; or the regulations promulgated pursuant to the Federal Trade Commission Act, 15 U.S.C. § 45 (a) (1), may be suspended or disqualified from acting as a Supplier on the Company's system.

20.3.8 If the Supplier fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement (e.g., failure to deliver Gas or late payment of bills rendered or failure to execute a capacity assignment), the Company maintains the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system. Written notice of such an intent to terminate the Supplier's eligibility shall be given to the Supplier, its Customers, and the NHPUC. Notification to the Supplier shall be via Registered U.S. Mail - Return Receipt Requested or other means of documented delivery. Upon issuance of such written notice, the Company shall have the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system at the expiration of ten (10) Gas Days after the giving of such notice, unless within such ten (10) Gas Day period the Supplier shall remedy to the full satisfaction of the Company such failure. Termination of such Supplier eligibility for any such cause shall be a cumulative remedy as to the Company, and shall not release the Supplier from its obligation to make payment of any amount or amounts due or to become due from the Supplier to the Company under the Company's applicable tariffs. Customers whose Supplier's deliveries have been terminated will be placed on Sales Service pursuant Section 13 of this tariff.

20.4 Access to Usage History and Current Billing Information

The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to requesting the Company to release the Company's historic usage information specific to that Customer to such Supplier.

The Company shall be required to provide the most recent twelve (12) months of a Customer's historic usage data to a Supplier, provided that the Supplier has received the appropriate authorization as set forth above.

20.5 Enrollment, Cancellation, and Termination of Supplier Service

20.5.1 The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to initiating Supplier Service to the Customer.

20.5.2 The Supplier must provide the Company with the following minimum information in the Company's predetermined format prior to the commencement or termination of service by the Supplier pursuant to Section 20.5 of this tariff:

(a) The Customer's name and current Authorization Number;

(b) The name of the Supplier;

(c) The Customer's billing option (for commencement of service);

(d) The type of change in Supplier Service (e.g., commencement of service, termination of service, or cancellation of service due to the rescission of an agreement with the Supplier by the Customer); and

(e) Any additional information reasonably required by the Company.

The Company shall determine whether each Customer's enrollment request as provided by a Supplier is complete and accurate, and matches the Customer's account record. In the event that the enrollment request is incomplete, inaccurate, or does not match the Customer's account record, then the Company will notify the Supplier so that the Supplier can resolve any discrepancies.

20.5.3 A change in Supplier Service will normally be made on a monthly metering and billing cycle basis, with changes taking effect on the date of the Customer's next scheduled meter read. Enrollment forms must be transmitted no less than ten (10) Business Days prior to the Customer's next scheduled meter read. If more than one Supplier submits a Supplier Service transaction for a given Customer during the monthly billing cycle, the first completed transaction that is received during the cycle shall be accepted. All other transactions shall be rejected. Rejected transactions may be resubmitted after the Customer's next scheduled meter read.

20.5.4 If the Supplier submits information to the Company to terminate Supplier Service to a Customer less than ten (10) Gas Days before the next scheduled meter read, Supplier Service shall be terminated on the date of the Customer's subsequent scheduled meter read. The Company shall confirm the termination date for Supplier Service.

20.5.5 In those instances when a Customer who is receiving Supplier Service from an existing Supplier initiates such service with a new Supplier, the Company shall send the date for the Customer's change in Supplier Service to the existing Supplier. To terminate Supplier Service with a Supplier and to initiate Sales Service, a Customer shall so inform the Company and the Supplier. Supplier Service shall be terminated on the date of the Customer's next scheduled meter read provided that the Company receives notice of such termination no less than ten (10) days in advance of the next scheduled meter read. Where such notice is received by the Company in less than ten (10) days in advance of the next scheduled read, the termination shall be effective as of the date of the following scheduled read. The Company shall send the Customer's termination date for Supplier Service to the Supplier.

20.5.6 A Customer who moves within the Company's service territory shall have the opportunity to notify its existing Supplier that it seeks to continue Supplier Service with said Supplier. Upon such notification, the Supplier may enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer at the new location. The Company shall make the necessary adjustments to the Supplier's affected Aggregation Pools, including but not limited to, changes to Designated Receipt Points, and quantities of Capacity for assignment, if any, pursuant to this tariff and the Supplier's Service Agreement with the Company. In the event that the existing Supplier does not enroll the Customer for Supplier Service at the new location, the Company shall arrange for or provide Sales Service to the Customer.

20.5.7 In those instances when a new Customer moves to the Company's service territory, the Customer's Supplier must enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer. Otherwise, the Customer shall receive Sales Service in accordance with Section 13.

20.5.8 The Company may charge fees to the Supplier for processing the transactions described in this Section, as approved by the NHPUC. These fees are included in Attachment D.

20.6 Aggregation Pools

20.6.1 The aggregation of Customer accounts into an Aggregation Pool is limited by the Delivery Service of the respective Customers. Non-daily metered Customers subscribing to Delivery Service under Rate Schedules G-41, G-42, G-51 and G-52 must be aggregated in a separate pool from Customers subscribing to daily metered service under Rate Schedules G-43, G-53, and G-54.

20.6.2 Non-daily metered Customers taking Delivery Service pursuant to Section 10 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.3 Daily metered Customers taking Delivery Service pursuant to Section 9 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company’s designated Gas Service Areas.

20.6.4 A separate Supplier account will be established for each Supplier Aggregation Pool.

20.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

20.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Attachment B.

20.7 Imbalance Trading

20.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company’s provision of information on Supplier imbalances for said Month.

20.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.

20.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

20.7.4 Daily imbalance trades must be point-specific on those Gas Days when the Transporting Pipeline required the Company to balance on a point-specific basis.

20.8 Billing and Payment

20.8.1 By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the prior Month. The Company will provide Suppliers with their Customers’ consumption data based on estimated or actual meter readings at the appropriate cycle read dates for each Customer in the Aggregation Pool pursuant to Section 12 of this tariff. This data will be provided on a rolling basis as readings or estimates are made.

20.8.2 Calculation of the charges applicable to the Aggregation Pool will be based on aggregated Gas Usage and other such indicators of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, including but not limited to imbalance charges, credits or penalties, shall be billed to the Supplier on a calendar month basis.

20.8.3 The Supplier shall have ten (10) Business Days from the date of such statement to render payment to the Company. The Supplier shall render payment by means of electronic funds transfer to the Company. The late payment rate will apply to all amounts outstanding after ten (10) days.

20.8.4 If the correctness of the Company's bill to the Supplier is questioned or disputed by the Supplier, an explanation should be promptly requested from the Company. If the bill is determined to be incorrect, the Company shall issue a corrected bill. In the event that the Supplier and the Company fail to agree on the amount of the bill, the Supplier may file a complaint with the Commission to resolve such complaint.

21 CUSTOMER DESIGNATED REPRESENTATIVE

21.1 The Customer may appoint a Designated Representative to satisfy or undertake the Customer's duties and obligations; including, but not limited to submitting and/or receiving notices, making nominations, arranging for trades of imbalances, and performing operational and administrative tasks; provided, however, that under no circumstances will the appointment of a Designated Representative relieve the Customer of the responsibility to make full and timely payment to the Company for all Delivery Service provided under this tariff.

21.2 A request by a Designated Representative to the Company that contains the Customer's Authorization Number will be deemed to be confirmation that the Customer has designated such person or entity as a Designated Representative. A Customer may appoint only one (1) Designated Representative per account.

21.3 Under any agency established hereunder, the Company shall rely upon information concerning the applicable Customer's Delivery Service that is provided by the Designated Representative. All such information shall be deemed to have been provided by the Customer. Similarly, any notice or other information provided by the Company to the Designated Representative concerning the provision of Delivery Service to such Customer shall be deemed to have been provided to the Customer. The Customer shall rely upon any information concerning Delivery Service that is provided to the Designated Representative as if that information had been provided directly to the Customer.

21.4 The Customer shall agree to indemnify the Company and hold it harmless from any liability (including reasonable legal fees and expenses) that the Company incurs as a result of the Designated Representative's negligence or willful misconduct in its performance of agency functions on the Customer's behalf.

IV. ATTACHMENTS

1 ATTACHMENT A
Supplier Service Agreement

GAS SUPPLIER SERVICE AGREEMENT

This Agreement made this **[day]** day of **[month]**, 20**[xx]**, between Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, a New Hampshire Corporation with a principal place of business at 15 Buttrick Road, Londonderry, NH 03053 (the "Company") and **[name of supplier]**, a **[state]** company with a principal place of business at **[address]** ("Supplier"). The Company and the Supplier is also individually referred to herein as a "Party" or collectively as the "Parties."

BASIC UNDERSTANDINGS

Whereas, the Company operates as a natural gas local distribution company and provides firm transportation of third- party gas on its distribution system; and

Whereas, the Company's Tariff (the "Tariff") on file with, and approved by, the New Hampshire Public Utilities Commission (the "NHPUC") permits delivery service customers to assign their rights of nominating and scheduling delivery of gas for transportation on the Company's system to a third-party natural gas supplier; and

Whereas, Supplier seeks to nominate and schedule delivery of gas for distribution on the Company's system on behalf of one or more customers taking delivery service from the Company; and

Whereas, the Company's Tariff, Part III, Section 20.2.3, requires Supplier to enter into this Supplier Service Agreement (the "Agreement") with the Company prior to the initiation of Supplier Service, as defined therein; and

Now therefore, the Parties hereto, each in consideration of the agreement of the other, do hereby agree as follows:

I. SCOPE AND APPLICATION

1.0 This Agreement shall be subject to the Company's Tariff as on file with the NHPUC and in effect from time to time. The Company's Tariff and applicable Rate Schedules are hereby incorporated by reference as though directly set forth herein. In the event the terms of this Agreement conflict with the Company's Tariff, the Tariff shall control.

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1.1 This Agreement is intended for use between the Company and natural gas suppliers providing service to customers on the Company's distribution system, and may not be waived, altered, amended, or modified, except as provided herein.

1.2 Exhibits A and B, attached hereto and incorporated herein by reference, include additional terms that are a part of this Agreement.

II. DEFINITIONS

2.0 Any capitalized terms used in this Agreement and not defined herein shall be as defined in the Tariff or as stated in the NHPUC's regulations.

III. TERM

3.0 This Agreement shall become effective on the date hereof (the "Effective Date") and shall continue in full force and effect from month to month unless terminated by either Party by written notice given no less than thirty (30) days prior to the desired termination date, or unless otherwise agreed by the Parties. Notwithstanding the foregoing, the Parties agree to abide by all terms of this Agreement until any transactions that are outstanding at the time of termination are completed, including, but not limited to, the payment by Supplier to the Company of any and all outstanding balances.

3.1 Notwithstanding anything to the contrary elsewhere in this Agreement or in the Company's Tariff, any Party, by written notice to the other Party (the "Breaching Party") may terminate this Agreement, in whole or in part, with respect to such Breaching Party or suspend further performance without terminating this Agreement upon the occurrence of any of the following:(a) the Breaching Party terminates or suspends doing business; (b) the Breaching Party becomes subject to any bankruptcy or insolvency proceeding under federal or state law (unless removed or dismissed within sixty (60) days from the filing thereof), or becomes insolvent, becomes subject to direct control of a transferee, receiver or similar authority, or makes an assignment for the benefit of creditors; or (c) the Breaching Party commits a material breach of any of its obligations under this Agreement or the Tariff and has not cured such breach within fifteen (15) days after receipt of a written notice from the other Party specifying the nature of such.

3.2 Consistent with the provisions of Part III, Section 20.3.8 of the Company's Tariff, the Company also maintains the right to terminate the Supplier's eligibility to act as a Supplier. on the Company's system in the event that Supplier fails to comply with or perform any of the obligations on its part established in the Tariff or in this Agreement, including but not limited to, failure to deliver gas or to make payment of amounts due to the Company.

3.3 Notwithstanding the Effective Date, Supplier acknowledges and agrees that the Company is obligated to provide services pursuant to this Agreement only upon full satisfaction, or the Company's express written waiver, of the Conditions Precedent set forth in Article IV of this Agreement.

3.4 No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

3.5 The enumeration of the foregoing remedies shall not be deemed a waiver of any other remedies to which either Party is legally entitled.

IV. CONDITIONS PRECEDENT

4.0 The following requirements shall be conditions precedent to the Company's obligations hereunder:

(a) Supplier shall provide the Company with all information requested in Exhibits A and B attached hereto and incorporated herein;

(b) Pursuant to Part Ill, Section 20.3.1 of the Company's Tariff, the Company shall confirm the Supplier's creditworthiness. In the event that Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company will identify such deficiencies to the Supplier, and the Supplier shall provide financial assurances as required by the Company consistent with the provisions of Part III, Section 20.3.3;

(c) Pursuant to Part Ill, Section 20.2.3 of the Company's Tariff, Supplier shall register with the NHPUC and provide evidence of such to the Company on an annual basis;

(d) Pursuant to Part III, Section 20.2.3 of the Company's Tariff, Supplier shall demonstrate to the Company that it is an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity;

(e) Pursuant to Part Ill, Section 12.2.1 of the Company's Tariff, where Supplier elects to utilize the Standard Complete Billing Services from the Company, Supplier shall furnish to the Company a complete schedule of its relevant rates and rate pricing options for Supplier Service in written form or in an electronic format reasonably acceptable to the Company, at Company's option, no less than ten (10) Business Days prior to initial Customer enrollment for any such rate or prior to a change in Supplier's existing rates or five (5) Business Days prior to a change in rate pricing options.

(f) Prior to Customer Enrollment, Supplier shall successfully complete testing of the business-transaction communication protocols established by the Company, which may include communication by fax or telephone, electronic transactions as specified by the Company, or any other applicable communication requirements set forth by the Company.

V. SUPPLIER CERTIFICATION

5.0 In addition to the requirements listed in Section IV of this Agreement, and pursuant to Part III, Section 20.3.2 of the Company's Tariff, the Supplier hereby affirms the following:

(a) Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) Supplier is not aware of any change in business conditions that would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) Supplier has no delinquent balances outstanding for services previously provided by the Company, and Supplier has paid its account according to the established

terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding that would materially affect Supplier's ability to remain solvent as a business entity.

(e) Supplier's New Hampshire business advertising and marketing materials conform to all applicable New Hampshire state and federal laws and regulations.

5.1 Supplier shall promptly notify Company of any material change in its financial condition as it relates to Supplier's creditworthiness or solvency as a business enterprise.

5.2 In the event that the NHPUC enacts regulations whereby Supplier must register with the NHPUC, Supplier shall notify Company within twenty-four (24) hours in writing in the event that its registration as a Competitive Supplier is acted upon by the NHPUC in such a way that it materially affects Supplier's performance under this Agreement, including but not limited to suspension, revocation, modification, or non-renewal. Consistent with Part III, Section 20.3.8 of the Company's Tariff, revocation or non-renewal of Supplier's registration shall be grounds for immediate termination of this Agreement by Company.

VI. NOMINATIONS AND SCHEDULING

6.0 The Company and Supplier, pursuant to the Company's Tariff on file with the NHPUC and the terms of this Agreement, agree to exchange and act on information regarding the nomination and scheduling of gas for transportation on behalf of Supplier's customers.

6.1 Supplier acknowledges and agrees that its transportation rights under this Agreement are solely those that have been assigned to it by the Customer pursuant to the Company's Tariff. Supplier further agrees that the Company shall have no obligation to honor any nomination or scheduling request from Supplier that, in the Company's sole judgment, exceeds the scope of Supplier's assigned rights or where such nominations or requests could be reasonably refused, directly or indirectly, based on the terms of this Agreement or the Company's Tariff.

6.2 Pursuant to Part Ill, Sections 9.3.2 and 10.3.3 of the Company's Tariff, nominations will be communicated to the Company in accordance with the terms of this Agreement as set forth in Exhibit A.

6.3 In the event of a discrepancy between the volume nominated to the Company by Supplier and the volume confirmed by the Company, the discrepancy shall be allocated between and among Supplier's Aggregation Pools and/or Customers in accordance with the Pre-Determined Allocation Method set forth in Exhibit B, attached hereto. In the event that the Supplier has not provided the Company with a Pre-Determined Allocation Method, the discrepancy will be allocated consistent with the provisions of the Company's Tariff.

VII. CAPACITY ASSIGNMENTS

7.0 The Supplier's Maximum Daily Peaking Quantity ("MDPQ") may be modified during the calendar year in accordance with the provisions of Part Ill, Sections 11.0 and 14.0 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.1 Pursuant to Part III, Section 11.9.2 of the Company's Tariff, the quantity of each Company Managed Supply assigned to Supplier may be modified during the calendar year in accordance with Part III, Sections 11.4 and 11.8 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.2 In accordance with Part Ill, Sections 11.0 and 14.0 of the Company's Tariff, the quantity of Capacity assigned to Supplier may be modified during the calendar year. In addition, the Company shall have the right to adjust a Customer's total capacity quantity C'TCQ") if the Company determines that the TCQ calculation is in error or is otherwise not calculated in accordance with the provisions of Part Ill, Sections 11.3.2.

7.3 Pursuant to Part Ill, Section 11.10.2 of the Company's Tariff, Supplier shall provide notice to the Company of its designation of contracts to be managed by the Company for cost mitigation purposes by the means set forth in Exhibit 8.0.

VIII. LEFT BLANK INTENTIONALLY (RESERVED FOR FUTURE USE)

IX. BILLING AND PAYMENT

9.0 Bills, fees and charges for services provided by the Company, including, but not limited to, monthly cashouts, monthly imbalance charges, daily imbalance charges, and any other applicable charges set forth in the Tariff or in this Agreement, shall be

rendered to Supplier on a monthly basis and shall be due upon receipt of said bill, unless otherwise specified in Exhibit A.

In addition to any other right or remedy available to the Company, Supplier's failure to make payment within ten (10) days of the posting date on the bill shall result in the addition of interest on any unpaid balance calculated at the maximum monthly rate allowable by the Company's Tariff. Interest shall accrue commencing from the date said bill was posted. The posting date is the date the bill is transmitted to Supplier. The bill may also be transmitted electronically if agreed to between the Parties in Exhibit A.

9.1 The Company shall have the right to deduct any amounts owed by Supplier to the Company for such services, which are thirty (30) days or more past due, from any amounts collected in the normal course of business by the Company on the Supplier's behalf. Amounts subject to a good faith dispute will not be subject to deduction.

9.2 The Parties agree to cooperate and provide each other with necessary documentation relating to any transactions resulting hereunder, including but not limited to, applicable sales or other tax exemptions. The Parties agree that Supplier's failure to comply with the provisions of this Article IX shall constitute default of payment under the Tariff and expose Supplier to liability thereunder as well as under this Agreement.

9.3 Consistent with the provisions of Part III, Sections 20.3.1 and 20.3.3 of the Company's Tariff, Supplier shall satisfy the creditworthiness standards established by the Company. In the event the Supplier has not demonstrated satisfaction of the Company's creditworthiness standards, the Supplier shall provide, upon ten (10) days written notice from the Company, financial assurance in the form of an advance deposit, letter of credit, surety bond or financial guaranty from a parent company, as reasonably determined by the Company. The amount of any such financial assurance required by the Company shall be calculated in accordance with the provisions of Part III, Section 20.3.3 of the Company's Tariff. The Company shall review Supplier's satisfaction of the Company's creditworthiness standards every twelve (12) months during the term of this Agreement giving consideration to Supplier's payment history in the preceding twelve-month period. Upon the request of Supplier, the Company shall exercise its sole reasonable discretion to determine whether a change in the form of financial assurance is warranted. In the event that the Company requires financial assurances in the form of a deposit, such deposits shall accrue interest in accordance with the Company's Tariff. Such deposit shall be returned to Supplier within thirty (30) days of the expiration or termination of this Agreement, provided that Supplier is not in default under this Agreement. The Company may deduct from the deposit any amount payable to the Company by Supplier under this Agreement, which has not been paid by the Supplier when due, unless such non-payment relates to a documented billing dispute between Supplier and the Company. Such deduction may be taken by the Company without notice or demand of any kind and the Company may, in its sole discretion, apply such deposit against any amount then due and payable. In the event that Company applies all or any portion of such deposit, Supplier shall deposit such sums as are necessary to replenish the security deposit to its maximum amount, within ten (10) days' notice of such deduction and application.

X. REPRESENTATIONS

10.0 Each Party represents that it is and shall remain in compliance with all applicable laws, tariffs, and NHPUC regulations during the term of this Agreement.

10.1 Each person executing this Agreement for the respective Parties represents and warrants that he or she has authority to bind that Party.

10.2 Each Party represents that (a) it has the full power and authority to execute, deliver, and perform this Agreement; (b) the execution, delivery, and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party; and (c) this Agreement constitutes that Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

10.3 Each Party shall exercise all reasonable care, diligence and good faith in the performance of its duties pursuant to this Agreement, and carry out its duties in accordance with applicable recognized professional standards.

XI. NONDISCLOSURE

11.0 Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third Party, including affiliates of such Party, without the express prior written consent of the other Party. As used herein, the term "Confidential Information" shall include, but not be limited to, all business, financial, and commercial information pertaining to the Parties, Customers of either or both Parties, Suppliers for either Party, personnel of either Party; any trade secrets; and other information of a similar nature; whether written or in intangible form that is marked proprietary or confidential with the appropriate owner's name.

11.1 Confidential Information shall not include information known to either Party prior to obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a Party who was under an obligation of confidentiality to the other Party to this Agreement, or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own Confidential Information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information. Each receiving Party shall, upon termination of this Agreement or at any time upon the request of the disclosing Party, promptly return or destroy all Confidential Information of the disclosing Party then in its possession.

11.2 Notwithstanding the preceding, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential Information pursuant to any applicable law, regulation, ruling, or order, provided that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority; and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so that it may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of any injunction to prohibit such disclosure.

11.3 No provision of this Agreement shall prohibit the Company from communicating to its Customers and prospective customers, information regarding Supplier's eligibility to conduct business on the Company's distribution system. In addition, obligations under this Article XI shall survive the termination or expiration of this Agreement.

XII. LIABILITY AND INDEMNIFICATION

12.0 The Parties acknowledge and agree that the Force Majeure provisions set forth in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.1 The Parties acknowledge and agree that the liability and indemnification provisions in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.2 For purposes of such liability and indemnification, however, the Parties acknowledge and agree that nothing in such Tariff prohibits one Party from impleading the other Party as a third-party defendant, whether or not one or both Parties are named as defendants in the initial claim of a third party. The third-party claim shall be stayed pending resolution of any dispute regarding liability and indemnification under this Agreement. Such resolution shall be final and binding upon the Parties only after agreement between the Parties or after entry of a final judgment, after any further appeals of a court of competent jurisdiction to which any appeal may have been taken from the determination of the arbitrator(s).

12.3 The Parties acknowledge and agree that for purposes of Part III, Section 17 the Company's Tariff, a Party seeking recovery from the other Party in connection with the performance of its obligations of the Tariff shall not be entitled to recovery where its own negligent acts or omissions contribute to or cause such damages, costs, fines, penalties or liabilities.

12.4 The Parties expressly acknowledge and agree that the dispute resolution provision in Article XIII of this Agreement shall apply to any and all disputes arising under this Article, including, without limitation, those disputes that arise as a result of either of

the Parties being named as a defendant in the primary action or being named as a third-party defendant by a defendant in the primary action.

12.5 Notwithstanding anything in this Agreement or the Tariff to the contrary, in no event shall any Party hereto be liable to any other Party hereto for indirect, consequential, punitive, special, or exemplary damages under any theory of law that is now or may in the future be in effect, including without limitation: contract, tort, N.H.R.S.A. Ch. 358-A, strict liability, or negligence.

12.6 Notwithstanding the availability of other remedies at law or in equity, either Party hereto shall be entitled to specific performance to remedy a breach of this Agreement by the other Party.

12.7 Supplier further agrees that it shall indemnify, defend and hold harmless the Company with respect to any claim, suit, damages or costs of any kind arising from any action or inaction of the Company in reliance upon the nominations, scheduling instructions or other communications from Supplier. The Parties agree that reliance on such instructions and communications shall be deemed reasonable and shall not constitute negligence.

12.8 The provisions of this Article XII shall survive the termination of this Agreement.

XIII. DISPUTE RESOLUTION

13.0 Disputes hereunder shall be reduced to writing and referred to the Parties' representatives for resolution. The Parties' representatives shall meet and make all reasonable efforts to resolve the dispute. Pending resolution, the Parties shall continue to fulfill their obligations under this Agreement in good faith, unless this Agreement has been suspended or terminated. If the Parties fail to resolve the dispute within thirty (30) days, they may mutually agree to pursue mediation or arbitration to resolve such issues.

13.1 The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of New Hampshire, without regard to the doctrines governing choice of law. All disputes arising hereunder shall be brought either before the NHPUC or the state courts of the State of New Hampshire.

XIV. COMMUNICATIONS

14.0 Except as otherwise provided herein, any notices given under this Agreement shall be in writing and shall be delivered to the Company as set forth in Exhibit A, by hand or sent by (a) certified mail, return receipt requested, first class postage prepaid, (b) telecopy, or (c) a nationally recognized courier service. Notices and other communications to Supplier shall also be addressed as shown on Exhibit A. Notices given hereunder shall be deemed to have been given upon receipt or any refusal to accept; telecopied notices shall be deemed to have been given upon confirmation of their receipt.

14.1 All communications required by the Company's Tariff shall be made in accordance with the schedule listed in Exhibit A. Information on active Company fax numbers and e-mail addresses shall be posted on the Company's Internet Website at http://www.libertyutilities.com/east/gas/business_partners/index.html

XV. ENFORCEABILITY

15.0 In the event that any portion or part of this Agreement is deemed invalid, against public policy, void or otherwise unenforceable by a court of law, the validity and enforceability of the remaining portions thereof shall otherwise be fully enforceable.

15.1 No waiver by any Party of any one or more defaults by the other Party in the performance of any provision of this Agreement shall operate or be construed as a waiver of any other present or future default, whether of a like or different character. No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights.

XVI. ASSIGNMENT AND DELEGATION

16.0 Any entity that shall succeed by purchase, merger or consolidation to the assets and properties, substantially or as an entity, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

16.1 Either Party may, without relieving itself of its obligations under this Agreement, assign any of its rights or obligations hereunder to an affiliated entity, but otherwise no assignment of this Agreement or any of the rights or obligations hereunder shall

be made unless there first shall have been obtained the written consent of the other Party. No assignment by Supplier shall take effect until the assignee has met the requirements of Article IV hereunder. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee.

16.2 The restrictions on assignment contained herein shall not in any way prevent either Party from pledging or mortgaging its rights as security for its indebtedness.

16.3 In addition, either Party may subcontract its duties under this Agreement to a subcontractor provided that the subcontracting Party shall remain fully responsible as a principal and not as a guarantor for performance of any subcontracted duties, and shall serve as the point of contact between its subcontractor and the other Party, and the subcontractor shall meet the requirements of any applicable laws, rules, regulations, and Tariff. The assigning or subcontracting Party shall provide the other Party with thirty (30) calendar days' prior written notice of any such subcontracting or assignment, which notice shall include such information about the subcontractor as the other Party shall reasonably require.

XVII. MISCELLANEOUS

17.0 This Agreement, all Exhibits and attachments hereto and all documents referenced herein, constitute the entire agreement between the Parties and supersedes all other agreements, communications, and representations. Paragraph headings are for convenience only and are not to be construed as part of this Agreement.

17.1 Unless otherwise provided herein, no modification of, or supplement to, the terms and provisions stated in this Agreement shall be or become effective without the written consent of both Parties.

17.2 This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed to be an original but all of which shall constitute one and the same document.

In witness whereof, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the date above.

[SUPPLIER NAME]

By ______________________ Title______________________

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

By ______________________ Title______________________

2 ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.23 per MMBtu of Daily Imbalance Volumes	
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
		Capacity for Mitigation.	
III.	Peaking Demand Charge	$ 11.39	MMBTU of Peak MDQ
IV.	Company Allowance Calculation (per Schedule 25)		
		152,544,340	Total Sendout - Therms Aug-2015 - Jul-2016
		148,757,282	Total Throughput - Therms Aug-2015 - Jul-2016
		3,787,058	Variance (Sendout - Throughput)
	Company Allowance Percentage 2016-17	2.5%	Variance / Total Sendout

3 ATTACHMENT C
Capacity Allocators

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	48.3%	19.3%	32.4%	100.0%
G-51	Low Annual /Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-42	Medium Annual / High Winter	48.3%	19.3%	32.4%	100.0%
G-52	High Annual / Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-43	High Annual / High Winter	48.3%	19.3%	32.4%	100.0%
G-53	High Annual / Load Factor < 90%	75.4%	9.2%	15.4%	100.0%
G-54	High Annual / Load Factor < 90%	75.4%	9.2%	15.4%	100.0%

NHPUC NO. 9 - GAS

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. D/B/A

LIBERTY UTILITIES

SUPERSEDING NHPUC No. 8

TARIFF

FOR

GAS SERVICE

Applicable

in

Thirty three towns in New Hampshire
served in whole or in part.

(For detailed description, see Service Area)

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day, Year, in Docket No. DG 17-048

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CHECK SHEET

The title page and pages 1-94 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

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I. GENERAL TERMS AND CONDITIONS

1 SERVICE AREA

A. Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Keene, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelham, Pembroke, Sanbornton, Tilton, Windham, ~~-~~and part of Canterbury and Winnisquam.

2 GENERAL TERMS AND CONDITIONS

A. Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission") and is open to inspection at the offices of the Company.

B. Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the ~~New Hampshire Public Utilities~~ Commission and such changes, when effective, shall have the same force as the original tariff.

C. Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

D. Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

E. No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

F. Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

G. Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

H. Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

3 CHARACTER OF SERVICE

A. Gas Supply. This Tariff applies only to the supply of gas, having a thermal content of nominally 1,000 British thermal units per cubic foot at supply pressures available in the locality in which the premises to be served are situated.

B. Determination of Therms. The gas for any billing period, expressed in hundreds of cubic feet (ccf), shall be multiplied by the average Btu of the gas send out as determined below and divided by 1,000 in order to determine the number of therms consumed in the billing period. For billing purposes, gas therms shall be determined on a "dry" basis.

The Btu therm factor of the gas sendout shall be calculated for each billing cycle from the daily weighted average Btu of the natural gas delivered to the Company by its suppliers and the gas produced at the Company's peak-shaving plants. The daily average Btu content shall be determined by appropriate gas measurement devices operated by the Company or its supplier.

C. Delivery of Gas Supply. The rates specified in this tariff are based upon the supply of service to a single customer through one delivery and metering point.

D. Use of Service at Separate Properties. The use of service at two or more separate properties will not be combined for billing purposes.

4 CUSTOMER'S INSTALLATION

A. Point of Delivery. Upon request, the Company will designate a point at which the customer shall terminate his piping for connection to the meter of the Company, but such information does not constitute an agreement or obligation on the part of the Company to furnish service.

B. Space for Meter. The customer shall provide, free of expense to the Company, a dry, warm and otherwise suitable place for the regulator or regulators, meter or meters, or other equipment of the Company which may be necessary for the fulfillment of such contracts as may be entered into with the Company.

C. Location of Meter. The space provided for the Company's meters and equipment shall be convenient access to the Company's employees and, as near as possible, to the point where the service supply pipe enters the customer's building. Its location shall be such that the meter connections are not concealed by plaster or sheathing and shall be otherwise acceptable to the Company.

D. Reverse Flow. The customer may be required to install check valves or other devices to prevent compressed air or other gases from entering the Company's mains.

5 APPLICATION FOR SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of ~~his~~ the applicant's use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Right to Reject. The Company may reject any application for service which would involve excessive cost to supply, or which might affect the supply of service to other customers, or for other good and sufficient reasons.

C. Special Contracts. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, contracts of longer terms as specified in the rate, or with a special guarantee of revenue, or both, may be required to safeguard such investment.

D. Unauthorized Use. Unauthorized connection to the Company's gas service supply facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company without notice. The use of service without notifying the Company and without enabling ~~it~~ the Company to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last meter reading of the Company's meter immediately preceding ~~his~~ the user's occupancy as shown by the Company's books.

E. Managed Expansion Program. The Managed Expansion Program ~~T~~targetseds gas expansion in specific areas that have high potential for demand. Each Managed Expansion Program project includes a Main Extension. Customers under this program avoid a portion or all of a contribution in aid of construction which would otherwise be required absent the Managed Expansion Program.

6 CREDIT

A. Prior Debts. Service will not be furnished to former customers until any indebtedness to the Company for previous service has been satisfied.

B. Deposits. Before rendering or restoring service, the Company may require a deposit subject to the ~~New Hampshire Public Utilities~~ Commission's Rules and Regulations. (See Puc 1200 rules).

7 SERVICE AND MAIN EXTENSIONS

A. Definitions. The following are definitions of terms used in these provisions relative to main and service extensions and are applicable only in ~~such~~ the main and service extensions provisions.

1. Service and Main Extensions. Extensions that require the construction of a new gas main and a service from that new main in order to provide requested gas service to a customer.

2. Service Extensions. Extensions from an Existing Gas Main to the point of delivery on the customer's premises.

3. Main Extension. An extension of the new gas main portion of a Service and Main Extension.

4. Existing Gas Main. A main that is installed in the street and through which gas is flowing.

5. Abnormal Costs. Abnormal Costs are service and/or main construction costs that are attributable to frost or ledge (including ditching or backfilling necessitated as a result of the presence of frost or ledge),and/or other conditions not typically encountered in service and/or main construction that are peculiar to the particular service and/or main construction concerned. Abnormal Costs are to be paid by the customer.

6. Extra Footage. The charge (contribution in aid of construction) for Extra Footage is $31.54 per foot. The charge will be updated annually by calculating the historical average cost per foot for Service Extensions, excluding overheads, for the most recent calendar year and the updated charge shall be effective April 1.

7. Estimated Annual Margin. The Estimated Annual Margin is equal to the estimated revenue to be derived from the monthly Customer Charge and delivery charge to be received from the customer for gas service utilizing the Service and Main Extension or Service Extension during the first twelve

(12) months after completion of the extension. The Estimated Annual Margin does not include revenue received by the Company for the cost of gas and local distribution adjustment factor.

8. Estimated Cost of Construction. For the purpose of determining the cost of Service and Main Extensions, Estimated Cost of Construction of mains and/or services includes ~~not only~~ the cost of labor and materials for such construction, ~~but also~~ and incidental or associated miscellaneous costs ~~incidental thereto or associated therewith~~, but excluding overheads. Miscellaneous costs include, but are not limited to, meter(s), traffic control and city and town road permits and degradation fees. The customer may perform on-site trenching and backfilling in accordance with the Company's specifications, in which case the Estimated Cost of Construction will be reduced to reflect the costs avoided by the Company as a result of the customer's performance of the work.

B. Costs of Extensions. In areas where the Company is authorized to operate, subject to the Application for Service provisions of this tariff, service is available as follows:

1. Residential Service Extensions. Residential Service Extensions up to 100 feet in length will be installed at no charge to customers served under either a (i) residential heating rate; or (ii) a residential non-heating rate provided that such extension is installed during the installation of a Main Extension~~,~~ or during the performance of work on cast iron/bare steel main replacements; unless there are Abnormal Costs associated with such extensions, in which case the customer shall be charged for the Abnormal Costs. For residential Service Extensions in excess of 100 feet, the customer will be charged for the Extra Footage, plus any Abnormal Costs. This Section 7(B)(1) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

2. Commercial and Industrial Service Extensions. Commercial and industrial Service Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service Extension, excluding any Abnormal Costs. If the Estimated Annual Margin is less than one-sixth of the Estimated Cost of Construction, the customer will be required to pay to the Company, in advance, any amount by which the Estimated Cost of Construction of the Service Extension exceeds six times the Estimated Annual Margin. Abnormal Costs are charged separately and are not included in the Estimated Cost of Construction for the purpose of this calculation. This Section 7(B)(2) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

3. Service and Main Extensions of Less Than $1,000,000. The Company shall not commence construction on a Service and Main Extension for which the Estimated Cost of Construction is less than $1,000,000 until the sum of (i) six times the Estimated Annual Margin for all commercial and industrial customers who have committed to take service, plus (ii) eight times the Estimated Annual Margin for all residential customers who have committed to take service equals or exceeds 25% of the Estimated Cost of Construction.

   a. Residential. Residential Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-eighth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-eighth of the Estimated Cost of Construction, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and eight times the Estimated Annual Margin, plus any Abnormal Costs.

If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated equally among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main. Abnormal Costs associated with Main Extensions will be allocated equally among all customers, unless such costs can be attributed to specific customers.

b. Commercial and Industrial. Commercial and industrial Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-sixth of the cost of construction of the Service and Main Extensions, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and six times the Estimated Annual Margin, plus any Abnormal Costs.

c. If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include in such calculations the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

d. Extensions Serving Customers in More Than One Rate Class. If the Main Extension will serve both residential and commercial or industrial customers, the Company will determine whether a contribution will be required by the customers by calculating the difference between the Estimated Cost of Construction of the Main and Service Extensions and (i) six times the Estimated Annual Margin for all commercial and industrial customers to be served, plus (ii) eight times the Estimated Annual Margin for all residential customers to be served. The Company will also include in the above calculations the Estimated Annual Margin and the Estimated Cost of Construction of Service Extensions for all existing premises for which the Company reasonably anticipates will take service. If the difference described above is positive, the customers will be required to pay to the Company such difference. The amount of payment will be allocated among all metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

4. Service and Main Extensions Greater Than or Equal to $1,000,000. If the cost of the Main Extension equals or exceeds $1,000,000, then in addition to the requirements specified in Section 7(B)(3), the Company will not commence construction unless a discounted cash flow analysis demonstrates a positive net present value over a 10-year period of the difference between the Estimated Annual Margin and the revenue requirement associated with the Estimated Cost of Construction.

C. Failure to Use Installed Gas Service. If a customer fails, within nine months after the date a service is installed under this Section 7, either in whole or in part, to make use of the service, the customer will reimburse the Company for all costs of constructing, removing and retiring the service less any contribution in aid of construction made by the customer for the service, which will be forfeited.

D. Easements, Etc. The Company is not required to construct extensions other than in public ways unless the customer provides, in advance and without expense or cost to the Company, all necessary permits, consents, authorizations and right-of-way easements, satisfactory to the Company, for the construction, maintenance and operation of the pipeline.

E. Shortest Distance. Services are run the shortest practical safe distance to the meter location. However, a customer may have the Company install a longer alternate service provided that the customer pays for the extra expense in advance of installation.

F. Winter Construction. Ordinarily, no new service pipes or main extensions are installed during the winter conditions (when frost is in the ground) unless the customer defrays the extra expenses.

G. Timing and Refunding of Contribution. Except as otherwise agreed by the Company under unusual circumstances, any required contribution in aid of construction will be made prior to installation by the Company of a service. To help cover the Company's expenses, damages and lost business, if substantial construction of the building or buildings for which gas service has been sought is not commenced by the earlier of (1) November 30th next following submission of the application; or (2) the date when the Company commences construction of the main and service concerned prior to withdrawal of the application, ten percent (10%) of the contribution will be forfeited to the Company and will not be returned to the customer. The balance of the contribution will be refunded if and when the application is withdrawn, or will be applied toward the new contribution if the customer submits a new application for service or subsequently commences construction of the building or buildings. A new application may be submitted at any time.

H. Reasonable Duration and Non-Discrimination. Under none of the foregoing provisions will the Company be required to install service pipes or to contract main extensions where the business to be secured may not be of reasonable duration or will tend, in any way, to constitute unreasonable discrimination.

I. Title. Title of all extensions constructed in accordance with the above shall be vested in the Company.

J. Other Requirements. The Company generally will not approve any application or, if it shall have given such approval, will not proceed or continue with main and/or service construction unless the Company is satisfied

1. That the final site plans, sub-division plans and plans and specification for building or buildings to be served by the main and/or service concerned, including plans for waste disposal, water and other associated systems and facilities, have been prepared and approved by owner;

2. That all permits, exceptions, approvals and authorizations of governmental bodies or agencies required for construction of such building or buildings and associated systems and facilities have been obtained;

3. That the customer is proceeding or plans promptly to proceed with such construction; and

4. That nothing has occurred or failed to occur which will or is likely to prevent or interfere with such construction.

8 INTRODUCTION OF SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of his use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Defective Installation. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

C. Unsatisfactory Installation. ~~-~~ The Company may refuse to connect if, in its judgment, the customer's equipment or use thereof might injuriously affect the equipment of the Company or the Company's service to other customers.

9 COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

A. Meters and Regulators. The Company shall furnish and install, maintain and own, any meter or meters, regulator or regulators required in the supply of service. For certain large customers, the Company shall furnish, install and maintain, at the customer’s expense, any remote meter reading equipment to record usage for daily balancing. Such equipment shall remain the property of the Company at all times.

B. Customer's Responsibility. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property, the customer shall pay the costs of repairs and replacements.

C. Relocation and/or Replacement of Company Equipment. The original service connection, including piping, meters and all other necessary or incidental equipment, which remains the property of the Company, shall be installed by the Company at its expense unless otherwise expressly provided in this tariff. Subsequent relocation and/or replacement of any such equipment on private property, whether it be for one or more service connections, shall be performed by the Company at the customer's expense unless such work is done at the request of the Company and for its convenience, in which case the Company shall bear the expense ~~thereof~~.

D. Protection by Customer. The customer shall protect the equipment of the Company on his premises and shall not permit any persons, except a Company employee having a Company photo identification card or other Company identification, to break any seals upon or do any work on any meter, service supply pipe, or other equipment of the Company located on the customer's premises.

E. Tampering. In the event the Company's meter or other property is being tampered with or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter and for any repairs or replacements required as well as for costs of inspections, investigations, and protective installation.

F. Right of Access. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, testing, repairing, removing, or exchanging any or all equipment belonging to the Company.

G. Ownership and Removal. All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service for whatever cause.

10 SERVICE CONTINUITY

A. Regularity of Supply. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service, but should the supply be interrupted by the Company for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted or fail by reason of accident, strike, legal process, state or municipal interference, or any cause whatsoever beyond its control, the Company shall not be liable for damages, direct or inconsequential, resulting from such interruption or failure.

B. Notice of Trouble. The customer shall notify the office of the Company immediately should the service be unsatisfactory for any reason or should there be any defects, leaks, trouble, or accident affecting the supply of gas.

11 CUSTOMER'S USE OF SERVICE

A. Resale Forbidden. The customer shall not, directly or indirectly, sell, sublet, assign, or otherwise dispose of to others, gas purchased from the Company, or any part thereof, without the consent of the Company. This rule does not apply to a public utility Company purchasing gas in bulk expressly for the purpose of delivering it to others.

B. Fluctuations. Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system. In the case of violation of this rule, the Company may discontinue service or require the customer to modify ~~his~~ its installation~~,~~ and/or equip it with approved controlling devices.

C. Additional Load. The service supply pipe, regulators, meters, and equipment supplied by the Company for each customer have definite capacities. The customer shall notify the Company of substantial changes in service requirements or location of appliances.

12 INSPECTIONS

A. Company's Right to Inspect. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any time later and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements. However, such inspection, ~~or~~ failure to inspect, or failure to reject shall not render the Company liable or responsible for any losses or damage resulting from defects in the installation, piping or appliances, ~~or~~ from violation of Company rules, or from accidents which may occur upon the premises of the customer.

13 MEASUREMENT

A. Supply of Meters. The measurement of gas service shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment and may, from time to time, change or alter the equipment. ~~its~~ The Company's sole obligation ~~being~~ is to supply meters that will accurately and adequately furnish records for billing purposes.

B. Special Measurements. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments on the premises of any customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the customer's load.

14 METER TESTS

A. Meter Tests. Meters are tested according to NHPUC Rules and Regulations. (See Puc 500 rules).

B. Request Tests. The fee for a special request test is $20.00 when scheduled at the mutual convenience of the Company and the customer; otherwise the amount is $30.00. (See Puc 500 rules).

C. Customer's Bill Adjustment. Should any meter fail to register correctly, the quantity of gas consumed will be determined by the Company based on information supplied by the customer and known by the Company subject to NHPUC Rules and Regulations. (See Puc 500 rules).

15 DISCONNECTION BY THE COMPANY

A. Disconnection by the Company. The Company may disconnect its service to a customer for violation of its rules subject to NHPUC Rules and Regulations. (See Puc 1200 rules).

B. Non-Payment Shut-Off. The Company may disconnect its service on reasonable notice and remove its equipment in case of non-payment of amounts billed for gas usage.

C. Shut-Off for Cause. The Company may disconnect its service on reasonable notice if entry or access to its meter or meters is refused, ~~or if access thereto is~~ obstructed, or hazardous, or for other violation of the Company's standard requirements.

D. Safety Shut-Off. The Company may disconnect without notice if the customer's installation has become dangerous or defective.

E. Defective Equipment. The Company may disconnect without notice if the customer's equipment, or use thereof, might injuriously affect the equipment of the Company or the Company's service to other customers.

F. Shut-Off for Fraud. The Company may disconnect without notice for abuse, fraud or tampering with the connections, meters or other equipment of the Company.

G. Reconnection Charge. A reconnection charge is made for reconnection of service discontinued by the Company and is payable in advance in addition to all other amounts due. The reconnection charge is made instead of the meter account charge. The amount of the reconnection charge is the same as the comparable meter account charge except when it has been necessary to dig up the service pipe or connection to effect discontinuance of service. In such cases, the reconnection charge is the price of removal and restoration of service pipe or connection.

16.1 COST OF GAS CLAUSE

A. Purpose. The purpose of this Cost of Gas Clause is to establish procedures that allow ~~Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (the "Company")~~the Company, subject to the jurisdiction of the ~~State of New Hampshire Public Utilities~~ Commission ~~("NHPUC")~~, to adjust, on a semiannual basis, its rates for firm gas sales in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchased gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit to customers receiving firm service from the Company all supplier refunds and capacity release sales.

B. Applicability. This Cost of Gas Clause ("COGC") shall be applicable to the Company and all firm gas sales made by the Company, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the NHPUC. See Section 16(N), "Other Rules."

C. Cost of Firm Gas Allowable for COGC. All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, hedging related costs, other gas supply expense incurred to procure and transport supplies and commodity related bad debt expense, the gas used in Company operations, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the COGC. Any costs recovered through application of the COGC shall be identified and explained fully in the semiannual filings outlined in Section 16(M).

D. Effective Date of Cost of Gas Factor. The seasonal Cost of Gas Factor ("COG") shall become effective upon NHPUC approval on the first day of each season as designated by the Company. Unless otherwise notified by the NHPUC, the Company shall submit COG filings as outlined in Section 16(M) of this clause on or before the first business day in September...

E. Definitions. The following terms shall be defined in this section, unless the context requires otherwise.

1. Bad Debt Expense: The uncollectible expense attributed to the portion of the Company's revenue associated with the recovery of gas costs under this clause.

2. Capacity Release Revenues: The economic benefit derived from the sale or release of transportation and storage capacity that the Company has under contract.

3. Carrying Charges: Interest expense calculated on the average monthly balance using the *monthly* prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end of month balance.

4. Correction Factor: Seasonal Adjustment necessary to align the peak day volumes used to calculate the Commercial and Industrial load factor ratios with the seasonal Commercial and Industrial High Winter and Low Winter throughput volumes applied to the cost of gas calculations.

5. Direct Gas Costs: All purchased gas costs including supplier, storage and pipeline demand and commodity costs, as well as the commodity costs for local manufactured gas (Liquid Propane Gas (“LPG”) and Liquefied Natural Gas (“LNG”)).

6. Economic Benefit: The difference between the revenues received and the marginal cost determined to serve non-core customers.

7. Inventory Finance Charges: As billed in each Winter Season for annual charges. The total shall represent an accumulation of the projected charges as calculated using the monthly average of financed inventory at the existing or anticipated financing rate through a trust or other financing vehicle.

8. Local Production and Storage Capacity Costs: The costs of providing storage service from the Company's storage facilities (*i.e.*, LNG and LPG) as determined in the Company's most recent rate proceeding.

9. Market Based Allocator (“MBA”): The method used to allocate gas costs among Commercial and Industrial Customer Classifications. These ratios are presented in Section 16(F).

10. Non-Core Commodity Costs: The commodity cost of gas assigned to non-core sales to which the COG is not applied.

11. Non-Core Sales: Sales made under non-traditional off-system sales.

12. Non-Core Sales Margins: The economic benefit derived from non-core transactions to which the COG is not applied, including non-core sales generated from the use of the Company's Gas Supply Resource portfolio.

13. Summer Commodity: The gas supplies procured by the Company to serve firm load in the Summer Season.

14. Summer Demand: The gas supply demand and transmission capacity procured by the Company to serve firm load in the Summer Season.

15. Summer Season: The calendar months May 1 through October 31.

16. Off-System Sales Margin: The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

17. Winter Commodity: The gas supplies procured by the Company to serve firm load in the Winter Season.

18. Winter Demand: Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.

19. Winter Season: The calendar months November 1 through April 30.

20. PR Allocator: The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.

21. Purchased Gas Working Capital: The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

F. Approved Cost. The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

Variable	Description	Approved Figure
MISC	Miscellaneous Overhead	$13,170
PS	Production and Storage Capacity	$1,980,428
WCA%	Working Capital Allowance Percentage	3.91%

Bad Debt % Measurement and Reconciliation Period	COG Recovery Period	Actual Bad Debt Rate	Bad Debt allowed Recovery Rate
May 2010 – April 2011	November 2011 – October 2012	Actual	Actual
May 2011 – April 2012	November 2012 – October 2013	Greater than 2.9%	Actual less 0.4
		2.5% to 2.9%	2.5%
		Less than 2.5%	Actual
May 2012 - April 2013 and each subsequent May – April period thereafter	November 2013 - October 2014 and each subsequent November – October period thereafter	Greater than 3.3%	Actual less 0.8
		2.5% to 3.3%	2.5%
		Less than 2.5%	Actual

If the Company's actual bad debt percentage is reduced to 2.5% or less during any 12 month period, which need not be the same 12 months as the measurement periods defined above, then beginning with the reconciliation filing for the period during which this bad debt percentage was achieved the Company shall thereafter recover its actual gas supply related bad debt on a fully reconcilable basis and the percentages in the table above shall no longer apply. The actual bad debt percentage shall be calculated by dividing the Company's actual net write-offs for the relevant measurement period by its revenue for the same period.

G. Cost of Gas (COG) Calculations by Customer Class. The ~~Cost of Gas (~~COG~~)~~ Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group to the total system unit capacity cost that is determined in the Company's submittal of its Capacity Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment C of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

GROUP	CUSTOMER CLASSES
Residential	Residential Heating and Non-Heating
Commercial and Industrial: Low Winter Use	G-51 through G-58
Commercial and Industrial: High Winter Use	G-41 through G-46

Winter Season Cost of Gas Formula (CGw)

The Winter Season COG shall be comprised of Winter Demand costs, Winter commodity costs, Winter reconciliation costs, Winter working capital reconciliation, Winter bad debt expenses, local production and storage capacity costs, and miscellaneous and A&G costs calculated at the beginning of the Winter Season according to the following formula:

$$CGw = Dw + Cw + Rw + WCRw + BDw + PS + ((MISC + Rbd) \times \frac{W{:}Sales)}{A{:}Sales}$$

Winter Demand Cost (Dw) Formula

Dw = DEMw – NCSMw + WCwd – R1d – R2d
and:

NCSMw = CRRw + OSSMw + SBdw
and:

WCwd = (DEMw – NCSMw) × WCA% × CC
where:

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers previously defined.

BDw = Bad Debt expense for the Winter Season.

Cw = Commodity-related direct gas cost for the Winter Season.

Dw = The total Winter Demand costs.

DEMw = Demand Charges allocated to the Winter Season defined in Section 16(E).

NCSMw = The Non-Core Sales Margins equal to the sum of the Winter Season returnable Capacity Release Revenues, and Off-System Sales Margins.

WCwd = Working Capital allowable associated with demand charges allocated to the Winter Season as defined in Section 16(K).

R1d, R2d = Supplier demand-related refunds - The Supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

CRRw = The returnable Capacity Release Revenues allocated to the Winter Season. See Section 16(E).

OSSMw = The returnable Off-System Sales Margins allocated to the Winter Season. See Section 16(E).

SBdw = Demand revenues received from Firm Stand-By Sales Service customers in the Winter Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rw = Reconciliation Costs – Winter Season deferred gas costs, Account 1920-1740 balance, inclusive of the associated Account 1920-1740 interest, as outlined in Section 16(J).

WCRw = Working Capital reconciliation adjustment associated with Winter Gas Costs - Account 1163-1422 balance as outlined in Section 16(K).

PS = The total dollar amount of costs associated with the local production and storage capacity gas less any production and storage capacity assignment revenues. ~~–~~Refer to Section 16(F) for this dollar amount.

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. ~~–~~Refer to Section 16(F) for this dollar amount.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance

W:Sales = Forecasted firm sales volumes associated with the Winter Season.

A:Sales = Forecasted annual firm sales volumes.

Winter Season Commodity (Cw) Formula

Cw = COMw + FC + WCwc – R1c – R2c
and:

COMw = WSC – NCCCw - SBcw
and:

WCwc = (COMw + FC) × WCA% × CC
where:

COMw = Commodity Charges allocated to the Winter Season as defined in Section 16(E).

FC = Inventory finance charges as defined in Section 16(E).

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

WCwc = Working Capital Allowable Associated with commodity charges allocated to the Winter Season as defined in Section 16(K).

R1c, R2c = Supplier commodity-related refunds - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds". See Section 16(I).

WSC = Commodity charges associated with gas supply sent out in Winter Season as defined in Section 16(E).

NCCCw = Non-Core Commodity Costs incurred in the Winter Season as defined in Section 16(E).

SBcw = Winter Season commodity revenues received from Firm Stand-By Gas Supply Service sales customers.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Winter Bad Debt (BDw) Formula

BDw = BD% x (Dw + Cw + Rw + WCRw)
where:

BDw = Forecasted gas supply cost related Bad Debt Expense calculated for Winter Season.

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.

Dw = Demand related costs in the Winter Season as previously defined.

Cw = Commodity related costs in the Winter Season as previously defined.

Rw = Reconciliation Costs – Winter Season deferred gas costs as previously defined.

WCRw = Winter Season Working Capital Reconciliation adjustment as previously defined.

Residential Winter Season Cost of Gas (COGwr)

All residential firm sales customers will pay the same Cost of Gas for the Winter Season. The factor represents the total forecasted Winter Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGwr = \frac{CGw}{W:Sales}$$

where:

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers previously defined.

W:Sales = Forecasted sales volumes associated with the Winter Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Summer Season Cost of Gas (COG) Formula (CGs)

The Summer Season COG shall be comprised of Summer demand costs and Summer commodity costs, Summer reconciliation costs, Summer working capital reconciliation, plus a Summer bad debt charge, and a miscellaneous and A&G charge calculated at the beginning of the Summer Season according to the following formula:

$$CGs = Ds + Cs + Rs + WCRs + BDs + \left((MISC + Rbd) \times \frac{S:Sales}{A:Sales}\right)$$

Summer Demand Cost (Ds) Formula

$Ds = DEMs + WCsd – Rld – R2d$
and:

$WCsd = DEMs \times WCA\% \times CC$
where:

A:Sales = Forecasted annual sales volumes.

BDs = Bad Debt Expense for Summer Season.

Cs = Commodity-related direct gas costs for the Summer Season.

CGs = The total cost of gas for the Summer Season for the Company's firm sales customer previously defined.

DEMs = Demand charges allocated to the Summer Season defined in Section 16(E).

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. –Refer to Section 16(F) for this dollar amount.

R1d, R2d = Supplier refunds from pipeline demand charges - The per unit supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

Rs = Summer Season Reconciliation Costs - Account 1920-1741 balance, inclusive of the associated Account 1920-1741 interest, as outlined in Section 16(J).

S:Sales = Forecasted sales volumes associated with the Summer Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance.

WCRs = Working Capital reconciliation adjustment associated with Summer gas costs – Account 1163-1424 as outlined in Section 16(K).

WCsd = Working Capital allowable costs associated with demand costs allocated to the Summer Season as defined in Section 16(K).

Summer Season Commodity Cost (Cs) Formula

Cs = COMs – NCCCs + WCsc – R1c – R2c
and:

WCsc = (COMs – NCCCs) × WCA% × CC
where:

COMs = Commodity charges associated with gas supply sent out in the Summer Season as defined in Section 16(E).

WCsc = Working Capital allowable costs associated with commodity charges allocated to the Summer Season as defined in Section 16(K).

R1c, R2c = Supplier refunds from pipeline commodity charges - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds."

NCCCs = Non-core commodity costs incurred in the Summer Season as defined in Section 16(E).

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Summer Bad Debt (BDs) Formula

BDs = BD% x (Ds + Cs + Rs + WCRs)
where:

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.

BDs = Forecasted gas supply related Bad Debt Expense calculated for Summer Season defined in Section 16(E).

Ds = Demand related costs in the Summer Season as previously defined.

Cs = Commodity related costs in the Summer Season as previously defined.

Rs = Reconciliation Costs – Summer deferred gas costs as previously defined.

WCRs = Summer Season Working Capital Reconciliation adjustment as previously defined.

Residential Summer Season Cost of Gas (COGsr)

All residential firm sales customers will pay the same cost of gas for the Summer Season. The factor represents the total forecasted Summer Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGsr = \frac{CGs}{S:Sales}$$

where:

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

S:Sales = Forecasted sales volumes associated with the Summer Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Commercial and Industrial Winter and Summer Season Cost of Gas

The Commercial and Industrial customer classes Winter Season Cost of Gas will be based on the Winter Season average cost of gas components used for the Residential Winter Season Cost of Gas. A separate Winter Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58 and a separate Winter Season Cost of Gas Factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

The Commercial and Industrial customer classes Summer Season Cost of Gas will be based on the Summer Season average cost of gas components used for the Residential Summer Season Cost of Gas. A separate Summer Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53,G-54, G-55, G-56, G-57, and G-58 and a separate Summer Season Cost of Gas factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

These Cost of Gas Factors will be computed by applying ratios to the average demand portion of the Winter and Summer Season's cost of gas unit rate times the correction factor and then adding the remaining Residential average cost of gas unit rate.

These factors are calculated according to the following formulas:

Low Winter Use (COGwl) Formula Winter Season

COGwl = RATIOl x CFw x CGwd + CGwo

Low Winter Use (COGsl) Formula Summer Season

COGsl = RATIOl x CFs x CGsd + CGso

and:

$$RATIOl = \frac{DCcl}{DDcl} \div \frac{DCc}{DDc}$$

and:

High Winter Use (COGwh) Formula Winter Season

COGwh = RATIOh x CFw xCGwd + CGwo

High Winter Use (COGsh) Formula Summer Season

COGsh = RATIOh x CFs x CGsd + CGso
and

$$RATIOh = \frac{DCch}{DDch} \div \frac{DCc}{DDc}$$

and:

$$CFw = \frac{(WL:Sales + WH\ Sales)}{(RATIOl \times WL:Sales) + (RATIOh \times WH:Sales)}$$

$$CFs = \frac{(SL:Sales + SH:Sales)}{(RATIOl \times SL:Sales) + (RATIOh \times SH:Sales)}$$

$$CGwd = \frac{Dw}{W:Sales}$$

$$CGwo = \frac{CGw - Dw}{W:Sales}$$

$$CGsd = \frac{Ds}{S:Sales}$$

$$CGso = \frac{CGs - Ds}{S:Sales}$$

DCcl = Bcl * PLrate + (DDcl – Bcl) * REMrate

DCch = Bch * PLrate + (DDch- Bch) * REMrate

PLrate = PL/ PLmdcq

$$REMrate = \frac{(DCc - (Bc*PLrate))}{DDc - Bc}$$

$$DCc = \frac{(DC \times DDc)}{DD}$$

where:

Bc = The daily base load for all the Commercial and Industrial rate classes

Bch = The daily base load for the Commercial and Industrial rate classes G-41, G-42, G-43, G-44, G-45 and G-46.

Bcl = The daily base load for the Commercial and Industrial rate classes G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

CFs = Summer Season Commercial and Industrial gas cost correction factor.

CFw = Winter Season Commercial and Industrial gas cost correction factor.

CGs = The total cost of gas for the Summer Season for the Company’s firm sales customers as previously defined.

CGw = The total cost of gas for the Winter Season for the Company’s firm sales customers as previously defined.

DC =	The annual forecasted pipeline, storage and peaking demand charges plus the total production and storage capacity costs, as stated in Section 16(F).
DCc =	The Commercial and Industrial rate classes pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs.
DCch =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to Commercial and Industrial High Winter Use rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DCcl =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to the Commercial and Industrial Low Winter Use rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
DD =	Total peak design day determinants.
DDc =	The peak design day determinants allocated for all the Commercial and Industrial rate classes.
DDch =	The peak design day determinants for the Commercial and Industrial rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DDcl =	The peak design day determinants for the Commercial and Industrial rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
Ds =	The total Summer Demand charges as defined below.
Dw =	The total Winter Demand charges as previously defined.
PL =	The annual forecasted pipeline only demand charges
PLmdcq =	The maximum daily contract pipeline volume available to the Company.
PLrate =	The pipeline demand rate.
RATIOh =	Ratio of the average high Winter Use class Cost of Gas low load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
RATIOl =	Ratio of the average low Winter Use class Cost of Gas high load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
REMrate =	The weighted average demand rate for storage and peaking supplies.
S: Sales =	Forecasted sales volumes associated with the Summer Season.
SH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
SL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.
W:Sales =	Forecasted sales volumes associated with the Winter Season.
WH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
WL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.

H. Non-Core Sales Margins ("NCSM"). One hundred percent (100%) of margins from Off-System Sales and all revenues from Capacity Release will be credited to firm sales customers during the winter season through operation of the COG.

I. Gas Suppliers' Refunds. Account 5541-8048: Refunds from suppliers of gas, from upstream capacity suppliers and suppliers of product demand are credited to Account 5541-8048, "Commodity and Demand Refunds." Transfers from these accounts will reflect as a credit in the semiannual calculation of the COG to be calculated as follows:

Refund programs shall be initiated with each semiannual COG filing and shall remain in effect for a period of one year. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. Refunds shall be segregated by demand and commodity charges and distributed volumetrically, producing per unit refund that will return the principal amount with interest as calculated using the Company's average short-term cost of borrowing for the month to the average of the beginning and end of month balances of refunds. The Company shall track and report on all Account 5541-8048 activities as specified in Section 16(K).

J. Reconciliation Adjustments – Various Accounts.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Capacity Costs Allowable per Winter Season Formula shall be:

(1) Charges associated with upstream storage transmission capacity and product demand procured by the Company to serve firm load in the Winter Season, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Charges associated with peaking, downstream production and storage capacity to serve firm load dispatching costs, and other administrative and general expenses in connection with purchasing gas supplies in the Winter Season from the Company's most recent test year and allocated to firm sales service.

(3) Non-Core Sales Margins or economic benefits associated with returnable capacity release and off-system sales.

(4) Credits associated with firm Stand-by Gas Supply Service Monthly Reservation Charges, daily imbalance charges and fixed component of penalty charges billed transportation customers in the Winter peak Season.

(5) Winter Season Demand Cost carrying charges.

b. Gas Costs Allowable Per Winter Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter Season.

(2) Credit non-core commodity costs assigned to non-core customers to which the COGC does not apply, as defined in Section 16(H) (NCCCw).

(3) Inventory finance charges (FC).

(4) Winter Season commodity cost carrying charges.

c. Capacity Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with transmission capacity and product demand procured by the Company to serve firm load in the Summer Season

(2) Credits associated with daily imbalance charges and fixed component of penalty charges billed transportation customers in the Summer Season.

(3) Summer Season demand cost carrying charges.

d. Gas Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

(3) Summer Season commodity cost carrying charges.

e. Costs Allowable Per Bad Debt Formula shall be:

(1) Costs associated with uncollected gas costs, incurred by the Company to serve sales load. Such costs represent the bad debt expense related to the gas supply related write-off of sales customers and will be computed by multiplying actual gas costs by the Bad Debt Allowed Recovery Rate specified in Section 16(F). The reconciliation adjustment each season will be computed as the difference between the actual supply related bad debt revenues and the actual gas costs multiplied by the actual Bad Debt Allowed Recovery Rate as specified in Section 16(F).

(2) Account 1920-1743 – Annual Bad Debt, carrying charges.

2. Calculation of the Reconciliation Adjustments: These accounts contain the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Winter Season Gas Costs (Account 1920-1740) and Summer Season Gas Costs (Account 1920-1741), Account 1920-1740 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Winter Season Gas Cost for each Customer Classification, (COGwr, COGwl and COGwh) times monthly firm sales volumes for each Customer Classification, and the total costs allowable per the Winter Season gas cost formula. Account 1920-1741 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Summer Season Gas Cost for each Customer Classification, (COGsr, COGsl and COGsh) times monthly firm sales volumes for each Customer Classification, and the total gas costs allowable per the Summer Season demand formula.

Carrying Charges shall be calculated on the average monthly balance of each subaccount. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

The annual bad debt reconciliation adjustments Rbd shall be determined for use, incorporating the bad debt balances in Account 1920-1743.

The bad debt account balance contains the accumulated difference between the Bad Debt Allowed Recovery Rate for the applicable period multiplied by the actual gas costs and the actual supply related bad debt revenues for the Winter and Summer COG filings.

The Winter Season reconciliation shall be filed with the NHPUC no later than July 29 of each year.

The Summer Season reconciliation shall be filed with the NHPUC no later than January 31 of each year.

K. Working Capital Reconciliation Adjustments - Accounts 1163-1422 and 1163-1424.

1. The following definitions pertain to reconciliation adjustment calculations:

   a. Working Capital Demand Gas Costs Allowable per Winter Season Gas Formula shall be:

      (1) Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the Winter period, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

      (2) Carrying charges.

   b. Working Capital

      (1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter season.

      (2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

      (3) Carrying charges.

   c. Working Capital Demand Gas Costs Allowable per Summer Season Gas Formula shall be:

      (1) Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Summer Season.

      (2) Carrying charges.

   d. Working Capital Commodity Gas Costs Allowable per Summer Season Gas Formula shall be:

      (1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

      (2) Non-core commodity costs associated with non-core sales.

      (3) Carrying charges.

   e. The Winter and Summer Cost of Gas working capital allowances shall be calculated by applying the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F).

2. Calculation of the Reconciliation Adjustments

   a. Accounts 1163-1422 and 1163-1424 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance cost. The actual monthly working capital allowance shall be calculated by multiplying the actual gas costs times the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F), to the actual Direct Gas Costs allowable.

   b. The Winter Season working capital reconciliation adjustment (WCRw) shall be determined for use in the Winter Season Gas Cost calculations incorporating the Winter Season working

capital account 1163-1422. A Summer Season working capital reconciliation adjustment (WCRs) shall be determined for use in the Summer Season Gas Cost calculations incorporating the Summer Season working capital account 1163-1424 balance.

L. Application of COG to Bills: The Company will employ the COGs as follows: The COGs ($/therm) for each customer group for each season shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volume within the corresponding customer classification. The Cost of Gas will be applied to gas consumed on or after the first day of the month in which the cost of gas becomes effective.

M. Information Required to be Filed with the NHPUC.

1. Reconciliation Adjustments: The Company shall file with the NHPUC a seasonal reconciliation of gas costs and gas cost collections containing information in support of the reconciliation calculation set out in Sections 16(J) (2) and 16(K) (2). Such information shall include the complete list of gas costs recoverable through the COGC over the previous season. This seasonal reconciliation shall be filed with the respective seasonal COG reconciliation filing, along with complete documentation of the reconciliation adjustment calculations.

   Additionally, information pertaining to the Cost of Gas shall be filed with the NHPUC in accordance with the format established by the NHPUC. Reporting requirements include filing the Company's monthly calculation of the projected over or under-collection with the NHPUC, along with notification by the Company to the NHPUC of any revised COG for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month.

   The Company shall file with the NHPUC an annual reconciliation of bad debt expense and bad debt collections containing information in support of the reconciliation calculation set out in Sections 16(J) (1) and 16(J) (2). Such information shall detail the revenues collected as an allowance for bad debt, as well as the actual bad debt expense associated with gas cost recoverable through the COGC over the 12-month period ending April 30th. This annual reconciliation of bad debt expenses shall be filed with the Winter COG reconciliation filing, along with documentation.

2. Commercial and Industrial COG Ratio: The following factors will be filed annually by the Company for informational purposes. Significant changes in these factors signal the need to evaluate the COG ratios. These variables will assist in predicting significant shifting of the MBA-based escalator of gas costs and resulting changes in the COG ratios:

   a. The percentage of load migration from sales to transportation service in the Commercial and Industrial High and Low Winter Use classes.

   b. The ratio of delivered costs of winter supplies to pipeline delivered supplies.

   c. The July and August consumption for the Commercial and Industrial High and Low Winter classes as a percentage of their annual consumption.

N. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of this tariff, upon such terms that it may determine to be in the public interest.

2. The Company may, without further NHPUC action, adjust the approved COG upward or downward monthly based on the Company's calculation of the projected over or under-collection for the period, but the cumulative adjustments upward shall not exceed twenty-five percent (25%) of the approved COG.

3. The Company may, at any time, file with the NHPUC an amended COG.

4. The operation of the Cost of Gas Clause is subject to all powers of suspension and investigation vested in the NHPUC.

5. The Company shall file both seasonal COG filings on or before the first business day in September. The summer portion of the filing will include COG rates effective May 1 of the following year.

O. Reconciliation Adjustment Accounts.

1163-1422

Winter Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas working capital allowance revenues and Winter Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1163-1424

Summer Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas working capital allowance revenues and Summer Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1740

Winter Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas revenues and Winter Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1741

Summer Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas revenues and Summer Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1743

Annual Bad Debt Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Annual bad debt revenues and annual bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

5541-8048

Commodity and Demand Refunds: This account shall be used to record the refunds from upstream commodity supplies and suppliers of product commodity and transfers of credits in the semiannual calculation of the COG as well as to record the refunds from upstream capacity supplies and suppliers of product demand and transfer of credits in the semiannual calculation of the COG. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

P. Firm Transportation Cost of Gas Charge. To permit the Company to charge its firm transportation customers with a portion of the cost of gas produced by the Company between November 1 and April 30 of each year, there is a Firm Transportation Cost of Gas Charge ("FTCG") which applies to all firm transportation billed under this tariff. This volumetric charge is to compensate firm sales customers for the increase in gas costs, through the use of supplemental liquid fuels, attributable to firm transportation customers during the Winter Period.

1. Application. The FTCG will be calculated for the Winter Period, defined as the period from November 1 through April 30. The FTCG will be applied to billings commencing with the first November revenue billing cycle

2. Purpose. The amount of the FTCG is the estimated liquid costs used for pressure support purposes multiplied by the transportation throughput as a percentage of the total system throughput for the Winter Period. The resulting amount shall be adjusted by the prior period over or under collection, if any, and shall be recovered over the estimated total transportation throughput subject to the FTCG to yield a per therm volumetric charge. The FTCG shall be computed to the nearest one hundredth cent per therm and shown separately on customers' bills. At the conclusion of the Winter Period, the Company will calculate the extent that the FTCG revenues are greater or lesser than actual unit cost. The revenue and liquid costs will be reconciled so that all liquids costs shall be collected from either firm sales or firm transportation customers.

3. Changes. The amount of the FTCG may be changed within the period whenever the unit cost materially deviates from the anticipated unit cost

4. Reporting. The Company shall submit to the New Hampshire Public Utilities Commission, on or before the first business day in September, a copy of the FTCG computation. A reconciliation of the prior period under/over collection will be submitted to the New Hampshire Public Utilities Commission no later than July 29.

Q. Fixed Price Option Program. Fixed Price Option Program. An alternative to the traditional Winter Period cost of gas pricing mechanism may be elected by a residential customer (rates R-1, R-3, R-4, R-5 or R-6) pursuant to the Company's Fixed Price Option Program (the "Program"). The Company may offer up to 50% of its weather normalized firm sales for the prior Winter Period under the Program. The cost of gas rate offered under the Program will remain fixed for all Winter Period deliveries commencing November 1 and ending April 30. The Company shall submit to the New Hampshire Public Utilities Commission on or before September 1 of each year a copy of the fixed price option computation. Once elected, customers must remain on the Program for the duration of the Winter Period, unless service is terminated. There are no maximum or minimum usage levels. No sign up fees apply.

16.2 COST OF GAS CLAUSE – KEENE DIVISION

A. Purpose. To permit the Company to charge its customers in the Keene Division with the cost of gas purchased or produced. A cost of gas rate will be applied to all firm gas billed under this tariff as calculated on the appropriate pages.

B. Application. A cost of gas rate will be calculated for the winter heating period, defined as the period from November 1 through April 30, and a cost of gas rate will be calculated for the summer period, defined as the period from May 1 through October 31.

The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

A. Purpose. The purpose of the Local Distribution Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), ~~Lost Revenues Adjustment Mechanism~~ Revenue Decoupling Adjustment Clause ~~related to the Energy Efficiency Programs~~ ("~~LRAM~~RDAC"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), recover gas restructuring expenses ("GRE"), rate case expenses ("RCE"), Residential Low Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time.

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	**CC 17(C)**	**~~LRAM~~RDAC 17(C.1)**	**ES 17(D)**	**GRE 17(E)**	**RCE 17(F)**	**RLIAP 17(G)**
Residential Non-Space Heating – R-1, R-5	~~1~~2	~~1~~2	X	N/A	~~1~~2	X
Residential Space Heating – R-3, R-4, R-6, R-7	2~~1~~	~~1~~2	X	N/A	~~1~~2	X
Small C&I – G-41, G-51, G-44, G-55	2~~1~~	~~1~~2	X	X	~~1~~2	X
Medium C&I – G-42, G-52, G-45, G-56	2~~1~~	~~1~~2	X	X	~~1~~2	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	2~~1~~	~~1~~2	X	X	~~1~~2	X

Notes:
N/A Not applicable
X Applicable to all
1 ~~As ordered by the NHPUC~~ Applicable to Non-Managed Expansion Program Customers
2 As ordered by the NHPUC

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the ~~New Hampshire Public Utilities~~ Commission ~~(the "Commission")~~ as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

C.1 ~~Lost Revenue Adjustment Mechanism Allowable for LDAC.~~Revenue Decoupling Adjustment Clause

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on a semi-annual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's Revenue Decoupling Adjustment eliminates the link between customer sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

2. Effective Date: The Winter Season Revenue Decoupling Adjustment Factor ("RDAF") for the Winter Season shall be effective on the first day of each Winter Season as defined herein. The Summer Season RDAF shall become effective on the first day of each Summer Season as defined herein.

3. Applicability: The Revenue Decoupling Adjustment Factor shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC.

4. Definitions: The following definitions shall apply throughout the RDAC:

   a. Actual Base Revenue per Customer is the actual revenue derived from the Company's base rates divided by the Actual N~~n~~umber of C~~c~~ustomers for a given season for a Customer Class Group.

   b. Actual Number of Customers is the actual number of customers for the applicable Customer Class Group for the most recently completed Winter Season or Summer Season. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for ~~bills for~~ a given season for a Customer Class Group and dividing by the number of months in each Season.

c. -Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

d. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment amounts. The three Customer Class Groups are as follows:

(1) The Residential Non-Heating Customer Class Group (CG1) shall consist of all customers taking service pursuant to the Company's residential non-heating rate schedule R-1.

(2) The Residential Heating Customer Class Group (CG2) shall consist of all customers taking service pursuant to the Company's residential heating rate schedules R-3, and R-4.

(3) The Commercial and Industrial Customer Class Group (CG3) shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-51, G-52, G-53 and G-54.

e. Summer Season is the continuous period from May 1 through October 31.

f. Winter Season is the continuous period from November 1 through April 30.

g. Benchmark Base Revenue per Customer is the allowed average revenue per Customer for a given season for a Customer Class Group, reflecting the base revenue from the Company's base rate case or other proceeding that results in an adjustment to base rates. The following are the Benchmark Base Revenue per Customer values as approved by the Commission in Docket No. DG 17-048:

	Benchmark Base Revenue per Customer	
Customer Class Group	**Winter Season**	**Summer Season**
Residential Non-Heating (CG1)	$165.77	$145.53
Residential Heating (CG2)	$433.98	$210.90
Commercial and Industrial (CG3)	$2,200.52	$894.95

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Winter Season and Summer Season, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next corresponding season.

The Revenue Decoupling Adjustment shall be determined by calculating the difference between the A~~a~~ctual Base Revenue per Customer and the Benchmark Base Revenue per Customer, and multiplying that difference by the Actual Number of Customers for the applicable Customer Class Group. The Revenue Decoupling Adjustment shall equal the sum of the adjustments calculated for each of the three Customer Class Groups and shall include a reconciliation component.

The total Revenue Decoupling Adjustment determined in accordance with Section 5.0 may not exceed plus or minus five percent (~~±~~+/-5%) of total base revenues from firm Rate Classes for the most recent corresponding Winter or Summer Season. To the extent that the application of the Revenue Cap results in a Revenue Decoupling Adjustment that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the Revenue Decoupling Reconciliation for recovery in the subsequent year during the corresponding Winter or Summer Season. Carrying charges shall be calculated on the average deferred balance using the prime lending rate and then added to the end-of-month balance.

b. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CG=1}^{CG=3} \left[\left(BRPC_{T-1}^{CG} - ARPC_{T-1}^{CG}\right) x\ ACUSTS_{T-1}^{CG}\right]$$

If
$RD < (5\%\ x\ DIST\ REV_T)$
And
$RD > (-5\%\ x\ DIST\ REV_T)$

Then
$DEF_{incm} = 0$
And:
$DEF_{rec} = Lower\ of\ (DEF_{balp)}\ or\ \left((5\%\ x\ DIST\ REV_T) - RD\right)$
And:
$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} - DEF_{rec}$
And:
$$RDAF = \frac{RD + RF_{rd} + DEF_{rec}}{P: Thru_T}$$

Else:
$DEF_{incm} = RD - (5\%\ x\ DIST\ REV_T)$
And:
$DEF_{rec} = 0$
And
$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} + DEF_{incm}$
And
$$RDAF = \frac{(5\%\ x\ DIST\ REV_T) + RF_{rd}}{P: Thru_T}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CG}$:	The A~~a~~ctual N~~n~~umber of C~~c~~ustomers for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1). Actual number of customers for each Winter or Summer Season shall be the average number monthly customers in that season, calculated by summing the number of equivalent bills~~billed customers~~ in each month of the most recently completed Winter or Summer Season, and dividing by the number of months in the Season.
$ARPC_{T-1}^{CG}$:	The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1), as defined in Section 4.0. For purposes of calculating the Actual Base Revenue per Customer, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.
$BRPC_{T-1}^{CG}$:	The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section 4.0(A) for the most recently completed Winter or Summer Season (T-1).
cg	Customer Class Groups as defined in Section 4.0(D).
DEF_{bal}	The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.
DEF_{incm}	The amount of Revenue Decoupling that must be deferred in the current year based on the difference between plus or minus five percent (+/-5%) of total distribution revenues as determined in accordance with the definition of DIST REV_T in Section 5.0(B).
DEF_{rec}	The amount of deferrals the Company may recover in the current Winter or Summer Season.
P: $Thru:_T$	Forecast Throughput Volumes inclusive of all firm tariff throughput for the Winter or Summer Season.
RD	The Revenue Decoupling adjustment to revenues.
$RDAF_T$:	The Revenue Decoupling Adjustment Factor for the Winter or Summer Season.
RF_{rd}:	Revenue Decoupling Reconciliation Adjustment as described in Section 6.0.
DIST REV_T	The Distribution revenues from all firm rate classes during the most recent Winter or Summer Season.

6. Calculation of the Reconciliation Adjustments

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Winter Season, as calculated by multiplying the Winter Season RDAF times the Winter Season firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues for the Winter Season, plus carrying charges on the average monthly balance using the prime lending rate.

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Summer Season, as calculated by multiplying the Summer Season Revenue Decoupling Adjustment Clause times the Summer Season firm throughput, and the Revenue Decoupling Adjustment allowed revenues for the Summer Season, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

The RDAF ($ per therm) shall be truncated at the nearest one one-hundredth of a cent per therm. The RDAF for the Winter Season will be applied usage in the next Winter Season and the RDAF for the Summer Season will be applied to usage in the next Summer Season. The RDAF will be applied to the monthly firm tariff throughput for each customer.

8. Information to be Filed with the Commission

Information pertaining to the RDAC will be filed with the Commission ninety (90) days prior to the effective dates of the November 1 Winter Season and May 1 Summer Season RDAF. Such information shall include:

a. the calculation of the applicable revenue decoupling revenue adjustment

b. the calculation of the revenue decoupling reconciliation adjustment.;

c. the calculation of annually updated Benchmark Base Revenue per Customer to be utilized in the upcoming Summer and Winter Seasons.

~~D. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Lost Revenue Adjustment Rate, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers lost revenue related to Energy Efficiency programs, pursuant to Order No. 25,932 in Docket DE 15-137, Energy Efficiency Resource Standard.~~

~~E. Applicability: A Lost Revenue Adjustment charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the New Hampshire Public Utilities Commission (the "Commission") as determined in accordance with the provision of this rate schedule. Such Lost Revenue Adjustment charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.~~

~~F. Calculation of Lost Revenue Adjustment: The Lost Revenue Adjustment for each Rate Category will be derived by dividing the projected annual lost revenue, plus the reconciliation balance, by forecast firm annual throughput. The reconciliation balance shall reflect both actual and projected data, as necessary, through October of the prior rate period.~~

~~G. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the Lost Revenue Adjustment Rate applicable to each Rate Category during the next subsequent twelve month period commencing with the calendar month of November.~~

~~H. Reconciliation Adjustment: Account xxxx-xxxx shall contain the cumulative difference between the Lost Revenue Adjustment Rate revenues collected and actual costs, plus carrying charges. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.~~

~~I.~~D. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

   The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH ~~and pond~~. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

~~J.~~E. Expenses Related to Gas Restructuring.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates on an annual basis for the recovery of NHPUC-approved costs associated with the Gas Restructuring Collaborative (Docket DE 98-124).

2. Applicability: The Gas Restructuring Expenses ("GRE") shall be applied to all firm tariffed customers eligible to receive delivery service from the Company as determined in accordance with the provisions of Section 17(F) of this clause. The GRE shall be determined annually by the Company as defined below, subject to review and approved by the NHPUC as provided for in this clause.

3. GRE Allowable for LDAC: Costs associated with the Gas Restructuring Collaborative (DE 98-124), including, but not limited to, any legal, consulting, customer focus group(s) and survey(s), customer education campaign(s), materials and advertising, subject to review and approval by the NHPUC.

4. Effective Date of GRE Charge: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the GRE applicable to all consumption of tariffed customers eligible to receive delivery service for the subsequent twelve month period commencing with the calendar month of November.

5. Definition: Gas Restructuring Initiatives are activities facilitating the development, design and implementation of unbundled services for all customers.

6. GRE Factor Formula:

$$GREF = \frac{GRE + RA_{GRE}}{A{:}\ TPev}$$

where:

A:Tpev Forecast Annual Throughput Volumes of all tariffed customers eligible to receive firm delivery-only service from the Company.

GRE Gas Restructuring Expenses as defined in Section 17(F).05.

RA_{GRE} Gas Restructuring Expense Reconciliation Adjustment - Account 1920-1744, inclusive of the associated Account 1920-1744 interest, as outlined in Section 17(E)(7).

7. Reconciliation Adjustments: Account 1920-1744 shall contain the accumulated difference between revenues toward Gas Restructuring Expenses as calculated by multiplying the Gas Restructuring Expense Factor ("GREF") times monthly volumes of customers eligible to receive firm delivery service and Gas Restructuring expenses allowed, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end-of-month balance.

8. Application of GREF to Bills: The GREF ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the Gas Restructuring Expenses shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual GREF filing shall be required on or before the first business day in September of each year. The GREF filing shall contain the calculation of the new annual GREF to become effective November 1 and shall include the updated annual Gas Restructuring Expense reconciliation balance.

~~K.~~F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between

the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

~~L.~~G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in

the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A\!: TPev}$$

where:

A: Tpev — Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

RLIAP — RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{RLIAP} — RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

~~M.~~H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

~~N.~~I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{x} = CC^{x} + \cancel{LRAM^{x}}\ RDAC^{x} + ES + GREF^{x} + RCE + RLIAP$$

and:

$$ES^{x} = RHS + MGP$$

where:

$LDAC^{x}$ = Annualized class specific LDAC.

CC^X = Annualized class specific CC or EE Charge.

~~$LRAM^X$~~ $RDAC^X$ = Annualized class specific ~~LRAM~~RDAC.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^X$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

~~O.~~J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

~~P.~~K. Other Rules.

1. (1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

~~Q.~~L. Amendments to Uniform System of Accounts.

1920-1744 **Gas Restructuring Expense Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(E).

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(D).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(G).

1163-1756 **Lost Revenue Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C.1).

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

2. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

3. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

4. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

5. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

6. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

7. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

8. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

9. Feedstock Gas: Is defined as natural gas used as a raw material for its chemical properties in creating an end product

10. Process Gas: Is defined as gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels

11. Boiler Fuel: Is considered to be natural gas used as a fuel for the generation of steam or electricity including the utilization of gas turbines for the generation of electricity

12. Alternate Fuel Capabilities: Is defined as a situation where an alternate fuel could have been utilized whether or not the facilities for such use have actually been installed, provided however, where the use of natural gas is for plant protection, feedstock or process uses and the only alternate fuel is propane or other gaseous fuel, then the consumer will be treated as if he had no alternate fuel capability.

B. POLICY

In the event that, due to gas supply restrictions or capacity constraints, the Company is unable to deliver the total requirements of its firm, sales or transportation rate customers, the available volumes of gas will be allocated to the Company's firm rate customers in accordance with the provisions of this policy. In the event that the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of the customer, customer shall be compensated for such emergency gas at the customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.

As curtailment becomes necessary through each succeeding category, the Company will implement full or partial curtailment of a customer, or by groups of customers, taking into consideration customer load characteristics, the Company's delivery system design and Company load characteristics in a manner which is believed to be in the best interests of customers in general.

C. PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories:

1. Company use for fuel and lost and unaccounted for

2. Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

3. Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and

agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

4. Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

5. Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (6), or (7)

6. Firm sales or transportation service including the transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

7. Firm sales or transportation service including transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

D. STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

E. PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service.

II. RATE SCHEDULES

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1

Availability

This rate is available to all residential customers who do not have gas space heating equipment, who consume less than 80% of their normal usage in the six winter months of November through April and whose usage does not exceed 100 therms in any winter month. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.7176~~5090~~ per day or $21.50~~15.27~~ per 30 day month
Winter Period:	All therms per 30 day month at $0.2446~~018~~ per therm
Summer Period:	All therms per 30 day month at $0.2446~~018~~ per therm

~~*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.~~

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause~~ (LDAC)~~, as in effect from time to time and on file with ~~The ~~the ~~New Hampshire Public Utilities ~~Commission~~ (NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time,~~,~~ with the ~~New Hampshire Public Utilities~~ Commission.

2 RESIDENTIAL HEATING RATE:
CLASSIFCATION NO. R-3

Availability

This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.8500~~7367~~ per day or $25.50~~22.10~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5201~~3495~~ per therm
	All over 100 therms per 30 day month at $0.4176~~2892~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.5201~~3495~~ per therm
	All over 20 therms per 30 day month at $0.4176~~2892~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time,~~,~~ with the ~~New Hampshire Public Utilities~~ Commission.

3 LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4

Availability

This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.3400~~2947~~ per day or $10.20~~8.84~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2080~~1398~~ per therm
	All over 100 therms per 30 day month at $0.1670~~1156~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.2080~~1398~~ per therm
	All over 20 therms per 30 day month at $0.1670~~1156~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

For those customers qualifying for the program this rate R-4 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time.~~,~~ with the ~~New Hampshire Public Utilities~~ Commission.

4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Residential Non Heating Rate R-1.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.9317~~6617~~ per day or $27.95~~19.85~~ per 30 day month
Winter Period:	All therms per 30 day month at $0.31802~~623~~ per therm
Summer Period:	All therms per 30 day month at $0.31802~~623~~ per therm

~~*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.~~

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with ~~The New Hampshire Public Utilities~~ the Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time~~,~~, with the ~~New Hampshire Public Utilities~~ Commission.

5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program projects area who otherwise would have qualified for Residential Heating Rate R-3.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.1050~~0.9577~~ per day or $33.15~~28.73~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.6761~~4544~~ per therm
	All over 100 therms per 30 day month at $0.5429~~3760~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.6761~~4544~~ per therm
	All over 20 therms per 30 day month at $0.5429~~3760~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-3.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

6 MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Low Income Residential Heating Rate R-4.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $0.4420~~3831~~ per day or $13.26~~11.49~~ per 30 day month

Winter Period: First 100* therms per 30 day month at $0.2704~~1817~~ per therm

All over 100 therms per 30 day month at $0.2171~~1503~~ per therm

Summer Period: First 20* therms per 30 day month at $0.2704~~1817~~ per therm

All over 20 therms per 30 day month at $0.2171~~1503~~ per therm

***The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of

these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Low Income Residential Heating Rate R-4.

For those customers qualifying for the program this rate R-7 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-7 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-6. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

7 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFCATION NO. G-41

Availability

This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company’s records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537~~1.6120~~ per day or $55.61~~48.36~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5689~~3965~~ per therm
	All over 100 therms per 30 day month at $0.3130~~2663~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.5689~~3965~~ per therm
	All over 20 therms per 30 day month at $0.3130~~2663~~ per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE
CLASSIFICATION NO. G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $5.3197~~4.8360~~ per day or $159.59~~145.08~~ per 30 day month

Winter Period:	First 1000* therms per 30 day month at $0.4458~~3606~~ per therm
	All over 1000 therms per 30 day month at $0.2952~~2402~~ per therm
Summer Period:	First 400* therms per 30 day month at $0.4458~~3606~~ per therm
	All over 400 therms per 30 day month at $0.2952~~2402~~ per therm

***The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

DATED: April 28, 2017 — ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 — TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. ~~-~~In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter: $22.8290~~20.7537~~ per day or $684.87~~622.61~~ per 30 day month

Winter Period: All therms per 30 day month at $0.2684~~2216~~ per therm

Summer Period: All therms per 30 day month at $0.1227~~1013~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause~~ (LDAC)~~, as in effect from time to time and on file with the N~~ew Hampshire Public Utilities~~ Commission~~ (NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44

Availability
This rate is Mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-41.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097~~0956~~ per day or $72.29~~62.87~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.7396~~5155~~ per therm
	All over 100 therms per 30 day month at $0.4069~~3462~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.7396~~5155~~ per therm
	All over 20 therms per 30 day month at $0.4069~~3462~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-41.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-42.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $6.9157~~2868~~ per day or $207.47~~188.60~~ per 30 day month

Winter Period: First 1000* therms per 30 day month at $0.5795~~4688~~ per therm

All over 1000 therms per 30 day month at $0.3838~~3123~~ per therm

Summer Period: First 400* therms per 30 day month at $0.5795~~4688~~ per therm

All over 400 therms per 30 day month at $0.3838~~3123~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. ~~–~~In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-42.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-43.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:$29.6777~~26.9798~~ per day or $890.33~~809.39~~ per 30 day month

Winter Period: All therms per 30 day month at $0.2684~~2881~~ per therm

Summer Period: All therms per 30 day month at $0.1595~~1317~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause~~ (LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities ~~Commission~~ (NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74-A of this Tariff for firm rate schedules ~~the Firm Rate Scheduleswhich present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-43.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $1.8537~~6120~~ per day or $55.61~~48.36~~ per 30 day month

Winter Period: First 100* therms per 30 day month at $0.3460~~2390~~ per therm

All over 100 therms per 30 day month at $0.2060~~1553~~ per therm

Summer Period: First 100* therms per 30 day month at $0.3460~~2390~~ per therm

All over 100 therms per 30 day month at $0.2060~~1553~~ per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-52

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter: $5.3197~~4.8360~~ per day or $159.59~~145.08~~ per 30 day month

Winter Period:	First 1000* therms per 30 day month at $0.2739~~2052~~ per therm
	All over 1000 therms per 30 day month at $0.1897~~1367~~ per therm
Summer Period:	First 1000* therms per 30 day month at $0.2155~~1487~~ per therm
	All over 1000 therms per 30 day month at $0.1192~~0845~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE
CLASSIFICATION NO. G-53

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge ;

Customer Charge Per Meter:$23.4937~~21.3580~~ per day or $704.81~~640.74~~ per 30 day month

Winter Period: All therms per 30 day month at $0.1741~~1434~~ per therm

Summer Period: All therms per 30 day month at $0.0835~~0688~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-54

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $23.4937~~21.3580~~ per day or $704.81~~640.74~~ per 30 day month

Winter Period: All therms per 30 day month at $0.0667~~0547~~ per therm

Summer Period: All therms per 30 day month at $0.0362~~0297~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-55

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-51.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097~~0956~~ per day or $72.29~~62.87~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.4498~~3107~~ per therm
	All over 100 therms per 30 day month at $0.2678~~2019~~ per therm
Summer Period:	First 100* therms per 30 day month at $0.4498~~3107~~ per therm
	All over 100 therms per 30 day month at $0.2678~~2019~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this

tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-51.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-56

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-52.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter: $6.9157~~6.2868~~ per day or $207.47~~188.60~~ per 30 day month

Winter Period:	First 1000* therms per 30 day month at $0.3561~~2668~~ per therm
	All over 1000 therms per 30 day month at $0.2466~~1777~~ per therm
Summer Period:	First 1000* therms per 30 day month at $0.2802~~1933~~ per therm
	All over 1000 therms per 30 day month at $0.1550~~1099~~ per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-52.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFCATION NO. G-57

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-53.

Character of Service

Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge ;

Customer Charge Per Meter:$30.5417~~27.7654~~ per day or $916.25~~832.96~~ per 30 day month

Winter Period: All therms per 30 day month at $0.2263~~1864~~ per therm

Summer Period: All therms per 30 day month at $0.1086~~0894~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-53.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

20 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-58

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-54.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:$30.541~~727.7654~~ per day or $916.25~~832.96~~ per 30 day month

Winter Period: All therms per 30 day month at $0.0867~~0711~~ per therm

Summer Period: All therms per 30 day month at $0.0471~~0386~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-54.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

21 OUTDOOR GAS LIGHTING

Availability

This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services. Service under this rate is available at those locations which were receiving service hereunder as of July 1, 2015, and which have continuously received service hereunder since that date.

Rate Per Light Per Month	$11.34

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

22 FIRM RATE SCHEDULES

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$21.50			$ 21.50	$ 21.50			$ 21.50
All therms	$ 0.2446	$ 0.4002	$ 0.0640	$ 0.7088	$ 0.2446	$ 0.4368	$ 0.0640	$ 0.7454
Residential Heating - R-3								
Customer Charge per Month per Meter	$25.50			$ 25.50	$ 25.50			$ 25.50
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.5201	$ 0.4002	$ 0.0640	$ 0.9843	$ 0.5201	$ 0.4368	$ 0.0640	$ 1.0209
All therms over the first block per month at	$ 0.4176	$ 0.4002	$ 0.0640	$ 0.8818	$ 0.4176	$ 0.4368	$ 0.0640	$ 0.9184
Residential Heating - R-4								
Customer Charge per Month per Meter	$10.20			$ 10.20	$ 10.20			$ 10.20
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2080	$ 0.4002	$ 0.0640	$ 0.6722	$ 0.2080	$ 0.4368	$ 0.0640	$ 0.7088
All therms over the first block per month at	$ 0.1670	$ 0.4002	$ 0.0640	$ 0.6312	$ 0.1670	$ 0.4368	$ 0.0640	$ 0.6678
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$55.61			$ 55.61	$ 55.61			$ 55.61
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.5689	$ 0.3961	$ 0.0450	$ 1.0100	$ 0.5689	$ 0.4206	$ 0.0450	$ 1.0345
All therms over the first block per month at	$ 0.3130	$ 0.3961	$ 0.0450	$ 0.7541	$ 0.3130	$ 0.4206	$ 0.0450	$ 0.7786
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$159.59			$ 159.59	$ 159.59			$ 159.59
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4458	$ 0.3961	$ 0.0450	$ 0.8869	$ 0.4458	$ 0.4206	$ 0.0450	$ 0.9114
All therms over the first block per month at	$ 0.2952	$ 0.3961	$ 0.0450	$ 0.7363	$ 0.2952	$ 0.4206	$ 0.0450	$ 0.7608
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$684.87			$ 684.87	$ 684.87			$ 684.87
All therms over the first block per month at	$ 0.2684	$ 0.3961	$ 0.0450	$ 0.7095	$ 0.1227	$ 0.4206	$ 0.0450	$ 0.5883
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$55.61			$ 55.61	$ 55.61			$ 55.61
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.3460	$ 0.4145	$ 0.0450	$ 0.8055	$ 0.3460	$ 0.4574	$ 0.0450	$ 0.8484
All therms over the first block per month at	$ 0.2060	$ 0.4145	$ 0.0450	$ 0.6655	$ 0.2060	$ 0.4574	$ 0.0450	$ 0.7084
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$159.59			$ 159.59	$ 159.59			$ 159.59
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2739	$ 0.4145	$ 0.0450	$ 0.7334	$ 0.2155	$ 0.4574	$ 0.0450	$ 0.7179
All therms over the first block per month at	$ 0.1897	$ 0.4145	$ 0.0450	$ 0.6492	$ 0.1192	$ 0.4574	$ 0.0450	$ 0.6216
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$704.81			$ 704.81	$ 704.81			$ 704.81
All therms over the first block per month at	$ 0.1741	$ 0.4145	$ 0.0450	$ 0.6336	$ 0.0835	$ 0.4574	$ 0.0450	$ 0.5859
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$704.81			$ 704.81	$ 704.81			$ 704.81
All therms over the first block per month at	$ 0.0667	$ 0.4145	$ 0.0450	$ 0.5262	$ 0.0362	$ 0.4574	$ 0.0450	$ 0.5386

23 FIRM RATE SCHEDULES - MANAGED EXPANSION PROGRAM

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate
Residential Non Heating - R-5								
Customer Charge per Month per Meter	$27.95			$ 27.95	$ 27.95			$ 27.95
All therms	$ 0.3180	$ 0.4002	$ 0.0640	$ 0.7822	$ 0.3180	$ 0.4368	$ 0.0640	$ 0.8188
Residential Heating - R-6								
Customer Charge per Month per Meter	$33.15			$ 33.15	$ 33.15			$ 33.15
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.6761	$ 0.4002	$ 0.0640	$ 1.1403	$ 0.6761	$ 0.4368	$ 0.0640	$ 1.1769
All therms over the first block per month at	$ 0.5429	$ 0.4002	$ 0.0640	$ 1.0071	$ 0.5429	$ 0.4368	$ 0.0640	$ 1.0437
Residential Heating - R-7								
Customer Charge per Month per Meter	$13.26			$ 13.26	$ 13.26			$ 13.26
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2704	$ 0.4002	$ 0.0640	$ 0.7346	$ 0.2704	$ 0.4368	$ 0.0640	$ 0.7712
All therms over the first block per month at	$ 0.2171	$ 0.4002	$ 0.0640	$ 0.6813	$ 0.2171	$ 0.4368	$ 0.0640	$ 0.7179
Commercial/Industrial - G-44								
Customer Charge per Month per Meter	$72.29			$ 72.29	$ 72.29			$ 72.29
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.7396	$ 0.3961	$ 0.0450	$ 1.1807	$ 0.7396	$ 0.4206	$ 0.0450	$ 1.2052
All therms over the first block per month at	$ 0.4069	$ 0.3961	$ 0.0450	$ 0.8480	$ 0.4069	$ 0.4206	$ 0.0450	$ 0.8725
Commercial/Industrial - G-45								
Customer Charge per Month per Meter	$207.47			$ 207.47	$ 207.47			$ 207.47
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.5795	$ 0.3961	$ 0.0450	$ 1.0206	$ 0.5795	$ 0.4206	$ 0.0450	$ 1.0451
All therms over the first block per month at	$ 0.3838	$ 0.3961	$ 0.0450	$ 0.8249	$ 0.3838	$ 0.4206	$ 0.0450	$ 0.8494
Commercial/Industrial - G-46								
Customer Charge per Month per Meter	$890.33			$ 890.33	$ 890.33			$ 890.33
All therms over the first block per month at	$ 0.2684	$ 0.3961	$ 0.0450	$ 0.7095	$ 0.1595	$ 0.4206	$ 0.0450	$ 0.6251
Commercial/Industrial - G-55								
Customer Charge per Month per Meter	$72.29			$ 72.29	$ 72.29			$ 72.29
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.4498	$ 0.4145	$ 0.0450	$ 0.9093	$ 0.4498	$ 0.4574	$ 0.0450	$ 0.9522
All therms over the first block per month at	$ 0.2678	$ 0.4145	$ 0.0450	$ 0.7273	$ 0.2678	$ 0.4574	$ 0.0450	$ 0.7702
Commercial/Industrial - G-56								
Customer Charge per Month per Meter	$207.47			$ 207.47	$ 207.47			$ 207.47
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.3561	$ 0.4145	$ 0.0450	$ 0.8156	$ 0.2802	$ 0.4574	$ 0.0450	$ 0.7826
All therms over the first block per month at	$ 0.2466	$ 0.4145	$ 0.0450	$ 0.7061	$ 0.1550	$ 0.4574	$ 0.0450	$ 0.6574
Commercial/Industrial - G-57								
Customer Charge per Month per Meter	$916.25			$ 916.25	$ 916.25			$ 916.25
All therms over the first block per month at	$ 0.2263	$ 0.4145	$ 0.0450	$ 0.6858	$ 0.1086	$ 0.4574	$ 0.0450	$ 0.6110
Commercial/Industrial - G-58								
Customer Charge per Month per Meter	$916.25			$ 916.25	$ 916.25			$ 916.25
All therms over the first block per month at	$ 0.0867	$ 0.4145	$ 0.0450	$ 0.5462	$ 0.0471	$ 0.4574	$ 0.0450	$ 0.5495

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24 FIRM RATE SCHEDULES - OUTDOOR GAS LIGHTING

Outdoor Gas Lighting	
Per Light Per Month	$11.34

25 ANITCIPATED COST OF GAS

Anticipated Cost of Gas		
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017		
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)		
(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 7,527,898	
Supply Costs:	49,523,042	
Storage Gas:		
Demand, Capacity:	$ 941,660	
Commodity Costs:	4,026,000	
Produced Gas:	1,797,499	
Hedged Contract (Saving)/Loss	-	
Hedge Underground Storage Contract (Saving)/Loss	-	
Unadjusted Anticipated Cost of Gas		$ 63,816,099
Adjustments:		
Prior Period (Over)/Under Recovery (as of 05/01/15)	$ 2,690,610	
Interest	14,641	
Prior Period Adjustments	-	
Broker Revenues	(1,374,947)	
Refunds from Suppliers	-	
Fuel Financing	-	
Transportation CGA Revenues	(29,471)	
Interruptible Sales Margin	-	
Capacity Release and Off System Sales Margins	(5,448,856)	
Hedging Costs	-	
Fixed Price Option Administrative Costs	41,972	
Total Adjustments		(4,106,050)
Total Anticipated Direct Cost of Gas		$ 59,710,049
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Unadjusted Anticipated Cost of Gas 11/01/15 - 04/30/16	$ 63,816,099	
Working Capital Rate: Lead Lag Days / 365	0.0391	
Prime Rate	3.50%	
Working Capital Percentage	0.137%	
Working Capital	$ 87,342	
Plus: Working Capital Reconciliation (Acct 142.20)	(33,597)	
Total Working Capital Allowance		53,745
Bad Debt:		
Total Unadjusted Anticipated Cost of Gas 11/01/15 - 04/30/16	$ 63,816,099	
Less: Refunds	-	
Plus: Total Working Capital	53,745	
Plus: Prior Period (Over)/Under Recovery	2,690,610	
Subtotal	$ 66,560,454	
Bad Debt Percentage	4.04%	
Bad Debt Allowance	$ 2,689,042	
Plus: Bad Debt Reconciliation (Acct 175.52)	(37,241)	
Total Bad Debt Allowance		$ 2,651,801
Production and Storage Capacity		$ 1,980,428
Miscellaneous Overhead (11/01/15 - 04/30/16)	$ 13,170	
Times Winter Sales	90,536	
Divided by Total Sales	112,609	
Miscellaneous Overhead		10,589
Total Anticipated Indirect Cost of Gas		$ 4,696,563
Total Cost of Gas		$ 64,406,611

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26 CALCULATION OF FIRM SALES COST OF GAS RATE

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas		$ 59,710,049		
Projected Prorated Sales (11/01/16 - 04/30/17)		89,920,078		
Direct Cost of Gas Rate			$ 0.6640	per therm
Demand Cost of Gas Rate		$ 8,469,558	$ 0.0942	per therm
Commodity Cost of Gas Rate		55,346,541	$ 0.6155	per therm
Adjustment Cost of Gas Rate		(4,106,050)	$ (0.0457)	per therm
Total Direct Cost of Gas Rate		$ 59,710,049	$ 0.6640	per therm
Total Anticipated Indirect Cost of Gas		$ 4,696,563		
Projected Prorated Sales (11/01/16 - 04/30/17)		89,920,078		
Indirect Cost of Gas			$ 0.0522	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/16			**$ 0.7162**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/16		**COGwr**	**$ 0.7162**	**/therm**
Change in rate due to change in under/over recovery			**$ (0.0723)**	
RESIDENTIAL COST OF GAS RATE - 12/01/2016		**COGsr**	**$ 0.6439**	**/therm**
Change in Rate due to change in under/over recovery			**$ 0.0837**	
RESIDENTIAL COST OF GAS RATE - 01/01/2017		**COGwr**	**$ 0.7276**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1264)**	
RESIDENTIAL COST OF GAS RATE - 2/1/2017		**COGwr**	**$ 0.6012**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1171)**	
RESIDENTIAL COST OF GAS RATE - 3/1/2017		**COGwr**	**$ 0.4841**	**/therm**
	Maximum	(COG + 25%)	$ 0.8953	
C&I LOW WINTER USE COST OF GAS RATE - 11/01/16		**COGwl**	**$ 0.7305**	**/therm**
Change in rate due to change in under/over recovery			**$ (0.0723)**	
C&I LOW WINTER USE COST OF GAS RATE - 12/01/2016		**COGsl**	**$ 0.6582**	**/therm**
Change in Rate due to change in under/over recovery			**$ 0.0837**	
C&I LOW WINTER USE COST OF GAS RATE - 01/01/2017		**COGsl**	**$ 0.7419**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1264)**	
C&I LOW WINTER USE COST OF GAS RATE - 2/01/2017		**COGsl**	**$ 0.6155**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1171)**	
C&I LOW WINTER USE COST OF GAS RATE - 3/01/2017		**COGsl**	**$ 0.4984**	**/therm**
Average Demand Cost of Gas Rate Effective 11/01/16	$ 0.0942			
Times: Low Winter Use Ratio (Winter)	1.1637	Maximum (COG + 25%)	$ 0.9131	
Times: Correction Factor	0.9898			
Adjusted Demand Cost of Gas Rate	$ 0.1085			
Commodity Cost of Gas Rate	$ 0.6155			
Adjustment Cost of Gas Rate	$ (0.0457)			
Indirect Cost of Gas Rate	$ 0.0522			
Adjusted C&I Low Winter Use Cost of Gas Rate	$ 0.7305			
C&I HIGH WINTER USE COST OF GAS RATE - 11/01/16		**COGwh**	**$ 0.7121**	**/therm**
Change in rate due to change in under/over recovery			**$ (0.0723)**	
C&I HIGH WINTER USE COST OF GAS RATE - 12/01/2016		**COGsh**	**$ 0.6398**	**/therm**
Change in Rate due to change in under/over recovery			**$ 0.0837**	
C&I HIGH WINTER USE COST OF GAS RATE - 01/01/2017		**COGwh**	**$ 0.7235**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1264)**	
C&I HIGH WINTER USE COST OF GAS RATE - 2/01/2017		**COGwh**	**$ 0.5971**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1171)**	
C&I HIGH WINTER USE COST OF GAS RATE - 3/01/2017		**COGwh**	**$ 0.4800**	**/therm**
Average Demand Cost of Gas Rate Effective 11/01/16	$ 0.0942			
Times: High Winter Use Ratio (Winter)	0.9667	Maximum (COG + 25%)	$ 0.8901	
Times: Correction Factor	0.9898			
Adjusted Demand Cost of Gas Rate	$ 0.0901			
Commodity Cost of Gas Rate	$ 0.6155			
Adjustment Cost of Gas Rate	$ (0.0457)			
Indirect Cost of Gas Rate	$ 0.0522			
Adjusted C&I High Winter Use Cost of Gas Rate	$ 0.7121			

27 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE

II. RATE SCHEDULES			
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE			
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017			
(Refer to Text in Section 17(A) Fixed Price Option Program)			
(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$ 59,710,049		
Projected Prorated Sales (11/01/16 - 04/30/17)	89,920,078		
Direct Cost of Gas Rate		$ 0.6640	per therm
Demand Cost of Gas Rate	$ 8,469,558	$ 0.0942	per therm
Commodity Cost of Gas Rate	55,346,541	$ 0.6155	per therm
Adjustment Cost of Gas Rate	(4,106,050)	$ (0.0457)	per therm
Total Direct Cost of Gas Rate	$ 59,710,049	$ 0.6640	per therm
Total Anticipated Indirect Cost of Gas	$ 4,696,563		
Projected Prorated Sales (11/01/16 - 04/30/17)	89,920,078		
Indirect Cost of Gas		$ 0.0522	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/16) as updated, see page 77		**$ 0.7162**	
Calculation of FPO - Consistent with Order No. 24,515 in DG 05-127			
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/16) as originally filed 9-1-16		**$ 0.7068**	
FPO Risk Premium		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE (11/01/16)		**$ 0.7268**	
RESIDENTIAL COST OF GAS RATE - 11/01/16	**COGwr**	**$ 0.7268**	**/therm**

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28 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE – KEENE DIVISION

Period Covered:	Winter Period November 1, 2014, through April 30, 2015		
Projected Gas Sales - therms			1,076,725
Total Anticipated Cost of Propane Sendout			$1,826,090
Add:	Prior Period Deficiency Uncollected	$9,404	
	Interest	$2,382	
Deduct:	Prior Period Excess Collected	$0	
	Interest	$0	
	Prior Period Adjustments and Interest		$11,786
Total Anticipated Cost			$1,837,876
Cost of Gas Rate			
Non-Fixed Price Option Cost of Gas Rate (per therm)			$1.7069
Fixed Price Option Premium			$0.0200
Fixed Price Option Cost of Gas Rate (per therm)			$1.7269
Non-Fixed Price Option Cost of Gas Rate - Beginning Period (per therm)			$1.7069
Mid Period Adjustment - December 1, 2014			($0.2427)
Mid Period Adjustment - January 1, 2015			($0.0718)
Revised Non-Fixed Price Option Cost of Gas Rate - Effective January 1, 2015 (per therm)			$1.3924
Pursuant to tariff section 17(d), the Company may adjust the approved cost of gas rate upward on a monthly basis to the following rate:			
Maximum Cost of Gas Rate - Non-Fixed Price Option (per therm)			$2.1336

29 CALCULATION OF FIRM TRANSPORTATION COST OF GAS RATE

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	(Col 2)		(Col 3)		(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:					
PROPANE	$ 283,609				
LNG	1,513,890				
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	1,797,499				
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	9.9%				
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	$ 177,952				
PROJECTED FIRM THROUGHPUT (THERMS):					
FIRM SALES	90,536,024		64.4%		
FIRM TRANSPORTATION SUBJECT TO FTCG	50,086,696		35.6%		
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	140,622,721		100.0%		
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	35.6%	x	$ 177,952	=	$ 63,383
PRIOR (OVER) OR UNDER COLLECTION					(33,912)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS					$ 29,471
PROJECTED FIRM TRANSPORTATION THROUGHPUT					50,086,696
FIRM TRANSPORTATION COST OF GAS					$0.0006

30 ENVIRONMENTAL SURCHARGE – MANUFACTURED GAS PLANTS

	Environmental Surcharge - Manufactured Gas Plants		
Manufactured Gas Plants			
Required annual Environmental increase	$2,893,504		
DG 10-17 Base Rate Revision Collections	$0		
Environmental Subtotal	$2,893,504		
Overall Annual Net Increase to Rates	$2,893,504		
Estimated weather normalized firm therms billed for the twelve months ended 10/31/17 - sales and transportation	186,909,214	therms	
Surcharge per therm	$0.0155	per therm	
Total Environmental Surcharge	$0.0155		

31 RATE CASE EXPENSE FACTOR CALCULATION

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities		
Local Distribution Adjustment Charge (LDAC) decrease due to Rate Case Expense and Recoupment		
For LDAC effective November 1, 2016 - December 31, 2016		
Docket No. DG 14-180		
1	August 1, 2016 Balance of Acct. 8840-2-0000-10-1930-1745	$46,132
2	Estimated August 2016 - October 2016 Recovery	($292,028)
3	Estimated August 2016 - October 2016 Interest	($761)
4		
5	Estimated Balance November 1, 2016	($246,658)
6	Estimated November 2016 - December 2016 Interest	($791)
7		
8	Estimated Remaining Recovery	($247,449)
9		
10	Estimated November 2016 - December 2016 Sales (therms)	34,894,997
11		
12	RCE rate per therm November 2016 - December 2016	($0.0071)

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32 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION

Local Delivery Adjustment Clause Calculation

		Sales Customers	Transportation Customers	
Residential Non Heating Rates - R-1, R-5				
Energy Efficiency Charge	$0.0402			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0402		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0016		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0067		
LDAC		**$0.0640**		**per therm**
Residential Heating Rates - R-3, R-4, R-6, R-7				
Energy Efficiency Charge	$0.0402			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0402		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0016		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0067		
LDAC		**$0.0640**		**per therm**
Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**
Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57,G-58				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**

III. DELIVERY TERMS AND CONDITIONS

1 RATES AND CHARGES

1.1 The Company shall apply this tariff on a non-discriminatory and non-preferential basis to all Customers who obtain service from the Company, except as this tariff is explicitly modified by order of the NHPUC. The provisions of Part III Section 20 of this tariff will specifically apply to all entities designated by the Customer as set forth in Section 20.5 to supply Gas to a Designated Receipt Point for the Customer's account.

1.2 The Company reserves the right to impose reasonable fees and charges pursuant to the various provisions of this tariff.

1.3 In the event that the Company incurs minimum bill, inventory, transition, take or pay, imbalance, or any other charges associated with the provision of Delivery Service to Customers, the Company may impose an additional charge on the Suppliers serving said Customers as approved by the NHPUC.

2 DEFINITIONS

Adjusted Target Volume ("ATV)	The volume of Gas determined by the Company using a Consumption Algorithm and required to be nominated and delivered each Gas Day by the Supplier on behalf of Customers taking non-daily metered Delivery Service.
Aggregation Pool	One or more Customer accounts whose Gas Usage is served by the same Supplier and aggregated pursuant to Section 20.6 of this tariff for operational purposes, including but not limited to nominating, scheduling, and balancing Gas deliveries to Designated Receipt Point(s) within the associated Gas Service Area.
Annual Reassignment Date	Five (5) Business Days prior to November 1 of each year when the Company reassigns Capacity to Suppliers pursuant to Section 11.6 of this tariff.
Assignment Date	Five (5) Business Days prior to the first Gas Day of each month when the Company assigns Capacity to Suppliers pursuant to Section 11.4 of this tariff.
Authorization Number	A number unique to the Customer generated by the Company and printed on the Customer's bill that the Customer must furnish to the Supplier to enable the Supplier to obtain the Customer's Gas Usage information pursuant to Section 20.4, and to initiate or terminate Supplier Service as set forth in Section 20.5 of this tariff.
Btu	One British thermal unit; i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit.
Business Day	Monday through Friday excluding holidays recognized by the Company. Where relevant, a Business Day shall consist of the hours during which the Company is open for business with the public. ***If any performance date referenced in this Tariff is not a Business Day, such performance shall be the next succeeding Business Day***.
Capacity	Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity as defined in this tariff.

Capacity Allocators	The estimated proportions of the Customer's Total Capacity Quantity that comprise Pipeline Capacity, Storage Withdrawal Capacity and Peaking Capacity.
Capacity Mitigation Service	The service available to Suppliers in accordance with Section 11.10.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Commodity	See Gas.
Company	Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Company Gas Allowance	The difference between the sum of all amounts of Gas received into the Company's distribution system (including Gas produced by the Company) and the sum of all amounts of Gas delivered from the Company's distribution system divided by said amount of Gas received. Such difference shall include but not be limited to Gas consumed by the Company for its own purposes, line losses, and Gas vented and lost as a result of force majeure, excluding Gas otherwise accounted for.
Company-Managed Supplies	Capacity and Supply contracts held and managed by the Company and made available to the Supplier pursuant to Section 11.9 of this tariff including Supply-sharing contracts and load-management contracts.
Consumption Algorithm	A mathematical formula used to estimate a Customer's daily consumption.
Critical Day	In accordance with Section 16 of this tariff, a day declared at any time by the Company in its reasonable discretion when unusual operating conditions may jeopardize operation of the Company's distribution system.
Customer	The recipient of Delivery Service whose Gas Usage is recorded by a meter or group of meters at a specific location and who is a customer of record of the Company.
Daily Baseload	The Customer's average usage per Gas Day that is assumed to be unrelated to weather.
Daily Index	The mid-point of the range of prices as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)". In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of Gas as the basis for this calculation until such time that the NHPUC approves a suitable replacement.
Dekatherm	Ten Therms.
Delivery Point	The interconnection between the Company's facilities and the Customer's facilities.
Delivery Service	The distribution of Gas by the Company on any Gas Day from the Designated Receipt Point to the Customer's Delivery Point and related Customer services.
Design Peak Season	The forecasted Peak Season during which the Company's system experiences the highest aggregate Gas Usage.

Designated Receipt Point — For each Customer, the Company designated interconnection between a Transporting Pipeline and the Company's distribution facilities at which point, or such other point as the Company may designate from time to time for operational purposes, the Supplier will make deliveries of Gas for the Customer's account.

Designated Representative — The designated representative of the Customer, who shall be authorized to act for, and conclusively bind, the Customer regarding Delivery Service in accordance with the provisions of Section 21 of this tariff.

Gas — Natural Gas that is received by the Company from a Transporting Pipeline at the Designated Receipt Point and delivered by the Company to the Delivery Point for the Customer's account. In addition, the term shall include amounts of vaporized liquefied natural Gas and/or propane-air vapor that are introduced by the Company into its system and made available to the Customer as the equivalent of natural Gas that the Customer is otherwise entitled to have delivered by the Company.

Gas Day — A period of twenty-four (24) consecutive hours beginning at 10:00 a.m., E.T., and ending at 10:00 a.m., E.T., the next calendar day, or other such hours used by the Transporting Pipeline.

Gas Service Area — An area within the Company's distribution system as defined in Section 4 of this tariff, for the purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools.

Gas Usage — The actual quantity of Gas used by the Customer as measured by the Company's metering equipment at the Delivery Point.

Heating Degree Day — A measure used to estimate weather-sensitive Gas consumption calculated by subtracting the average temperature for each day from the number 65. Each degree day that represents a degree below 65 is considered a Heating Degree Day.

Heating Factor — The Customer's estimated weather-sensitive Gas consumption per Heating Degree Day.

MMBtu — One million Btus.

Maximum Daily Peaking Quantity ("MDPQ") — The portion of a Customer's Total Capacity Quantity identified and allocated as Peaking Capacity, such that the maximum daily amount of Gas that can be withdrawn from a Supplier's Peaking Service Account pursuant to Section 14 of this tariff shall be equal to the sum of the MDPQs for all Customers in that Supplier's Aggregation Pool.

Month — A calendar month of Gas Days.

Monthly Index — The average of the Daily Index numbers for all Gas Days in a Month.

NHPUC — The New Hampshire Public Utilities Commission.

Nomination — The notice given by the Supplier to the Company that specifies, in accordance with the Standard Nomination Form attached as Attachment A, an intent to deliver a quantity of Gas to the Designated Receipt Point(s) on behalf of one or more Customers, including the volume to be received, the Designated

	Receipt Point(s), the Transporting Pipeline, the delivering contract(s), the shipper, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months of May to October, inclusive.
Operational Flow Order (“OFO”)	The Company’s instructions to the Supplier to take such action as conditions require including, but not limited to, diverting Gas to or from the Company’s distribution system pursuant to Section 16 of this tariff.
Peak Day	The forecasted Gas Day during which the Company’s system experiences the highest aggregate Gas Usage.
Peak Season	The consecutive months of November to April, inclusive.
Peaking Capacity	Capacity in addition to upstream pipeline and underground storage Capacity normally used by the Company to meet daily requirements during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Service	A Company-managed resource consisting of Peaking Capacity and Peaking Supply.
Peaking Service Account	An account whose balance indicates the total volumes of Peaking Service resources available to a Supplier, where the maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to this tariff.
Peaking Service Rule Curve	A system of operational parameters associated with the use of the Company’s Peaking Capacity including, but not limited to, indicators of the necessary levels of Peaking Supply that must be maintained in Suppliers’ Peaking Service Accounts in order for the Company to meet system demands under Design Peak Season conditions. The Company will communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Peaking Service Rule Curve as identified in Section 14 of this tariff.
Peaking Supply	The aggregate amount of Supply in excess of upstream pipeline and underground storage Supply required to meet the Company's forecasted Supply needs during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Supply Allocator	An allocation factor that represents the proportion of a Customer’s estimated Gas Usage during the Design Peak Season that is generally served with Peaking Service supplies.
Pipeline Capacity	Transportation capacity on interstate pipeline systems normally used for deliveries of Gas to the Company’s city gates, exclusive of Storage Withdrawal Capacity.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the method allocation of discrepancies in confirmed Nominations among the Supplier’s Aggregation Pools and/or Customers as set forth in the Supplier Service Agreement.
Rate Schedule	The schedule of rates included in this tariff.
Reference Period	A period of at least twelve (12) months for which a Customer’s Gas Usage information is typically available to the Company.

Sales Service	Commodity service provided on a firm basis to a Customer who is not receiving Supplier Service, in accordance with the provisions set forth in this tariff. The provision of Sales Service shall be the responsibility of the Company and shall be provided to the Customer by the Company or its designated Supplier pursuant to law or regulation.
Seasonal Storage Capacity	Contracts for Capacity in off-system storage facilities used to accumulate and maintain Gas inventories for re-delivery to the Company's city gates normally during the Peak Season.
Storage Withdrawal Capacity	Capacity for the withdrawal of Gas inventories maintained in off-system storage facilities, as well as the Pipeline Capacity used to deliver such Gas to the Company's city gates.
Supplier	Any entity that has met the Company's requirements set forth in Section 20 of this tariff and that has been designated by a Customer to supply Gas to a Designated Receipt Point for the Customer's account; provided, however, that a Customer may act as its own Supplier in accordance with Section 5.2 of this tariff.
Supplier Service	The sale of Gas to a Customer by a Supplier.
Supplier Service Agreement	An agreement, substantially in the form set forth in Attachment A, which must be executed by the Company and a Supplier in order for the Supplier to serve Customers on the Company's system.
Supply	See Gas.
Therm	An amount of Gas having a thermal content of 100,000 Btus.
Total Capacity Quantity	The total amount of Capacity assignable to a Supplier on behalf
("TCQ")	of a Customer.
Transporting Pipeline	The interstate pipeline company that transports and delivers Gas to the Designated Receipt Point.

3 CHARACTER OF SERVICE

3.1 All rates within Part II Rate Schedule are predicated upon service to a Customer at a single Delivery Point and metering installation, except as otherwise specifically provided by a given rate. Where service is supplied to a Customer at more than one Delivery Point or metering installation, each single Delivery Point or metering installation shall be considered to be a separate Customer for purposes of applying the Rate Schedule, except when a Customer is served through multiple points of delivery or metering installations for the Company's own convenience.

3.2 The Company may refuse to supply service to loads of unusual characteristics which, in its sole reasonable judgment, might adversely affect the quality of service supplied to other Customers, the public safety or the safety of the Company's personnel. In lieu of such refusal, the Company may require a Customer to install any necessary regulating and protective equipment in accordance with the requirements and specifications of the Company.

4 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS

4.1 There shall be 1 Gas Service Area defined for purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools pursuant to this tariff. Each such Gas Service Area shall be defined to include the municipalities listed within each such Gas Service Area, as follows:

(1) Area 1: Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities.
The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelahm, Pembroke, Sanbornton, Tilton, Windham, and part of Canterbury.

4.2 For each Aggregation Pool as set forth by Section 20.6, the Company will designate at least one specific interconnection between a Transporting Pipeline and the Company's distribution facilities, at which point, or such other point as the Company may designate from time to time, the Supplier will make deliveries for the Aggregation Pool. The interconnections that the Company may assign as the Customer's Designated Receipt Point for the Aggregation Pool are as follows:

(1) *Name Transporting Pipeline: Tennessee Gas Pipeline*
Names of City Gates/Meter Numbers:

Nashua/Milford	#020132
Manchester	#020133
Hooksett	#020254
Concord/Laconia	#020426
Suncook	#020451
Londonderry	#020632

(2) *Name Transporting Pipeline: Portland Natural Gas Transmission System*
Names of City Gates/Meter Number

Berlin	#020260

5 CUSTOMER REQUEST FOR SERVICE FROM COMPANY

5.1 Application for Delivery Service, Sales Service, or any other service offered by the Company to a Customer will be received by any duly authorized representative or agent of the Company.

5.2 Before any service from the Company may commence, the Customer must request such service. -A Customer applying for Delivery Service only must also arrange for Supplier Service with a Supplier pursuant to Section 20. A Customer may act as its own Supplier provided it meets all of the Supplier requirements delineated in Section 20.

6 QUALITY AND CONDITION OF GAS

6.1 Gas delivered to the Company by or for the Customer shall conform, in all respects, to the Gas quality standards of the Transporting Pipeline. All Gas tendered by a Supplier at a Designated Receipt Point shall be of merchantable quality and shall be interchangeable with Gas purchased by the Company from its Suppliers. The Company reserves the right to refuse non-conforming Gas.

6.2 In no event shall the Company be obligated to accept and deliver any Gas that does not meet the quality standards of the Transporting Pipeline.

6.3 The Company reserves the right to commingle Gas tendered by a Supplier at a Designated Receipt Point with other Gas, including liquefied natural Gas and propane-air vapor.

6.4 Gas tendered by a Supplier at a Designated Receipt Point will be at a pressure sufficient to enter the Company's distribution system without requiring the Company to adjust its normal operating pressures to receive the Gas. The Company has no obligation to receive Gas at a pressure that exceeds the maximum allowable operating pressure of the Company's distribution system at the Designated Receipt Point.

7 POSSESSION OF GAS

7.1 Gas shall be deemed to be in the control and possession of the Company after such Gas is delivered to the Designated Receipt Point and until the Gas is delivered to the Customer at the Delivery Point. The Company shall not be responsible for the Gas when the Gas is not in the Company's control and possession.

7.2 The Company shall not be liable to the Supplier or the Customer for any loss arising from or out of Delivery Service, including loss of Gas in the possession of the Company or for any other cause, except for the negligence of the Company's own employees or agents.

8 COMPANY GAS ALLOWANCE

8.1 The amount of Gas tendered by the Supplier to the Designated Receipt Point will be reduced, upon delivery to the Customer's Delivery Point, by the Company Gas Allowance. The Company Gas Allowance shall be in effect from November 1 through October 31. Such adjustment shall be recalculated prior to the Company's Peak Season cost of Gas filing with the NHPUC.

9 DAILY METERED DELIVERY SERVICE

9.1 Applicability

Section 9 of this tariff shall be applicable in the following conditions:

9.1.1 All Customers whose service may be interrupted at any time during the year shall be required to take daily metered Delivery Service.

9.1.2 Any Customer, regardless of annual Gas Usage, may elect daily metered Delivery Service.

9.1.3 Customers under Rate Schedules G-43, G-46, G-53, G-54, G-57, and G-58 wishing to take Delivery Service are required to take Daily Metered Delivery Service. In addition, the Company may require a Customer to take daily metered Delivery Service if the Company determines that the daily Gas Usage characteristics of the Customer cannot be accurately modeled using the Company's Consumption Algorithm or if the volumes reasonably anticipated by the Company to be used by the Customer are of a size that may materially affect the integrity of the Company's distribution system.

9.2 Delivery Service Provided

This service provides delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day. For Customers taking Delivery Service under Rate Schedules ***G-43, G-46, G-53, G-54, G-57, and G-58*** this service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point.

9.3 Nominations and Scheduling of Service

9.3.1 The Supplier is responsible for nominating and delivering to the Designated Receipt Point(s) every Gas Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool plus the Company Gas Allowance in accordance with Section 8 of this tariff.

9.3.2 Nominations shall be communicated to the Company by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means.

9.3.3 Nominations for the first Gas Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month Nominations of the Transporting Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of Nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.4 The Supplier may make daily Nominations including, but not limited to, changes to existing Nominations, within a given Month no later than two (2) hours prior to the deadline for daily Nominations of the Transporting Pipeline for the Gas Day on which the Nomination is to be effective, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.5 The Supplier may make intra-Gas Day Nominations, including but not limited to changes to existing Nominations, within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis.

9.3.7 Nominations may be rejected, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Delivery Service in effect from time to time.

9.4 Determination of Receipts

9.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

9.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

9.5 Metering and Determination of Deliveries

9.5.1 The Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. Telemetering equipment shall remain the property of the Company at all times. The Company shall require each Customer to install and maintain, at the Customer's expense, reliable telephone lines and electrical connections that meet the Company's operating requirements. The Company may require the Customer to furnish a dedicated telephone line. If the Customer fails to maintain such telephone lines and electrical connections for fourteen (14) consecutive days after notification by the Company, the Company may discontinue service to the Customer.

9.5.2 Should a Customer or a Supplier request that additional telemetering equipment or a communication device be attached to the existing telemetering equipment in addition to that provided pursuant to Section 9.5.1, the Company shall install, test, and maintain the requested telemetering equipment or communication device; provided that such telemetering equipment or communication device does not interfere with the operation of the equipment required for the Company's purposes and otherwise meet the Company's requirements. The Customer or Supplier shall provide such telemetering equipment or communication device, unless the Company elects to do so. The Customer or Supplier shall bear the cost of providing and installing the telemetering equipment, communication device, or any other related equipment, and shall have electronic access to the Customer's Gas Usage information. Upon installation, the telemetering equipment or communication device shall become the property of the Company and will be maintained by the Company. The Company shall bill the Customer or Supplier after installation.

9.5.3 The Company shall complete installation of telemetering equipment and communication devices, if reasonably possible, within sixty (60) days of receiving a written request from the Customer or Supplier provided that the Customer completes the installation of any required telephone or electrical connections within ten (10) days of such request.

9.5.4 The Company may, at its sole discretion, bill the Customer on a calendar month or cycle month basis.

9.6 Balancing

9.6.1 The Supplier must maintain a balance between daily receipts and daily Gas Usage within the following tolerances:

Off-Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 15% of said receipts. The Supplier shall be charged 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 10% of said receipts. The Supplier shall be charged 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 102% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool exceeds 20% of said receipts [(Receipts - Usage) > (20% x Receipts)].

Critical Day That Will Be Aggravated by Over-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 120% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 5 times the Daily Index to the extent that the difference between the Supplier's actual receipts on the Transporting Pipeline to each Gas Service Area and the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 2% of said receipts [(Receipts - Usage > (2% x Receipts)].

Point Specific Balancing: In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

9.6.2 If the Supplier has an accumulated imbalance within a Month, the Supplier may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

9.6.3 In addition to the charges set forth in Section 9.6.1, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

9.6.4 If, as a result of the Company interrupting or curtailing service pursuant to Section 17 of this tariff, the Supplier incurs a daily imbalance penalty due to over delivery, the Company will waive such penalty for the First Day of the interruption or curtailment period. If the Company has issued notice of an interruption or curtailment in service and the Supplier is unable to change its Nomination, or if the Supplier's Gas has been delivered to the Designated Receipt Point, then the Company will credit such Gas against the Supplier's imbalance.

9.6.5 The Supplier will maintain a balance between receipts at the Designated Receipt Point(s) and the aggregated Gas Usage of Customers in each Aggregation Pool. If the Transporting

Pipeline posts notice on its electronic bulletin board that its customers will be required to adhere to a maximum hourly flow rate, the Supplier will be deemed to have notice that maximum hourly flows will be in effect on the Company's distribution facilities as of the same time and for the same period as maximum hourly flows are in effect on the Transporting Pipeline. The Supplier's maximum hourly flow will be established based on an allocation of even hourly flows of daily receipts of Gas scheduled in the relevant period in accordance with the applicable transportation tariff of the Transporting Pipeline. All Gas Usage in excess of the Supplier's maximum hourly flow rate shall be subject to an additional charge of 5 times the Daily Index for each Dekatherm in excess of the Supplier's maximum hourly flow. The Company will notify the Supplier of the Supplier's maximum hourly flow.

9.6.6 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the aggregated Gas Usage of Customers in the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, and storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

9.7 Cash Out

For each Aggregation Pool, the Supplier must maintain total Monthly receipts within a reasonable tolerance of total Monthly Gas Usage. Any differences between total Monthly receipts for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a percentage of total Monthly receipts, will be cashed out according to the following schedule:

Imbalance Tier	**Over-deliveries**	**Under-deliveries**
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month
> 5% ≤ 10%	0.85 times the above stated rate.	1.15 times the above stated rate.
> 10% ≤ 15%	0.60 times the above stated rate.	1.4 times the above stated rate.
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% under-delivery on a Transporting Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven (7) consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven (7) consecutive Daily Indices.

10 NON-DAILY METERED DELIVERY SERVICE

10.1 Applicability

Section 10 of this tariff applies to Customers taking Delivery Service under Rate Schedules G-41, G-42, G-51, G-52 and their Suppliers.

10.2 Delivery Service Provided

This service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day for Customers, without the requirement of recording Gas Usage at the Delivery Point on a daily basis. Daily Nominations are calculated by the Company on the basis of a Consumption Algorithm and the Supplier is obligated to deliver to the Designated Receipt Point(s) such quantities.

10.3 Nominations and Scheduling of Service

10.3.1 The Supplier is obligated to nominate and deliver the Adjusted Target Volume ("ATV"), as determined in Section 10.3.2, to the Designated Receipt Points on every Gas Day for each Aggregation Pool.

10.3.2 The Company shall determine the ATV for each Aggregation Pool of Customers taking non-daily metered Delivery Service for each Gas Day using a Consumption Algorithm. The ATV shall include the Company Gas Allowance. On each Business Day, the Company will communicate, electronically, by facsimile, or by other agreeable alternative means, the forecasted ATV to the Supplier for at least the subsequent four (4) Gas Days. The ATV in effect for any Gas Day shall be the most recent ATV for that Gas Day communicated to the Supplier by the Company. The ATV for a given Gas Day shall not be effective unless it has been communicated to the Supplier at least two (2) hours prior to the Company's Supplier Nomination deadline for that Gas Day, which shall be at least two (2) hours prior to the deadline for nominations on the Transporting Pipeline, or such lesser period as determined by the Company.

10.3.3 Nominations will be communicated to the Company electronically, by facsimile, or other agreeable alternative means.

10.3.4 Nominations for the first Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month nominations of the Delivering Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.5 The Supplier shall provide an intra-Month nomination no later than two (2) hours prior to the deadline of the Delivering Pipeline for the next Gas Day, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis. The Company will not confirm any volume nominated by the Supplier in excess of the ATV.

10.3.7 In the event that the Supplier is unable to deliver a confirmed ATV Nomination, the Supplier may make intra-Gas Day Nominations relating to changes to existing Nominations within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company; provided, however, that the Nomination must be in conformance with the requirements of and must be permitted by the Transporting Pipeline. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized by the Company for its own operations. The Company shall not adjust the ATV applied for the Gas Day.

10.3.8 Nominations may be rejected if they do not satisfy the conditions for Delivery Service in effect from time to time.

10.3.9 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an Operational Flow Order ("OFO") declared by the Company pursuant to Section 16 will be subject to the Critical Day provisions of Section 10.6.1 of this tariff, and the delivered quantity specified in the OFO will replace the ATV.

10.4 Determination of Receipts

10.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

10.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

10.5 Metering and the Determination of Deliveries

The Company shall record the Customer's Gas Usage at the Delivery Point by making actual meter reads on a monthly [or bi-monthly] basis. In the event that the Customer's Gas Usage is metered on a bi-monthly basis, the Company shall make available to the Supplier estimates of the Customer's Gas Usage for each of the two billing months.

10.6 Balancing

10.6.1 Any difference between the Supplier's ATV for an Aggregation Pool and the receipts on the Transporting Pipeline to the appropriate Designated Receipt Point(s) will be cashed out by the Company according to the following:

Off-Peak Season: For receipts less than the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Peak Season: For receipts less than the ATV but greater than or equal to 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts less than 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the first 5% difference, and the Supplier shall be charged two (2) times the Daily Index for the remaining difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day(s) The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged five (5) times the Daily Index for the difference between the ATV and actual receipts.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged the following amounts for all receipts in excess of the ATV:

(a) up to 25% in excess of the ATV, the Supplier shall be charged the Daily Index for the difference.

(b) for receipts in excess of 25% above the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day That Will Be Aggravated By Over-delivery.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.4 times the Daily Index for receipts greater than the ATV.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged the following amounts--for receipts less than the ATV but greater than or equal to 75% of the ATV, the Supplier shall be charged the Daily Index for the first 25% difference, and the Supplier shall be charged 1.1 times the Daily Index for the remaining difference.

10.6.2 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

10.6.3 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

10.6.4 In addition to the charges set forth in Sections 10.6.1 and 10.6.2, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

10.7 Cash Out

10.7.1 The Company shall use a daily cash out calculation to account for imbalances due to differences in forecast versus actual Heating Degree Days. Using a Consumption Algorithm, the Company will recalculate the ATV for each Aggregation Pool for each Gas Day of the Month, substituting actual Heating Degree Days for forecast Heating Degree Days. Daily recalculations shall be compared to the Aggregation Pool's daily ATV, and the difference shall be cashed out at 100% of the Daily Index.

10.7.2 During the billing months of both June and December, the Company shall use a six-month cash-out calculation to account for differences in forecast usage versus billed Gas Usage. The Company may cash-out differences in forecast usage versus billed usage at intervals that are less than six months as provided by the Supplier Service Agreement.

(1) In the billing month of June, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of November 1 through April 30 to the sum of billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index weighted by actual Heating Degree Days over the same period. The Winter period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending April 30.

(2) In the billing month of December, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of May 1 through October 31 to the sum of the billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index over the same period. The Off-Peak period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending October 31.

10.7.3 The Company shall allow Suppliers to trade seasonal differences. Prior to the seasonal cash-out, the Company shall make available a list of Suppliers. Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company. All trades must be communicated to the Company within three (3) Business Days following receipt of the list.

10.7.4 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the ATVs of the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the Supplier's estimated maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

11 CAPACITY ASSIGNMENT

11.1 Applicability

Section 11 of this tariff applies to all Suppliers that have enrolled one or more Customers into one or more Aggregation Pools and shall include Customers acting as their own Supplier. The Company shall assign and the Supplier shall accept each Customer's pro-rata share of Capacity, if any, as established in accordance with this Section.

11.2 Identification of Capacity for Assignment

11.2.1 On or before September 15 of each year, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Capacity to be made available for assignment to Suppliers on each of twelve Assignment Dates beginning in October.

11.2.2 The Company shall identify, by Gas Service Area, the specific contracts and resources for assignment to Suppliers based on the Company's Capacity and resource plans. Such identified contracts and resources shall be used to determine the pro-rata shares of Capacity assignable to a Supplier on behalf of the Customers enrolled in its Aggregation Pool.

11.2.3 Capacity assigned by the Company may include Company-Managed Supplies that effectuate, at maximum tariff rates, the assignment of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)] and other contracts that are not assignable to third-parties due to governing tariffs.

11.3 Determination of Pro-Rata Shares of Capacity

11.3.1 The Company shall establish a Total Capacity Quantity ("TCQ") for each Customer taking Delivery Service. The TCQ represents the total amount of Capacity assignable to a Supplier on behalf of a Customer.

11.3.2 For a Customer receiving Sales Service on or after March 14, 2000, the TCQ shall be the Customer's estimated Gas Usage on the Peak Day as determined by the Company each October prior to the Customer's enrollment into Supplier Service. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during the Reference Period, or the best estimates available to the Company should actual Gas Usage information be partially or wholly unavailable.

11.3.3 For a Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had an executed contract for firm transportation service (i.e., the equivalent of Delivery Service) on file with the Company on or before March 14, 2000, the TCQ shall be zero.

11.3.4 A Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had a written request on file with the Company on or before March 14, 2000 may elect for its Supplier to accept assignment of its pro-rata share of Capacity as determined by the Company in accordance with Section 11.2 and, subject to availability, as determined by the Company in its sole reasonable discretion. In order to make such election, the Customer must have submitted to the Company, on or before ten (10) days prior to the first Assignment Date prior to the original effective date of this tariff, a completed application for Capacity that is signed by both the Customer and Supplier. All assignments of Capacity made on behalf of such electing Customer shall be executed in accordance with Sections 11 and 14 of this tariff as if the Customer had been receiving Sales Service on or after March 14, 2000

11.3.5 For a new Customer taking Supplier Service as its initial service after March 14, 2000, the TCQ shall be zero except in cases where the Customer is a new Customer of record at a meter location where a former Customer of record received firm service from the Company any time during the preceding twenty-four (24) months, in which case the TCQ established by the Company for the former Customer shall become the TCQ for the new Customer. The Company may reduce said TCQ value for the new Customer, if, in its sole reasonable discretion, the Company determines that the old Customer's TCQ exceeds the new Customer's estimated future consumption on the Peak Day. In the event that Sales Service is provided at a new meter location for Gas Usage associated with new construction, the TCQ shall be zero, provided that the Customer initiates Supplier Service upon the completion of said new construction in accordance with Section 20.5 of this tariff

11.3.6 Once the Company establishes a TCQ for a Customer pursuant to this Section 11.3, it shall remain in effect for the purpose of determining the Customer's pro-rata shares of Capacity until such time that the Customer returns to Sales Service. The Company shall establish a new TCQ value for the Customer pursuant to Section 11.3.2 if the Customer again elects to take Supplier Service after returning to Sales Service, unless otherwise established herein..

11.3.7 The Company shall determine the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assignable to a Supplier on behalf of a Customer as the product of the Customer's TCQ times the applicable Capacity Allocators. The Capacity Allocators for each class of Customers billed under the Company's Rate Schedule shall be set forth annually in Attachment C to this tariff.

11.3.8 The Company shall determine the pro-rata share of Seasonal Storage Capacity assignable to a Supplier on behalf of a Customer consistent with the tariffs governing the associated Storage Withdrawal Capacity.

11.3.9 The Company shall determine the pro-rata shares of Peaking Supply assignable to a Supplier in accordance with Section 14 of this tariff.

11.4 Capacity Assignments

11.4.1 On each Assignment Date, the Company will assign to the Supplier the pro-rata shares of Capacity on behalf of each Customer as determined by the Company in accordance with Sections 11.2, 11.3 and 11.7.

11.4.2 The total amount of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assigned to the Supplier on behalf of the Customers in an Aggregation Pool shall be at least equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of Five (5) Business Days prior to the Assignment Date.

11.4.3 Storage Withdrawal Capacity shall be subject to Operational Flow Orders that are issued by the Company pursuant to Section 16 of this tariff, in the event that the Company requires the Supplier to deliver or to store quantities of Gas for the purposes of managing system imbalances and maintaining Delivery Service. Whenever the Company assigns incremental Storage Withdrawal Capacity to the Supplier, the Company shall also assign to that Supplier additional Seasonal Storage Capacity pursuant to Section 11.8.

11.4.4 The Peaking Capacity assigned to the Supplier shall establish the Maximum Daily Peaking Quantity (“MDPQ”) for the Aggregation Pool in the Supplier’s Service Agreement. In the event that the Company increases a Supplier’s MDPQ, the Company shall also assign to that Supplier additional Peaking Supply pursuant to Section 14.

11.4.5 The Company shall execute Capacity assignments in increments of 200 MMBtus. The Supplier shall accept an initial increment of Capacity on the first Assignment Date when the sum of the pro-rata shares of Capacity assigned to the Supplier pursuant to Section 11.4.1 exceeds 150 MMBtus. The Supplier shall accept additional increments of Capacity on the following Assignment Dates commensurate with any cumulative increase in the sum of pro-rata shares of Capacity assigned to the Supplier, as rounded to the nearest 200 MMBtus. Each increment of Capacity accepted by the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative increase of the pro-rata shares of assigned Capacity as established in accordance with Section 11.4.1. Section 11.4.2 shall not apply to a Customer that is acting as its own Supplier.

11.4.6 If a Customer is acting as its own Supplier, the Company shall assign Capacity to the Customer in an amount equal to the Customer's TCQ, as established pursuant to Section 11.3.

11.5 Release of Contracts

11.5.1 With the exception of Company-Managed Supplies and Peaking Capacity, Capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or lesser rate paid by the Company and including all surcharges, through pre-arranged Capacity releases, pursuant to applicable laws and regulations and the terms of the governing tariffs.

11.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released for a term beginning on the first Gas Day of the Month following the Assignment Date through the expiration date of the respective capacity contract being assigned. and ending on October 31. For example, contracts assigned to a Supplier on April 25 of a given year shall be released for a term beginning on May 1 of that year and ending on October 31 of that year.

11.5.3 The Company reserves the right to adjust releases of Storage Withdrawal Capacity in the event that fifty percent (50%) or more of the total Storage Withdrawal Capacity serving a Gas Service Area has been assigned to Suppliers. Such adjustments may include, but are not limited to, the reassignment of certain Storage Withdrawal Capacity as Company-Managed Supplies in order for the Company to maintain operational control over Capacity resources associated with system balancing, and/or the retention of specific Capacity resources associated with system balancing and the implementation of a balancing charge to offset the associated costs.

11.6 Annual Reassignment of Capacity

11.6.1 On each Annual Reassignment Date, the Company shall adjust the Capacity assignments previously made to a Supplier to conform with the Company's resource and requirements plans. Such previously assigned Capacity shall be replaced by the assignment to the Supplier of the pro-rata shares of the same or similarly situated Capacity on behalf of the Customers enrolled in the Supplier's Aggregation Pools (as of the first Gas Day of the Month following the Annual Reassignment Date).

11.6.2 If the reassignment of Storage Withdrawal Capacity requires adjustments to the Seasonal Storage Capacity previously assigned to a Supplier, the Company shall reassign Seasonal Storage Capacity to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to inventories in place pursuant to Section 11.8 of this tariff.

11.6.3 If the reassignment of Peaking Capacity requires adjustments to the MDPQ for the Supplier's Aggregation Pool, the Company shall reassign Peaking Supply to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to supplies pursuant to Section 14 of this tariff.

11.7 Recall of Capacity

11.7.1 If the pro-rata shares of Capacity assignable to a Supplier decline because one or more of the Supplier's Customers has returned to Sales Service, the Company shall have the right, but not the obligation, to recall from the Supplier the pro-rata shares of Capacity previously assigned to the Supplier on behalf of such Customers. The decision on whether to exercise its Capacity-recall rights shall be made by the Company in its sole reasonable discretion. If the Company elects to recall Capacity from a Supplier pursuant to this Section, such recall shall be made on the Assignment Date following the effective date of the Customer's return to Sales Service. Notwithstanding the foregoing, in the following circumstances the Company shall be required to recall Capacity associated with Customers returning to Sales Service:

(a) The Supplier returning the Customers to Sales Service certifies that it is ceasing all business operations in New Hampshire;

(b) The Supplier returning the Customers to Sales Service certifies that it will no longer offer service to a particular market sector (e.g., small commercial and industrial Customers) and, therefore, once such Customers are returned to Sales Service, the Supplier is not eligible to re-enroll Customers of that type; or

(c) The Supplier demonstrates that it has provided Supplier Service to the Customer for a 12-month period, and for a period of no less than any 12-month increment, prior to the Customer's return to Sales Service.

11.7.2 If the Company elects to recall Storage Withdrawal Capacity from the Supplier pursuant to this Section, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company elects to reduce the MDPQ in the Supplier Service Agreement, the Company shall reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.3 In the event that a Customer in a Supplier's Aggregation Pool switches to another Supplier, the Company shall recall from the former Supplier said Customer's pro-rata shares of Capacity for reassignment to the new Supplier pursuant to Section 11.4. There shall be no change in the Customer's TCQ used to determine the Customer's pro-rata shares of Capacity for reassignment to the new Supplier. The recall of such Capacity from the Customer's former Supplier and the assignment of Capacity to the new Supplier shall be made on the Assignment Date following the effective date of the Customer's switch in Suppliers.

If the Company recalls Storage Withdrawal Capacity from the Customer's former Supplier, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company reduces the MDPQ in the Customer's former Supplier's Service Agreement, the Company shall also reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.4 The recall of Capacity by the Company shall entail the recall of released contracts pursuant to governing tariffs and/or the reduction in assigned quantities set forth in the Supplier Service Agreement. The recall of Capacity shall be executed in decrements of 200 MMBtus, commensurate with the cumulative reduction in the pro-rata shares of Capacity assigned to the Supplier, rounded to the nearest 200 MMBtus. Each decrement of Capacity assigned to the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative decrease in the pro-rata shares of Capacity recalled from the Supplier.

In the event that a Supplier is declared ineligible to nominate Gas for thirty (30) Gas Days pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such 30 Gas Days, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro-rata shares of Capacity for reassignment.

11.7.5 In the event that a Supplier is disqualified from service for a one (1) full year pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro rata shares of Capacity reassignments.

11.7.6 In the event that the Supplier fails to meet the applicable registration and licensing requirements established by law or regulation, fails to satisfy the requirements and practices as set forth in Section 20.3 of this tariff, fails to be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, fails to make timely payment under the assigned contracts, or fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement, the Company shall have the right to recall permanently any or all Capacity assigned to said Supplier. This section shall also apply to a Customer acting as its own Supplier.

11.7.7 The Supplier shall forfeit its rights to Capacity recalled by the Company pursuant to this Section. Such forfeiture shall be effected in accordance with applicable laws and regulations and the governing tariffs. In the event of Capacity forfeiture pursuant to this Section, the Supplier shall be responsible to compensate the Company for any payments due under the contracts prior to forfeiture, as well as any interest due thereon. The Company will not exercise discretion in the application of the forfeiture provisions of this Section. This section shall also apply to a Customer acting as its own Supplier.

11.8 Seasonal Storage Capacity

11.8.1 On each Assignment Date, the Company shall release Seasonal Storage Capacity to a Supplier that accepts the assignment of Storage Withdrawal Capacity pursuant to Section 11.4. The Company shall assign such Seasonal Storage Capacity consistent with the tariffs governing the release of the associated Storage Withdrawal Capacity.

11.8.2 If the Company assigns Seasonal Storage Capacity to a Supplier pursuant to Section 11.8.1 above, the Company shall transfer in-place Gas inventories to the Supplier. The quantity of inventories to be transferred from the Company to the Supplier shall be determined by multiplying the incremental Seasonal Storage Capacity assigned to the Supplier on the Assignment Date times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be charged the Company's weighted average cost of inventories in off-system storage facilities for each Dekatherm transferred from the Company to the Supplier. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two Business Days prior to each Assignment Date.

11.8.3 In the event that the Company recalls Storage Withdrawal Capacity from the Supplier pursuant to Section 11.7, the Company shall also recall Seasonal Storage Capacity from the Supplier. The Company shall determine the total Seasonal Storage Capacity to be recalled from the Supplier in accordance with the tariffs governing the Storage Withdrawal Capacity returned to the Company.

11.8.4 If the Company recalls Seasonal Storage Capacity from a Supplier pursuant to Section 11.8.3, the Supplier shall transfer in-place Gas inventories to the Company. The quantity of inventories to be transferred from the Supplier to the Company shall be determined by multiplying the decremental Seasonal Storage Capacity times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be reimbursed at the Company's weighted average cost of inventories in off-system storage facilities as of the Assignment Date, for each Dekatherm transferred from the Supplier to the Company. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two (2) Business Days prior to each Assignment Date.

11.8.5 Seasonal storage inventory percentages shall represent the amount of Seasonal Storage Capacity in each assigned storage resource that is assumed to be filled with inventories as of the first Gas Day of the month following the Assignment Date. Each September, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the storage inventory percentages for each resource that shall be applied to incremental or decremental Seasonal Storage Capacity assignments executed on each of the twelve (12) Assignment Dates beginning in October.

11.9 Company-Managed Supplies

11.9.1 The Company shall provide access to and ascribe cost responsibility for the pro-rata shares of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)], and other contracts that are not assignable to third-parties.

11.9.2 The Supplier's Service Agreement shall set forth the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 11.4 and 11.8.

11.9.3 The Company shall notify the Supplier of the conditions and/or restrictions on the use of Company-Managed Supplies pursuant to the tariffs governing the resources.

11.9.4 The Company shall invoice the Supplier for its pro-rata shares of the demand charges for Capacity contracts assigned to the Supplier as Company-Managed Supplies. The Company shall also flow through to the Supplier all costs, including Supply costs, incurred from the utilization of Company-Managed Supplies on behalf of the Supplier.

11.9.5 The Company shall nominate quantities to the Transporting Pipeline and/or other interstate pipelines and off-system storage operators on behalf of Suppliers to which the Company has assigned Company-Managed Supplies, provided that the requested Nomination conforms to the tariffs governing the resource. The Supplier shall communicate its desired Nomination quantities to the Company subject to the provisions in Sections 9.3 and 10.3 of this tariff.

11.10 Capacity Mitigation Service

11.10.1 Capacity Mitigation Service is available to Suppliers that have been assigned Capacity pursuant to Section 11 of this tariff. Such Suppliers shall have the option to take Capacity Mitigation Service from the Company for contracts that would otherwise be released to the Supplier in accordance with this tariff.

11.10.2 Within five (5) Business Days prior to the Annual Reassignment Date, the Supplier must designate those contracts that would otherwise be released to the Supplier pursuant to Section 11.5, as contracts to be managed by the Company for cost mitigation in accordance with the Company's Capacity Mitigation Service. Such designation will be effective for the period November 1 through October 31. Such notice shall be communicated in accordance with the Supplier's Service Agreement.

11.10.3 The Supplier shall pay to the Company the maximum-tariff rate or lesser rate paid by the Company, including all surcharges, for the Capacity contracts that are retained and managed by the Company. The Company shall bill the Supplier monthly for such charges.

11.10.4 The Company will market Capacity contracts designated by Suppliers for mitigation through the Capacity Mitigation Service. The Supplier shall receive a credit on its bill for Capacity Mitigation Service equal to the pro-rata share of the proceeds earned from the Company in exchange for such contract management. Such credit shall be determined on a contract-specific basis at the end of each Month and will be included in the bill sent to the Supplier in the following Month.

12 BILLING AND SECURITY DEPOSITS

12.1 The Customer shall be responsible for all charges for service furnished by the Company under the Company's applicable rates, as filed from time to time with the NHPUC, from the time service is commenced until it is terminated. The Company shall provide a single bill, reflecting unbundled charges, to Customers for Sales Service.

12.2 The Company shall offer two billing service options to Customers taking only Delivery Service: standard complete billing service and standard pass-through billing service. The Supplier shall inform the Company of the selected billing option in accordance with the provisions set forth in Section 20.5

12.2.1 Standard Complete Billing Service

The Customer shall receive a single bill from the Company for both Delivery Service and Supplier Service. The Company shall use the rates supplied by the Supplier to calculate the Supplier's portion of the single bill and integrate this billing within a single mailing to the Customer. The Company may charge a fee to the Supplier for providing this billing service as approved by the NHPUC.

The Supplier shall adhere to the Customer classes and rate structure as specified in the Company's then current Rate Schedule on file with and approved by the NHPUC. The Company shall reasonably accommodate, at the Supplier's expense, different Customer classes or rate structures as agreed to by the Company and the Supplier in the Supplier Service Agreement.

The Company shall provide an electronic file to the Supplier that will, in addition to the usage being billed, contain the calculated Supplier billing amounts for the current billing cycle. Customer revenue due the Supplier shall be transferred to the Supplier in accordance with the Supplier Service Agreement. Upon receipt of Customer payments, the Company shall provide a file for the Supplier summarizing all revenue from Supplier sales which have been received and recorded that day.

If a Customer pays the Company less than the full amount billed, the Company shall apply the payment first to Delivery Service, and if any payment remains, it shall be applied to Supplier Service.

12.2.2 Standard Pass-through Billing Service

The Customer taking Delivery Service shall receive two (2) bills: the Company shall issue one bill for Delivery Service and the Supplier shall issue a second bill for Supplier Service.

The Supplier shall be responsible for the collection of amounts due to the Supplier from the Customer. Customer payment responsibility with Suppliers shall be governed by the particular Customer/Supplier contract.

Within three (3) Business Days following the end of the Customer's billing cycle, the Company shall provide an electronic file for the Supplier that will contain the Customer's usage being billed including the current and previous meter readings.

12.2.3 The Company shall inform a Customer when Supplier Service has been initiated by a Supplier along with information on how the Customer may file a complaint regarding an unauthorized initiation of Service. This information shall be included on the first bill rendered to the Customer after such initiation.

12.2.4 A Customer acting as its own Supplier will be subject to the billing and payment requirements in Section 20.8 of this tariff.

12.2.5 Readings taken by an automated meter reading device will be considered actual readings for billing purposes.

13 SALES SERVICE

13.1 Sales Service is the Commodity service provided by the Company for Customers not electing to subscribe to Supplier Service and shall be provided by the Company, or its designated Supplier, in accordance with this tariff. Each Customer receiving Sales Service shall receive one bill from the Company reflecting delivery and Commodity charges.

13.2 A Customer receiving Sales Service on March 14, 2000 shall continue to receive Sales Service unless the Customer elects to take Supplier Service and until such time that Supplier Service is initiated for the Customer in accordance with Section 20.5 of this tariff. If the Customer terminates Supplier Service, if a Supplier terminates service to the Customer, or if the Customer's designated Supplier becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide Sales Service to the Customer. Pursuant to Section 20.5 of this tariff, the Company will initiate Sales Service for the Customer and will provide Sales Service to the Customer until such time that Supplier Service is initiated for the Customer by a new Supplier.

13.3 Any Customer whose Supplier has been assigned Capacity on behalf of said Customer pursuant to Section 11 of this tariff may elect to return to Sales Service if the Customer is no longer receiving Supplier Service. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until such time that Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to said Customer up to a maximum daily level of Gas Usage not to exceed the Total Capacity Quantity ("TCQ") of recallable Capacity assigned to the Customer's former Supplier.

13.4 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff terminates Supplier Service to the Customer, the Customer may select another Supplier. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to the Customer up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's former Supplier.

13.5 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide the Customer with Sales Service up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's Supplier.

13.6 The Company shall be under no obligation to provide Sales Service to a Customer at a maximum daily level in excess of the TCQ of recallable Capacity assigned to a Supplier on behalf of the Customer. The Company may elect to provide Sales Service to the Customer if, and to the extent that, adequate system Capacity and Supplies are available and upon the same terms and subject to the same conditions as any new Customer seeking to take Sales Service.

14 PEAKING SERVICE

14.1 Applicability

Section 14 of this tariff applies to all Suppliers, and to all Customers acting as their own Supplier, that have been assigned, or have elected to be assigned, Capacity on behalf of themselves or Customers in their Aggregation Pools pursuant to Section 11 of this tariff.

14.2 Character of Service

14.2.1 Peaking Service shall be provided by the Company subject to an executed Supplier Service Agreement that sets forth the Maximum Daily Peaking Quantity (“MDPQ”) and the assigned Peaking Supply for each of the Supplier’s Aggregation Pools.

14.2.2 The Company shall provide quantities of Gas, at the Supplier’s request, from the Supplier’s Peaking Service Account as established in accordance with Section 14.4. Such quantities shall be deemed delivered by the Company and received by the Company at the Designated Receipt Point(s) for the Aggregation Pool. Peaking Service shall be firm and available to the Supplier each Gas Day in accordance with the balance of the Supplier’s Peaking Service Account and the parameters of the Company’s Peaking Service Rule Curve.

14.3 Rates and Charges

14.3.1 The applicable rates for Peaking Service shall be established in the Company’s tariff. The Supplier shall pay a peaking demand charge based on its MDPQ of assigned Peaking Capacity as billed by the Company for the Peak Season. Such unit demand charge shall be equal to the total Capacity costs and other fixed costs associated with the Company’s peaking resources, excluding costs collected through Delivery rates, divided by the estimated peaking resources needed to meet the Company’s total system Peak Day requirement.

14.3.2 The Supplier shall pay a Commodity charge equal to the estimated weighted average cost of peaking supplies, including fuel retention and carrying charges. The Company shall communicate electronically, by facsimile or by other agreeable alternative means the Company’s estimated weighted average cost of peaking supplies by the 15th of the month preceding the next Assignment Date. The Commodity charge will be multiplied by the volumes of Peaking Service Gas nominated by the Supplier during each Month.

14.4 Peaking Supply

14.4.1 The Customer’s portion of the Peaking Supply that shall be assigned to the Supplier on behalf of the Customer shall be equal to the Peaking Supply multiplied by the ratio of the Customer’s MDPQ to the aggregate MDPQ of the total system.

14.4.2 On each Assignment Date, the Company shall assign Peaking Supply to a Supplier whose MDPQ has been increased pursuant to Section 11.4. If the Company assigns incremental Peaking Supply to a Supplier, the Company shall credit the balance of the Supplier’s Peaking Service Account for volumes available through October 31 in accordance with the

Peaking Service Rule Curve. The amount credited to the Supplier's Peaking Service Account shall be determined by multiplying the incremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.3 On each Assignment Date, the Company shall recall Peaking Supply from a Supplier whose MDPQ has been decreased pursuant to Section 11.7. The Company shall determine the Supplier's total Peaking Supply for recall to be equal to the difference between the cumulative total Peaking Supply assigned to the Supplier as of the previous Assignment Date and the total Peaking Supply that is assignable to the Supplier in accordance with Section 14.4.1 above.

14.4.4 If the Company recalls Peaking Supply from a Supplier pursuant to Section 14.4.3, the Company shall debit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount debited from the Supplier's Peaking Service Account shall be determined by multiplying the decremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.5 The peaking inventory percentage shall represent the level of Peaking Supply assumed to be available to a Supplier in its Peaking Service Account as of the first Gas Day of the Month following the Assignment Date for incremental and decremental assignments of Peaking Supply. Each September, the Company shall communicate electronically, by facsimile or by other agreeable alternative means the Peaking Inventory Percentages that shall be applied to incremental or decremental Peaking Supply assignments executed on each of the twelve (12) Assignment Dates beginning in October.

14.4.6 On each Annual Reassignment Date, the Company shall reset the balance in the Supplier's Peaking Service Account to equal the total Peaking Supply assignable to the Supplier on behalf of Customers enrolled in its Aggregation Pool (as of the first Gas Day of the Month following the Annual Reassignment Date) as determined in accordance with Section 14.4.1 above.

14.5 Nomination of Peaking Service

14.5.1 The Supplier shall nominate with the Company the quantity of Peaking Supply, not in excess of the amount determined pursuant to Section 14.4.2, that the Supplier desires to be provided from its Peaking Service Account for the applicable Gas Day. For an Aggregation Pool of Customers taking daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 9.3 of this tariff. For an Aggregation Pool of Customers taking non-daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 10.3 of this tariff.

14.5.2 In response to a valid Nomination for Peaking Service, the Company shall provide the requested quantity of Gas, which shall be deemed to be delivered by the Company and received by the Company at the Designated Receipt Point(s) of the Supplier's Aggregation Pool, subject to the limitations herein. Nominated quantities shall be included in the determination of receipts at the Designated Receipt Point(s) for the Supplier's Aggregation Pool which factors into the daily balancing provisions set forth in this tariff.

14.5.3 The Company may reject a Supplier's Nomination for Peaking Service if the nominated quantity would cause the balance of the Supplier's Peaking Service Account to fall to a level that is 10% or more below the minimum allowable account balance for the Month in which the Nomination is requested, as computed in accordance with the Peaking Service Rule Curve. Under such circumstances, the Company shall require the Supplier to nominate the pipeline and/or storage resources, within the contract entitlements assigned to the Supplier under Section 11, required to maintain the Supplier's Peaking Service Account above the minimum allowable account balance described above. The balance of the Supplier's Peaking Service Account may not in any event fall below zero (0).

14.5.4 The Company shall provide Peaking Service supplies to the Supplier only when the volumes in the Peaking Service Account for the Aggregation Pool are greater than zero (0).

14.6 Peaking Service Critical Day Provisions

14.6.1 In the event that the volumes in a Supplier's Peaking Service Account for an Aggregation Pool are reduced to a level below the minimum allowable account balance as computed in accordance with the Company's Peaking Service Rule Curve, the Company may issue an OFO to such Supplier pursuant to Section 16 of this tariff.

14.6.2 In the event that the total volumes of all Peaking Service Accounts within one or more of the Company's Gas Service Areas are reduced to levels below the total minimum allowable account balances as computed in accordance with the Company's Peaking Service Rule Curve, the Company may declare a Critical Day and issue a blanket OFO pursuant to Section 16 of this tariff.

14.6.3 If, on a Critical Day, the Company projects, based on the Supplier's Nominations, that the Supplier's scheduled deliveries to the Designated Receipt Point(s) of an Aggregation Pool are less than the maximum feasible volumes for deliveries on the Transporting Pipeline, the Company may issue an OFO to the Supplier in accordance with Section 16 of this tariff.

15 DISCONTINUANCE OF SERVICE

15.1 The Company shall notify a Customer's Supplier of record that it has initiated any applicable billing and termination procedures as prescribed by the NHPUC. In the event that the Company discontinues Delivery Service to a Customer in accordance with the provisions set forth above, the Company shall provide electronic notification to the Customer's Supplier of record upon final billing to the Customer. The Company shall not be liable for any revenue loss to the Supplier as a result of any such disconnection.

16 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS

16.1 In the event of a material and significant threat to the operational integrity of the Company's system, the Company may declare a Critical Day.

16.2 Circumstances constituting a threat to the operational integrity of the system that may cause the Company to declare a Critical Day shall include, but not be limited to: (1) a failure of the Company's distribution, storage, or production facilities; (2) near-maximum utilization of the Company's distribution, storage, production, and Supply resources; (3) inability to fulfill firm service obligations; and (4) issuance of an OFO or similar notice by upstream transporters.

16.3 In the event that the Company has declared a Critical Day, the Company will have the right to issue an Operational Flow Order ("OFO") in which the Company may instruct Suppliers to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system, within the contract entitlements, if any, assigned to the Supplier under Section 11 hereof. An OFO may be issued on a pipeline or point-specific basis. An OFO may be issued by the Company as a blanket order to all Suppliers or to an individual Supplier whose actions are determined by the Company to jeopardize system integrity. -The Company may issue an OFO to an individual Supplier if the Company faces Gas cost exposure in excess of daily cashout or imbalance penalties as set forth in Sections 9.6, 9.7, 10.6, and 10.7 for any under-deliveries or over-deliveries caused by that Supplier.

16.4 The Company will provide the Supplier with as much notice as is reasonably practicable of the issuance and removal of a Critical Day or an OFO; under most circumstances, the Company intends to provide at least twenty-two (22) hours' notice prior to the start of the Gas Day for the issuance of the Critical Day or OFO. Notification of the issuance and removal of a Critical Day or an OFO will be made by means as established in the Supplier Service Agreement. The Supplier will be responsible for coordinating with its Customers any change to the Customer's quantity of Gas Usage. An OFO or Critical Day will remain in effect until its removal by the Company.

16.5 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an OFO will be subject to the Critical Day provisions of Sections 9.6 and 10.6 of this tariff.

17 FORCE MAJEURE AND LIMITATION OF LIABILITY

17.1 Neither the Company nor the Supplier will be liable to the other for any act, omission, or circumstance occasioned by or in consequence of any event constituting force majeure, and unless it is otherwise expressly provided herein, the obligations of the Company and the Supplier then existing hereunder will be excused during the period thereof to the extent affected by such event of force majeure, provided that reasonable diligence is exercised to overcome such event. As used herein, force majeure will mean the inability of the Company or the Supplier to fulfill its contractual or regulatory obligations: as a result of compliance by either party with an order, regulation, law, code, or operating standard imposed by a governmental authority; by reason of any act of God or public enemy; by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, or breakage or accident to machinery or pipeline (which breakage or accident is not the result of the negligence or misconduct of the party claiming force majeure); by reason of any declaration of force majeure by upstream Transporting Pipelines; or by reason of any other cause, whether the kind enumerated herein or otherwise, not within the control of the party claiming force majeure and which by the exercise of reasonable diligence such party is unable to prevent or overcome. Notwithstanding the foregoing, the Customer's and the Supplier's obligation to make any payments required under this tariff will in no case be excused by an event of force majeure. Nor will a failure to settle or prevent any labor dispute or other controversy with employees or with anyone purporting or seeking to represent employees be considered to be a matter within the control of the party claiming excuse. The party claiming force majeure will, on request, provide the other party with a written explanation thereof and of the remedy being undertaken.

17.2 The Company shall be liable only for direct damages resulting from the Company's conduct of business when the Company, its employees, or agents have acted in a negligent or intentionally wrongful manner. In no event shall the Company be liable to any party for any indirect, consequential, or special damages, whether arising in tort, contract, or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under this tariff or in accordance with or required by law, including, without limitation, termination of the Customer's service.

17.3 If the Company is unable to render firm Delivery Service to the Customer taking such service as contemplated by this tariff as a result of force majeure and such inability continues for a period of thirty (30) Gas Days, the Customer may provide written notice to the Company of its desire to terminate Delivery Service at the expiration of thirty (30) Gas Days from the Company's receipt of such notice, but no sooner than sixty (60) Gas Days following the outset of the force majeure. If the Company has not restored Delivery Service to the Customer at the end of such notice period, the Customer's Delivery Service will terminate and both parties will be released from further performance hereunder, except for obligations to pay sums due and owing as of the date of termination.

17.4 The Company and the Supplier shall indemnify and hold the other and their respective affiliates, and the directors, officers, employees, and agents of each of them (collectively, "affiliates") harmless from and against any and all damages, costs (including attorney's fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively, "liabilities"), resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of either party in connection with the performance of the indemnifying party's obligations under this tariff. The Company and the Supplier shall waive recourse against the other party and its affiliates for or arising from the non-negligent performance by such other party in connection with the performance of its obligations under this tariff.

18 CURTAILMENT

18.1 Whenever the integrity of the Company's system or the Supply of the Company's Customers taking Sales Service or Delivery Service is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole reasonable judgment, curtail or interrupt Gas service or reduce pressure as set out in Section 18, Supply and Capacity Shortage Allocation Policy of this tariff. Such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect. The Company will use efforts reasonable under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

18.2 The Company shall communicate notice of curtailment as soon as practicable to the Suppliers of affected Customers by means as specified in the Supplier Service Agreement.

18.3 The Company shall take reasonable care in providing regular and uninterrupted service to its firm Customers, but whenever the Company deems that the situation warrants any interruption or limitation in the service to be rendered, such interruption or limitation shall not constitute a breach of the contract and shall not render the Company liable for any damages suffered thereby by any person, or excuse the Customer from further fulfillment of the contract.

18.4 In any case where the Company determines in its judgment that a curtailment or interruption of firm services is necessary, the Company will curtail and/or interrupt firm Delivery Service and Sales Service Customers on a nondiscriminatory basis.

19 TAXES

19.1 In the event a tax of any kind is imposed or removed by any governmental authority on the distribution of Gas or on the gross revenues derived from the distribution of Gas at retail (exclusive, however, of taxes based on the Company's net income), the rate for service herein stated will be adjusted to reflect said tax. Similarly, the effective rate for service hereunder will be adjusted to reflect any refund of imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental or regulatory authorities.

19.2 The Customer will be responsible for all taxes or assessments that may now or hereafter be levied with respect to the Gas or the handling or subsequent disposition thereof after its delivery to the

Delivery Point. However, if the Company is required by law to collect and/or remit such taxes, the Customer will reimburse the Company for all amounts so paid. If the Customer claims exemption from any such taxes, the Customer will provide the Company in writing its tax exemption number and other appropriate documentation. If the Company collected any taxes or assessments from the Customer and is later informed by the Customer that the Customer is exempt from such taxes, it shall be the Customer's responsibility to obtain any refund from the appropriate governmental taxing agency.

19.3 The Supplier will be responsible for all production, severance, ad valorem, or similar taxes levied on the production or transportation of the Gas before its delivery to the Designated Receipt Point. The Supplier will also be responsible for sales taxes imposed on Gas delivered for the Customer's account. However, if the Company is required by law to remit such taxes to the collecting authority, it will do so and invoice the Supplier for such taxes paid on the Supplier's behalf.

20 SUPPLIER TERMS AND CONDITIONS

20.1 Applicability

The following terms and conditions shall apply to every Supplier providing Supplier Service in the State of New Hampshire, to every Customer doing business with said Suppliers, and to Customers acting as their own Supplier.

20.2 Obligations of Parties

20.2.1 Customer

Unless otherwise agreed to by the Company and the Customer, a Customer shall select one Supplier for each account at any given time. A Customer electing Supplier Service must provide the selected Supplier with its applicable Authorization Number. A Customer may choose only a Supplier who meets the terms described in Sections 20.2.3 and 20.3 below and who meets any applicable registration requirements established by law or regulation.

20.2.2 Company

The Company shall deliver Customer purchased Gas from the Designated Receipt Point to the Delivery Point in accordance with the service selected by the Customer pursuant to this tariff and, among other things, shall:

(a) Provide Customer service and support, including call center functions, for services provided by the Company under this tariff;

(b) Respond to service interruptions, reported Gas leaks, and to other Customer safety calls;

(c) Handle connections, curtailments, and terminations for services provided by the Company under this tariff;

(d) Read meters;

(e) Submit bills to Customers for Delivery Service and if contracted by the Supplier, for Supplier Service in accordance with Section 12.2.1.

(f) Address billing inquiries for Delivery Service;

(g) Answer general questions about Delivery Service;

(h) Provide to Suppliers, on request, the data format and procedures for electronic information transfers and funds transfers;

(i) Arrange for or provide Sales Service to the Customer at the request of the Customer in accordance with the Company's tariff; and

(j) Provide information regarding, at a minimum, rate tariffs, billing cycles, Capacity assignment methods, and Consumption Algorithms.

20.2.3 Supplier

The Supplier shall act on behalf of the Customer to acquire Supplies and to deliver them to the Designated Receipt Point pursuant to the service selected by the Customer and the requirements of this tariff.

The Supplier is responsible for enrolling Customers pursuant to Section 20.5 of this tariff.

The Supplier must request, complete and sign a Supplier Service Agreement to act as a Supplier on the Company's system, satisfy the Supplier requirements and practices as set forth in Section 20.3 of this tariff, be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign Capacity, if any, under Section 11, and be and remain eligible to provide service to Customers in New Hampshire.

The Supplier is responsible for completing all transactions with the Company and for all applicable charges associated with Customer enrollment and changes in the Customer's service as set forth in Section 20.5 and Attachment B.

20.3 Supplier Requirements and Practices

20.3.1 The Company shall have the right to establish reasonable financial and non-discriminatory credit standards for qualifying Suppliers. Accordingly, in order to serve Customers on the Company's system, the Supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three (3) years, as well as two (2) trade and two (2) banking references. To the extent that such annual reports to shareholders are not publicly available, the Supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies, and subsidiaries. The Supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The Supplier shall be subject to a credit investigation by the Company. The Company shall review the Supplier's financial position periodically.

20.3.2 The Supplier shall also confirm in the Supplier Service Agreement that:

(a) The Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) The Supplier is not aware of any change in business conditions which would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) The Supplier has no delinquent balances outstanding for services previously provided by the Company, and the Supplier has paid its account according to the established terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding which would materially affect the Supplier's ability to remain solvent as a business entity.

(e) The Supplier's New Hampshire business advertising and marketing materials conform to all applicable state and federal laws and regulations.

20.3.3 In the event the Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company shall require the Supplier to provide one of the following at the Maximum Financial Liability as calculated below:

(a) Advance deposit;

(b) Letter of credit;

(c) Surety bond; or

(d) Financial guaranty from a parent company that meets the creditworthiness criteria.

The Company shall base the Supplier's maximum financial liability as two (2) times the highest month's aggregated Gas Usage of all Customers currently served by the Supplier at the highest Monthly Index in the preceding twenty-four (24) Months. This amount may be updated continuously, and at minimum, whenever the aggregated Gas Usage of all Customers served by the Supplier changes by more than 25%. The Supplier agrees that the Company has the right to access and apply the deposit, letter of credit, or bond to any payment of any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other amounts owed to the Company, or to secure additional Gas supplies, including payment of the costs of the Gas supplies themselves, the cost of transportation storage, and other related costs incurred in bringing those Gas supplies into the Company's system. The Supplier shall continue its obligation to maintain its financial security instrument until it has satisfied all of its outstanding claims with the Company. The Supplier's financial security as established above must be in place no later than five (5) Business Days prior to the first day of each calendar month in order for the Supplier to maintain its eligibility to provide service to Customers.

20.3.4 The Supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of Supplies which it desires the Company to transport to its Customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these Gas supplies to the Designated Receipt Point.

20.3.5 The Supplier shall warrant to the Company that it has good title to or lawful possession of all Gas delivered to the Company at the Designated Receipt Point on behalf of the Supplier or the Supplier's Customers. The Supplier shall indemnify the Company and hold it harmless from all suits, actions, debts, accounts, damages, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said Gas.

20.3.6 The Supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates, or permits to enable Gas to be delivered to the Company's system.

20.3.7 By agreeing to provide service under this tariff, the Supplier acknowledges that adherence to any applicable law regarding unfair trade practices, truth in advertising law, or law of similar import is required. Any Supplier found by a court of competent jurisdiction to have willfully or repeatedly violated the New Hampshire Consumer Protection Act, N.H.R.S.A. Ch. 358-A; the Federal Trade Commission Telemarketing Sales Rules, 16 C.F.R. Part 310; or the regulations promulgated pursuant to the Federal Trade Commission Act, 15 U.S.C. § 45 (a) (1), may be suspended or disqualified from acting as a Supplier on the Company's system.

20.3.8 If the Supplier fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement (e.g., failure to deliver Gas or late payment of bills rendered or failure to execute a capacity assignment), the Company maintains the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system. Written notice of such an intent to terminate the Supplier's eligibility shall be given to the Supplier, its Customers, and the NHPUC. Notification to the Supplier shall be via Registered U.S. Mail - Return Receipt Requested or other means of documented delivery. Upon issuance of such written notice, the Company shall have the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system at the expiration of ten (10) Gas Days after the giving of such notice, unless within such ten (10) Gas Day period the Supplier shall remedy to the full satisfaction of the Company such failure. Termination of such Supplier eligibility for any such cause shall be a cumulative remedy as to the Company, and shall not release the Supplier from its obligation to make payment of any amount or amounts due or to become due from the Supplier to the Company under the Company's applicable tariffs. Customers whose Supplier's deliveries have been terminated will be placed on Sales Service pursuant Section 13 of this tariff.

20.4 Access to Usage History and Current Billing Information

The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to requesting the Company to release the Company's historic usage information specific to that Customer to such Supplier.

The Company shall be required to provide the most recent twelve (12) months of a Customer's historic usage data to a Supplier, provided that the Supplier has received the appropriate authorization as set forth above.

20.5 Enrollment, Cancellation, and Termination of Supplier Service

20.5.1 The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to initiating Supplier Service to the Customer.

20.5.2 The Supplier must provide the Company with the following minimum information in the Company's predetermined format prior to the commencement or termination of service by the Supplier pursuant to Section 20.5 of this tariff:

(a) The Customer's name and current Authorization Number;

(b) The name of the Supplier;

(c) The Customer's billing option (for commencement of service);

(d) The type of change in Supplier Service (e.g., commencement of service, termination of service, or cancellation of service due to the rescission of an agreement with the Supplier by the Customer); and

(e) Any additional information reasonably required by the Company.

The Company shall determine whether each Customer's enrollment request as provided by a Supplier is complete and accurate, and matches the Customer's account record. In the event that the enrollment request is incomplete, inaccurate, or does not match the Customer's account record, then the Company will notify the Supplier so that the Supplier can resolve any discrepancies.

20.5.3 A change in Supplier Service will normally be made on a monthly metering and billing cycle basis, with changes taking effect on the date of the Customer's next scheduled meter read. Enrollment forms must be transmitted no less than ten (10) Business Days prior to the Customer's next scheduled meter read. If more than one Supplier submits a Supplier Service transaction for a given Customer during the monthly billing cycle, the first completed transaction that is received during the cycle shall be accepted. All other transactions shall be rejected. Rejected transactions may be resubmitted after the Customer's next scheduled meter read.

20.5.4 If the Supplier submits information to the Company to terminate Supplier Service to a Customer less than ten (10) Gas Days before the next scheduled meter read, Supplier Service shall be terminated on the date of the Customer's subsequent scheduled meter read. The Company shall confirm the termination date for Supplier Service.

20.5.5 In those instances when a Customer who is receiving Supplier Service from an existing Supplier initiates such service with a new Supplier, the Company shall send the date for the Customer's change in Supplier Service to the existing Supplier. To terminate Supplier Service with a Supplier and to initiate Sales Service, a Customer shall so inform the Company and the Supplier. Supplier Service shall be terminated on the date of the Customer's next scheduled meter read provided that the Company receives notice of such termination no less than ten (10) days in advance of the next scheduled meter read. Where such notice is received by the Company in less than ten (10) days in advance of the next scheduled read, the termination shall be effective as of the date of the following scheduled read. The Company shall send the Customer's termination date for Supplier Service to the Supplier.

20.5.6 A Customer who moves within the Company's service territory shall have the opportunity to notify its existing Supplier that it seeks to continue Supplier Service with said Supplier. Upon such notification, the Supplier may enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer at the new location. The Company shall make the necessary adjustments to the Supplier's affected Aggregation Pools, including but not limited to, changes to Designated Receipt Points, and quantities of Capacity for assignment, if any, pursuant to this tariff and the Supplier's Service Agreement with the Company. In the event that the existing Supplier does not enroll the Customer for Supplier Service at the new location, the Company shall arrange for or provide Sales Service to the Customer.

20.5.7 In those instances when a new Customer moves to the Company's service territory, the Customer's Supplier must enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer. Otherwise, the Customer shall receive Sales Service in accordance with Section 13.

20.5.8 The Company may charge fees to the Supplier for processing the transactions described in this Section, as approved by the NHPUC. These fees are included in Attachment D.

20.6 Aggregation Pools

20.6.1 The aggregation of Customer accounts into an Aggregation Pool is limited by the Delivery Service of the respective Customers. Non-daily metered Customers subscribing to Delivery Service under Rate Schedules G-41, G-42, G-51 and G-52 must be aggregated in a separate pool from Customers subscribing to daily metered service under Rate Schedules G-43, G-53, and G-54.

20.6.2 Non-daily metered Customers taking Delivery Service pursuant to Section 10 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.3 Daily metered Customers taking Delivery Service pursuant to Section 9 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.4 A separate Supplier account will be established for each Supplier Aggregation Pool.

20.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

20.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Attachment B.

20.7 Imbalance Trading

20.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company's provision of information on Supplier imbalances for said Month.

20.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.

20.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

20.7.4 Daily imbalance trades must be point-specific on those Gas Days when the Transporting Pipeline required the Company to balance on a point-specific basis.

20.8 Billing and Payment

20.8.1 By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the prior Month. The Company will provide Suppliers with their Customers' consumption data based on estimated or actual meter readings at the appropriate cycle read dates for each Customer in the Aggregation Pool pursuant to Section 12 of this tariff. This data will be provided on a rolling basis as readings or estimates are made.

20.8.2 Calculation of the charges applicable to the Aggregation Pool will be based on aggregated Gas Usage and other such indicators of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, including but not limited to imbalance charges, credits or penalties, shall be billed to the Supplier on a calendar month basis.

20.8.3 The Supplier shall have ten (10) Business Days from the date of such statement to render payment to the Company. The Supplier shall render payment by means of electronic funds transfer to the Company. The late payment rate will apply to all amounts outstanding after ten (10) days.

20.8.4 If the correctness of the Company's bill to the Supplier is questioned or disputed by the Supplier, an explanation should be promptly requested from the Company. If the bill is determined to be incorrect, the Company shall issue a corrected bill. In the event that the Supplier and the Company fail to agree on the amount of the bill, the Supplier may file a complaint with the Commission to resolve such complaint.

21 CUSTOMER DESIGNATED REPRESENTATIVE

21.1 The Customer may appoint a Designated Representative to satisfy or undertake the Customer's duties and obligations; including, but not limited to submitting and/or receiving notices, making nominations, arranging for trades of imbalances, and performing operational and administrative tasks; provided, however, that under no circumstances will the appointment of a Designated Representative relieve the Customer of the responsibility to make full and timely payment to the Company for all Delivery Service provided under this tariff.

21.2 A request by a Designated Representative to the Company that contains the Customer's Authorization Number will be deemed to be confirmation that the Customer has designated such person or entity as a Designated Representative. A Customer may appoint only one (1) Designated Representative per account.

21.3 Under any agency established hereunder, the Company shall rely upon information concerning the applicable Customer's Delivery Service that is provided by the Designated Representative. All such information shall be deemed to have been provided by the Customer. Similarly, any notice or other information provided by the Company to the Designated Representative concerning the provision of Delivery Service to such Customer shall be deemed to have been provided to the Customer. The Customer shall rely upon any information concerning Delivery Service that is provided to the Designated Representative as if that information had been provided directly to the Customer.

21.4 The Customer shall agree to indemnify the Company and hold it harmless from any liability (including reasonable legal fees and expenses) that the Company incurs as a result of the Designated Representative's negligence or willful misconduct in its performance of agency functions on the Customer's behalf.

IV. ATTACHMENTS

1 ATTACHMENT A
Supplier Service Agreement

Field Cod

GAS SUPPLIER SERVICE AGREEMENT

This Agreement made this **[day]** day of **[month]**, 20**[xx]**, between Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, a New Hampshire Corporation with a principal place of business at 15 Buttrick Road, Londonderry, NH 03053 (the "Company") and **[name of supplier]**, a **[state]** company with a principal place of business at **[address]** ("Supplier"). The Company and the Supplier is also individually referred to herein as a "Party" or collectively as the "Parties."

BASIC UNDERSTANDINGS

Whereas, the Company operates as a natural gas local distribution company and provides firm transportation of third- party gas on its distribution system; and

Whereas, the Company's Tariff (the "Tariff") on file with, and approved by, the New Hampshire Public Utilities Commission (the "NHPUC") permits delivery service customers to assign their rights of nominating and scheduling delivery of gas for transportation on the Company's system to a third-party natural gas supplier; and

Whereas, Supplier seeks to nominate and schedule delivery of gas for distribution on the Company's system on behalf of one or more customers taking delivery service from the Company; and

Whereas, the Company's Tariff, Part III, Section 20.2.3, requires Supplier to enter into this Supplier Service Agreement (the "Agreement") with the Company prior to the initiation of Supplier Service, as defined therein; and

Now therefore, the Parties hereto, each in consideration of the agreement of the other, do hereby agree as follows:

I. SCOPE AND APPLICATION

1.0 This Agreement shall be subject to the Company's Tariff as on file with the NHPUC and in effect from time to time. The Company's Tariff and applicable Rate Schedules are hereby incorporated by reference as though directly set forth herein. In the event the terms of this Agreement conflict with the Company's Tariff, the Tariff shall control.

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Field Cod

1.1 This Agreement is intended for use between the Company and natural gas suppliers providing service to customers on the Company's distribution system, and may not be waived, altered, amended, or modified, except as provided herein.

1.2 Exhibits A and B, attached hereto and incorporated herein by reference, include additional terms that are a part of this Agreement.

II. DEFINITIONS

2.0 Any capitalized terms used in this Agreement and not defined herein shall be as defined in the Tariff or as stated in the NHPUC's regulations.

III. TERM

3.0 This Agreement shall become effective on the date hereof (the "Effective Date") and shall continue in full force and effect from month to month unless terminated by either Party by written notice given no less than thirty (30) days prior to the desired termination date, or unless otherwise agreed by the Parties. Notwithstanding the foregoing, the Parties agree to abide by all terms of this Agreement until any transactions that are outstanding at the time of termination are completed, including, but not limited to, the payment by Supplier to the Company of any and all outstanding balances.

3.1 Notwithstanding anything to the contrary elsewhere in this Agreement or in the Company's Tariff, any Party, by written notice to the other Party (the "Breaching Party") may terminate this Agreement, in whole or in part, with respect to such Breaching Party or suspend further performance without terminating this Agreement upon the occurrence of any of the following:(a) the Breaching Party terminates or suspends doing business; (b) the Breaching Party becomes subject to any bankruptcy or insolvency proceeding under federal or state law (unless removed or dismissed within sixty (60) days from the filing thereof), or becomes insolvent, becomes subject to direct control of a transferee, receiver or similar authority, or makes an assignment for the benefit of creditors; or (c) the Breaching Party commits a material breach of any of its obligations under this Agreement or the Tariff and has not cured such breach within fifteen (15) days after receipt of a written notice from the other Party specifying the nature of such.

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3.2 Consistent with the provisions of Part III, Section 20.3.8 of the Company's Tariff, the Company also maintains the right to terminate the Supplier's eligibility to act as a Supplier. on the Company's system in the event that Supplier fails to comply with or perform any of the obligations on its part established in the Tariff or in this Agreement, including but not limited to, failure to deliver gas or to make payment of amounts due to the Company.

3.3 Notwithstanding the Effective Date, Supplier acknowledges and agrees that the Company is obligated to provide services pursuant to this Agreement only upon full satisfaction, or the Company's express written waiver, of the Conditions Precedent set forth in Article IV of this Agreement.

3.4 No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

3.5 The enumeration of the foregoing remedies shall not be deemed a waiver of any other remedies to which either Party is legally entitled.

IV. CONDITIONS PRECEDENT

4.0 The following requirements shall be conditions precedent to the Company's obligations hereunder:

(a) Supplier shall provide the Company with all information requested in Exhibits A and B attached hereto and incorporated herein;

(b) Pursuant to Part Ill, Section 20.3.1 of the Company's Tariff, the Company shall confirm the Supplier's creditworthiness. In the event that Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company will identify such deficiencies to the Supplier, and the Supplier shall provide financial assurances as required by the Company consistent with the provisions of Part III, Section 20.3.3;

(c) Pursuant to Part Ill, Section 20.2.3 of the Company's Tariff, Supplier shall register with the NHPUC and provide evidence of such to the Company on an annual basis;

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(d) Pursuant to Part III, Section 20.2.3 of the Company's Tariff, Supplier shall demonstrate to the Company that it is an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity;

(e) Pursuant to Part III, Section 12.2.1 of the Company's Tariff, where Supplier elects to utilize the Standard Complete Billing Services from the Company, Supplier shall furnish to the Company a complete schedule of its relevant rates and rate pricing options for Supplier Service in written form or in an electronic format reasonably acceptable to the Company, at Company's option, no less than ten (10) Business Days prior to initial Customer enrollment for any such rate or prior to a change in Supplier's existing rates or five (5) Business Days prior to a change in rate pricing options.

(f) Prior to Customer Enrollment, Supplier shall successfully complete testing of the business-transaction communication protocols established by the Company, which may include communication by fax or telephone, electronic transactions as specified by the Company, or any other applicable communication requirements set forth by the Company.

V. SUPPLIER CERTIFICATION

5.0 In addition to the requirements listed in Section IV of this Agreement, and pursuant to Part III, Section 20.3.2 of the Company's Tariff, the Supplier hereby affirms the following:

(a) Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) Supplier is not aware of any change in business conditions that would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) Supplier has no delinquent balances outstanding for services previously provided by the Company, and Supplier has paid its account according to the established

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terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding that would materially affect Supplier's ability to remain solvent as a business entity.

(e) Supplier's New Hampshire business advertising and marketing materials conform to all applicable New Hampshire state and federal laws and regulations.

5.1 Supplier shall promptly notify Company of any material change in its financial condition as it relates to Supplier's creditworthiness or solvency as a business enterprise.

5.2 In the event that the NHPUC enacts regulations whereby Supplier must register with the NHPUC, Supplier shall notify Company within twenty-four (24) hours in writing in the event that its registration as a Competitive Supplier is acted upon by the NHPUC in such a way that it materially affects Supplier's performance under this Agreement, including but not limited to suspension, revocation, modification, or non-renewal. Consistent with Part III, Section 20.3.8 of the Company's Tariff, revocation or non-renewal of Supplier's registration shall be grounds for immediate termination of this Agreement by Company.

VI. <u>NOMINATIONS AND SCHEDULING</u>

6.0 The Company and Supplier, pursuant to the Company's Tariff on file with the NHPUC and the terms of this Agreement, agree to exchange and act on information regarding the nomination and scheduling of gas for transportation on behalf of Supplier's customers.

6.1 Supplier acknowledges and agrees that its transportation rights under this Agreement are solely those that have been assigned to it by the Customer pursuant to the Company's Tariff. Supplier further agrees that the Company shall have no obligation to honor any nomination or scheduling request from Supplier that, in the Company's sole judgment, exceeds the scope of Supplier's assigned rights or where such nominations or requests could be reasonably refused, directly or indirectly, based on the terms of this Agreement or the Company's Tariff.

6.2 Pursuant to Part III, Sections 9.3.2 and 10.3.3 of the Company's Tariff, nominations will be communicated to the Company in accordance with the terms of this Agreement as set forth in Exhibit A.

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6.3 In the event of a discrepancy between the volume nominated to the Company by Supplier and the volume confirmed by the Company, the discrepancy shall be allocated between and among Supplier's Aggregation Pools and/or Customers in accordance with the Pre-Determined Allocation Method set forth in Exhibit B, attached hereto. In the event that the Supplier has not provided the Company with a Pre-Determined Allocation Method, the discrepancy will be allocated consistent with the provisions of the Company's Tariff.

VII. CAPACITY ASSIGNMENTS

7.0 The Supplier's Maximum Daily Peaking Quantity ("MDPQ") may be modified during the calendar year in accordance with the provisions of Part Ill, Sections 11.0 and 14.0 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.1 Pursuant to Part III, Section 11.9.2 of the Company's Tariff, the quantity of each Company Managed Supply assigned to Supplier may be modified during the calendar year in accordance with Part III, Sections 11.4 and 11.8 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.2 In accordance with Part Ill, Sections 11.0 and 14.0 of the Company's Tariff, the quantity of Capacity assigned to Supplier may be modified during the calendar year. In addition, the Company shall have the right to adjust a Customer's total capacity quantity C'TCQ") if the Company determines that the TCQ calculation is in error or is otherwise not calculated in accordance with the provisions of Part Ill, Sections 11.3.2.

7.3 Pursuant to Part Ill, Section 11.10.2 of the Company's Tariff, Supplier shall provide notice to the Company of its designation of contracts to be managed by the Company for cost mitigation purposes by the means set forth in Exhibit 8.0.

VIII. LEFT BLANK INTENTIONALLY (RESERVED FOR FUTURE USE)

IX. BILLING AND PAYMENT

9.0 Bills, fees and charges for services provided by the Company, including, but not limited to, monthly cashouts, monthly imbalance charges, daily imbalance charges, and any other applicable charges set forth in the Tariff or in this Agreement, shall be

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rendered to Supplier on a monthly basis and shall be due upon receipt of said bill, unless otherwise specified in Exhibit A.

In addition to any other right or remedy available to the Company, Supplier's failure to make payment within ten (10) days of the posting date on the bill shall result in the addition of interest on any unpaid balance calculated at the maximum monthly rate allowable by the Company's Tariff. Interest shall accrue commencing from the date said bill was posted. The posting date is the date the bill is transmitted to Supplier. The bill may also be transmitted electronically if agreed to between the Parties in Exhibit A.

9.1 The Company shall have the right to deduct any amounts owed by Supplier to the Company for such services, which are thirty (30) days or more past due, from any amounts collected in the normal course of business by the Company on the Supplier's behalf. Amounts subject to a good faith dispute will not be subject to deduction.

9.2 The Parties agree to cooperate and provide each other with necessary documentation relating to any transactions resulting hereunder, including but not limited to, applicable sales or other tax exemptions. The Parties agree that Supplier's failure to comply with the provisions of this Article IX shall constitute default of payment under the Tariff and expose Supplier to liability thereunder as well as under this Agreement.

9.3 Consistent with the provisions of Part III, Sections 20.3.1 and 20.3.3 of the Company's Tariff, Supplier shall satisfy the creditworthiness standards established by the Company. In the event the Supplier has not demonstrated satisfaction of the Company's creditworthiness standards, the Supplier shall provide, upon ten (10) days written notice from the Company, financial assurance in the form of an advance deposit, letter of credit, surety bond or financial guaranty from a parent company, as reasonably determined by the Company. The amount of any such financial assurance required by the Company shall be calculated in accordance with the provisions of Part III, Section 20.3.3 of the Company's Tariff. The Company shall review Supplier's satisfaction of the Company's creditworthiness standards every twelve (12) months during the term of this Agreement giving consideration to Supplier's payment history

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in the preceding twelve-month period. Upon the request of Supplier, the Company shall exercise its sole reasonable discretion to determine whether a change in the form of financial assurance is warranted. In the event that the Company requires financial assurances in the form of a deposit, such deposits shall accrue interest in accordance with the Company's Tariff. Such deposit shall be returned to Supplier within thirty (30) days of the expiration or termination of this Agreement, provided that Supplier is not in default under this Agreement. The Company may deduct from the deposit any amount payable to the Company by Supplier under this Agreement, which has not been paid by the Supplier when due, unless such non-payment relates to a documented billing dispute between Supplier and the Company. Such deduction may be taken by the Company without notice or demand of any kind and the Company may, in its sole discretion, apply such deposit against any amount then due and payable. In the event that Company applies all or any portion of such deposit, Supplier shall deposit such sums as are necessary to replenish the security deposit to its maximum amount, within ten (10) days' notice of such deduction and application.

X. REPRESENTATIONS

10.0 Each Party represents that it is and shall remain in compliance with all applicable laws, tariffs, and NHPUC regulations during the term of this Agreement.

10.1 Each person executing this Agreement for the respective Parties represents and warrants that he or she has authority to bind that Party.

10.2 Each Party represents that (a) it has the full power and authority to execute, deliver, and perform this Agreement; (b) the execution, delivery, and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party; and (c) this Agreement constitutes that Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

10.3 Each Party shall exercise all reasonable care, diligence and good faith in the performance of its duties pursuant to this Agreement, and carry out its duties in accordance with applicable recognized professional standards.

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XI. NONDISCLOSURE

11.0 Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third Party, including affiliates of such Party, without the express prior written consent of the other Party. As used herein, the term "Confidential Information" shall include, but not be limited to, all business, financial, and commercial information pertaining to the Parties, Customers of either or both Parties, Suppliers for either Party, personnel of either Party; any trade secrets; and other information of a similar nature; whether written or in intangible form that is marked proprietary or confidential with the appropriate owner's name.

11.1 Confidential Information shall not include information known to either Party prior to obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a Party who was under an obligation of confidentiality to the other Party to this Agreement, or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own Confidential Information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information. Each receiving Party shall, upon termination of this Agreement or at any time upon the request of the disclosing Party, promptly return or destroy all Confidential Information of the disclosing Party then in its possession.

11.2 Notwithstanding the preceding, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential Information pursuant to any applicable law, regulation, ruling, or order, provided that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority; and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so that it may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of any injunction to prohibit such disclosure.

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11.3 No provision of this Agreement shall prohibit the Company from communicating to its Customers and prospective customers, information regarding Supplier's eligibility to conduct business on the Company's distribution system. In addition, obligations under this Article XI shall survive the termination or expiration of this Agreement.

XII. LIABILITY AND INDEMNIFICATION

12.0 The Parties acknowledge and agree that the Force Majeure provisions set forth in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.1 The Parties acknowledge and agree that the liability and indemnification provisions in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.2 For purposes of such liability and indemnification, however, the Parties acknowledge and agree that nothing in such Tariff prohibits one Party from impleading the other Party as a third-party defendant, whether or not one or both Parties are named as defendants in the initial claim of a third party. The third-party claim shall be stayed pending resolution of any dispute regarding liability and indemnification under this Agreement. Such resolution shall be final and binding upon the Parties only after agreement between the Parties or after entry of a final judgment, after any further appeals of a court of competent jurisdiction to which any appeal may have been taken from the determination of the arbitrator(s).

12.3 The Parties acknowledge and agree that for purposes of Part III, Section 17 the Company's Tariff, a Party seeking recovery from the other Party in connection with the performance of its obligations of the Tariff shall not be entitled to recovery where its own negligent acts or omissions contribute to or cause such damages, costs, fines, penalties or liabilities.

12.4 The Parties expressly acknowledge and agree that the dispute resolution provision in Article XIII of this Agreement shall apply to any and all disputes arising under this Article, including, without limitation, those disputes that arise as a result of either of

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the Parties being named as a defendant in the primary action or being named as a third-party defendant by a defendant in the primary action.

12.5 Notwithstanding anything in this Agreement or the Tariff to the contrary, in no event shall any Party hereto be liable to any other Party hereto for indirect, consequential, punitive, special, or exemplary damages under any theory of law that is now or may in the future be in effect, including without limitation: contract, tort, N.H.R.S.A. Ch. 358-A, strict liability, or negligence.

12.6 Notwithstanding the availability of other remedies at law or in equity, either Party hereto shall be entitled to specific performance to remedy a breach of this Agreement by the other Party.

12.7 Supplier further agrees that it shall indemnify, defend and hold harmless the Company with respect to any claim, suit, damages or costs of any kind arising from any action or inaction of the Company in reliance upon the nominations, scheduling instructions or other communications from Supplier. The Parties agree that reliance on such instructions and communications shall be deemed reasonable and shall not constitute negligence.

12.8 The provisions of this Article XII shall survive the termination of this Agreement.

XIII. DISPUTE RESOLUTION

13.0 Disputes hereunder shall be reduced to writing and referred to the Parties' representatives for resolution. The Parties' representatives shall meet and make all reasonable efforts to resolve the dispute. Pending resolution, the Parties shall continue to fulfill their obligations under this Agreement in good faith, unless this Agreement has been suspended or terminated. If the Parties fail to resolve the dispute within thirty (30) days, they may mutually agree to pursue mediation or arbitration to resolve such issues.

13.1 The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of New Hampshire, without regard to the doctrines governing choice of law. All disputes arising hereunder shall be brought either before the NHPUC or the state courts of the State of New Hampshire.

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XIV. COMMUNICATIONS

14.0 Except as otherwise provided herein, any notices given under this Agreement shall be in writing and shall be delivered to the Company as set forth in Exhibit A, by hand or sent by (a) certified mail, return receipt requested, first class postage prepaid, (b) telecopy, or (c) a nationally recognized courier service. Notices and other communications to Supplier shall also be addressed as shown on Exhibit A. Notices given hereunder shall be deemed to have been given upon receipt or any refusal to accept; telecopied notices shall be deemed to have been given upon confirmation of their receipt.

14.1 All communications required by the Company's Tariff shall be made in accordance with the schedule listed in Exhibit A. Information on active Company fax numbers and e-mail addresses shall be posted on the Company's Internet Website at http://www.libertyutilities.com/east/gas/business_partners/index.html

XV. ENFORCEABILITY

15.0 In the event that any portion or part of this Agreement is deemed invalid, against public policy, void or otherwise unenforceable by a court of law, the validity and enforceability of the remaining portions thereof shall otherwise be fully enforceable.

15.1 No waiver by any Party of any one or more defaults by the other Party in the performance of any provision of this Agreement shall operate or be construed as a waiver of any other present or future default, whether of a like or different character. No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights.

XVI. ASSIGNMENT AND DELEGATION

16.0 Any entity that shall succeed by purchase, merger or consolidation to the assets and properties, substantially or as an entity, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

16.1 Either Party may, without relieving itself of its obligations under this Agreement, assign any of its rights or obligations hereunder to an affiliated entity, but otherwise no assignment of this Agreement or any of the rights or obligations hereunder shall

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be made unless there first shall have been obtained the written consent of the other Party. No assignment by Supplier shall take effect until the assignee has met the requirements of Article IV hereunder. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee.

16.2 The restrictions on assignment contained herein shall not in any way prevent either Party from pledging or mortgaging its rights as security for its indebtedness.

16.3 In addition, either Party may subcontract its duties under this Agreement to a subcontractor provided that the subcontracting Party shall remain fully responsible as a principal and not as a guarantor for performance of any subcontracted duties, and shall serve as the point of contact between its subcontractor and the other Party, and the subcontractor shall meet the requirements of any applicable laws, rules, regulations, and Tariff. The assigning or subcontracting Party shall provide the other Party with thirty (30) calendar days' prior written notice of any such subcontracting or assignment, which notice shall include such information about the subcontractor as the other Party shall reasonably require.

XVII. MISCELLANEOUS

17.0 This Agreement, all Exhibits and attachments hereto and all documents referenced herein, constitute the entire agreement between the Parties and supersedes all other agreements, communications, and representations. Paragraph headings are for convenience only and are not to be construed as part of this Agreement.

17.1 Unless otherwise provided herein, no modification of, or supplement to, the terms and provisions stated in this Agreement shall be or become effective without the written consent of both Parties.

17.2 This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed to be an original but all of which shall constitute one and the same document.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

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In witness whereof, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the date above.

[SUPPLIER NAME]

By ______________________ Title______________________

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

By ______________________ Title______________________

2 ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.23 per MMBtu of Daily Imbalance Volumes	
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
		Capacity for Mitigation.	
III.	Peaking Demand Charge	$ 11.39	MMBTU of Peak MDQ
IV.	Company Allowance Calculation (per Schedule 25)		
		152,544,340	Total Sendout - Therms Aug-2015 - Jul-2016
		148,757,282	Total Throughput - Therms Aug-2015 - Jul-2016
		3,787,058	Variance (Sendout - Throughput)
	Company Allowance Percentage 2016-17	2.5%	Variance / Total Sendout

3 ATTACHMENT C
Capacity Allocators

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	48.3%	19.3%	32.4%	100.0%
G-51	Low Annual /Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-42	Medium Annual / High Winter	48.3%	19.3%	32.4%	100.0%
G-52	High Annual / Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-43	High Annual / High Winter	48.3%	19.3%	32.4%	100.0%
G-53	High Annual / Load Factor < 90%	75.4%	9.2%	15.4%	100.0%
G-54	High Annual / Load Factor < 90%	75.4%	9.2%	15.4%	100.0%

EXHIBIT
tabbies
#29
DG 17-048

State of New Hampshire
Public Utilities Commission

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

Docket No. DG 17-048

Agreement Regarding Permanent Rates

This Agreement Regarding Permanent Rates (the "Agreement") is entered into this 27th day of February, 2018, by Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") and the Office of the Consumer Advocate ("OCA") (together, the "Settling Parties"). This Agreement resolves all issues between the Settling Parties in this proceeding, the approval of which would discharge the Commission's duty to "be the arbiter between the interests of the customer and the interests of the regulated utilities." RSA 363:17-a.

I. INTRODUCTION

On March 28, 2017, Liberty filed its notice of intent to file rate schedules seeking an increase in its annual distribution revenues. The Company filed its proposed rate schedules on April 28, 2017, seeking, as updated later in the proceeding and through its rebuttal testimony, a $14.5 million permanent increase in annual distribution revenues and a $5.2 million step increase to recover an annual revenue deficiency based on additional net rate base of approximately $252 million for the twelve-month period ending December 31, 2017. The Company requested approval of a 10.3% return on equity (ROE), and a capital structure consisting of 50% equity and 50% debt. Liberty also proposed consolidating the Keene Division's distribution rates into EnergyNorth's distribution rates (while maintaining a separate cost of gas ("COG") rate for Keene) and implementing a full decoupling mechanism to sever the connection between sales and revenue. The Company supported its filing with the direct testimony of a number of witnesses from the Company and expert consultants. The Commission suspended the rate schedules by Order No. 26,015 (May 8, 2017).

The OCA notified the Commission that it would participate in the docket on behalf of residential customers consistent with RSA 363:28. No party sought intervention.

The Company's filing also included a request for a temporary rate increase of $7.8 million. The Settling Parties and Staff reached a settlement as to temporary rates, and the Commission approved the agreed $6.75 temporary rate increase, effective July 1, 2017. Order No. 26,035 (June 30, 2017). The order provides that any permanent rates approved by the Commission would be fully reconcilable back to the July 1, 2017, effective date of temporary rates.

Following the temporary rate order, the Company responded to numerous sets of data requests from the parties, the Commission's Audit Staff reviewed the Company's filing and issued its audit report, and the OCA and Staff filed testimony.

Staff's testimony recommended the following: (1) an ROE of 8.55%; (2) a capital structure of 49.85% long term debt, 0.95% short term debt, and 49.21% equity; (3) a permanent increase to distribution revenue of $4.045 million; (4) a step increase of $4.1 million for 2017 capital additions and recovery of certain costs related to pensions, benefits, and 2017 degradation fees; (5) that the Commission deny the Company's request to consolidate the Keene Division's distribution rates with the rest of the Company; and (6) a limited decoupling mechanism to account only for energy efficiency gains, as opposed to the Company's (and OCA's) proposed "full" decoupling proposals that remove all incentives for the Company to encourage higher sales per customer.

The OCA's testimony recommended an ROE of 8.4%, a 50/50 capital structure, a permanent increase to distribution revenue of $9.2 million, a separate rate proceeding for the Keene Division, and a full "real time" decoupling proposal that adjusts each customer's bill based on their actual use and actual heating degree days during the current billing month and periodically adjusts for other decoupling variables.

The Company conducted discovery on Staff's and OCA's testimony, and the Company filed rebuttal testimony. The parties then engaged in settlement discussions that resulted in this Agreement, which is intended to resolve all issues in this case as between the OCA and Liberty. The Settling Parties recommend and request that the Commission approve this Agreement without modification.

II. TERMS OF AGREEMENT

A. Revenue Requirement, Rate Base, Rate of Return

The Settling Parties agree and recommend that the Commission authorize an annual distribution revenue increase of $10.3 million effective May 1, 2018, based on an overall cost of capital of 6.85%. The overall cost of capital was calculated utilizing a cost of equity of 9.4%, the actual weighted average cost of long-term debt, and a capital structure of 0.945% short-term debt, 49.845% long-term debt, and 49.209% common equity capital, which is the Company's proforma capital structure based on the recent long-term debt issuance and short-term debt approved in Order No. 26,084 (Dec. 15, 2017). The calculation of the overall cost of capital is as follows:

Description	Capital Structure	Cost of Capital	Weighted Cost of Capital
Common Stock	49.21%	9.40%	4.63%
Long-Term Debt	49.85%	4.42%	2.20%
Short-Term Debt	0.95%	2.49%	0.02%
	100.00%		6.85%

The Settling Parties agree that the above distribution revenue increase represents a reasonable compromise of all the issues relating to the revenue requirement pending before the Commission for the purpose of permanent rates, as itemized below. Because the above revenue increase is the result of compromise and settlement, it is a liquidation of all revenue requirement issues. The Settling Parties agree that the revenue requirement recommended to the Commission in this Agreement results in permanent rates for Liberty's customers that are just and reasonable. The permanent rate increase described in this Section A shall be reconcilable to the effective date of temporary rates in this case, July 1, 2017, per Order No. 26,035, in accordance with Section C below.

The liquidated revenue requirement in this Agreement reflects consideration, negotiation, and resolution as between the Settling Parties of all the issues raised by the OCA and by Staff in their direct testimony that impacted the revenue requirement. Some of the more significant topics are discussed below.

1. Prepayments Included in Cash Working Capital

The Company included prepayments of certain costs (mostly property taxes and insurance) in its cash working capital calculation. Staff recommended that the Company remove all prepayments claiming those costs were double counted because they were included in rate base and were also used to determine cash working capital. The Company acknowledged that there may be some double-counting in theory, but it did not warrant a dollar-for-dollar offset as Staff testified. The Settling parties have negotiated and compromised this issue in reaching this Agreement.

2. Materials and Supplies

Staff recommended that Liberty move $3.66 million in "materials and supplies" (which consists of fuel supply inventories) from rate base and instead recover the associated revenue requirement through the Company's COG rate. The Settling Parties agree with this adjustment and these costs were removed from the distribution revenue requirement.

3. Concord Training Center

The Training Center located on the Company's property in Concord has been in use since March 2015. The facility provides a centralized location for simultaneous training of multiple employees in a controlled environment and has been and is being used to, among other things, train and test gas field workers and supervisors whose Operator Qualification requirements continue to increase, train electrical field workers and supervisors, and train office staff so they may better perform their jobs (e.g., training call center employees on the basics of the Company's gas and electric systems makes them better able to respond to customer questions) The Training Center also serves as a call center back-up facility, has been used for industry training in conjunction with other utilities, has been used to host meetings with first responders, and for other related purposes. With respect to electric training, the Company currently receives revenue from its affiliate, Granite State Electric, pursuant to a lease agreement that is on file with the Commission in Docket No. DA 16-560, which docket was consolidated into the current docket. The Settling Parties agree that the lease should continue under its existing terms and conditions.

The revenue requirement in this Agreement allows the Training Center costs and revenues to be included in the determination of the revenue requirement, but also reflects consideration and compromise of the issues related to the Training Center raised by Staff and the OCA in their testimony.

4. **Depreciation and Amortization**

a. The depreciation and amortization rates to be used by Liberty on a going-forward basis are the rates set forth in Attachment A.

b. The depreciation and amortization rates applied to the assets for EnergyNorth and the Keene Division will be aligned so they conform with the rates in Attachment A.

c. Plant assets for the Keene Division will become subject to group depreciation.

d. As a housekeeping matter, certain EnergyNorth plant assets that are currently recorded in transmission-related plant accounts will be reclassified to distribution-related plant accounts.

e. The depreciation reserve variance is an under-recovery of $8.9 million, and will be amortized over a five-year period, resulting in annual amortization of $1,780,000.

f. As part of its next rate case, Liberty will prepare an updated analysis of the status of the depreciation reserve variance, with determination of the disposition of the updated variance and the appropriate amortization period to be determined in that proceeding.

5. iNATGAS

In Docket No. DG 14-091 the Commission approved a special contract with iNATGAS, which included the construction of a CNG facility in Concord. The Company ultimately built a larger facility, at greater cost, essentially accelerating the construction of Phase 2. Staff recommended that the Company not recover some of the costs of the facility because, in Staff's view, it was not appropriate to build Phase 2 so soon, because the actual costs exceeded the original budget, and because the current revenue from the project did not support the costs. Liberty explained how the higher costs were reasonable, that it was more cost effective to complete Phase 2 early, and that iNATGAS is now buying CNG from the facility at a rate that exceeds the minimum take-or-pay amounts in the Special Contract so as to support all the direct costs of the facility.

The revenue requirement in this Agreement reflects a compromise of these issues related to iNATGAS.

6. Keene Production Costs and Emergency Response Costs

The Settling Parties agree that the emergency response costs related to the December 2015 incident and the Keene production costs should be recovered through the Keene specific COG rates over five years during the winter COG period, and beginning November 1, 2018.

B. Step Increase

The Settling Parties agree that the Company shall be permitted to implement a step increase to its distribution revenue, as calculated in Attachment B, effective May 1, 2018, to recover the following items:

1. The revenue requirement associated with 2017 non-growth related capital additions placed in service as of December 31, 2017;

2. The increase to operating expenses resulting from the Financial Accounting Standards Board's ("FASB") issuance in March 2017 of Accounting Standards Update No. 2017-07 ("ASU 2017-07");[1] and
3. The costs incurred during 2017 for degradation fees paid to the City of Manchester and legal costs incurred by the Company associated with a lawsuit that began in 2012 against the Cities of Concord and Manchester to challenge the "degradation fees" that the cities charged Liberty to dig in municipal streets.
4. Certain "carryover' costs related to the Company's Cast Iron/Bare Steel replacement program as discussed during the hearing in Docket No. DG 17-063.[2]

The 2017 non-growth related capital additions referenced in Section B.1. above and included in Attachment B are based on Liberty's 2017 capital budget. On or before March 30, 2018, Liberty will submit its actual capital costs for its 2017 non-growth related capital additions and update Attachment B. In the event that the resulting revenue requirement is lower than $5,044,835, the lower amount will be used for the step adjustment. If the updated calculation of the revenue requirement exceeds $5,044,835, the revenue requirement will be limited to $5,044,835.

C. Effective Date for Permanent Rates and Recoupment

The permanent rate increase agreed to in Section II.A shall be effective for all service rendered on and after May 1, 2018. The difference between the distribution revenues obtained

[1] Among other things, ASU 2017-07 amended the accounting for pension and OPEB costs, effective January 1, 2018, to limit the components of net periodic pension and postretirement benefit costs that are eligible for capitalization to only the service costs component. Previously, all components of net periodic pension and postretirement benefit costs (i.e., service cost, interest cost, expected return on plan assets, etc.) were eligible to be capitalized. The result of the accounting changes prescribed in ASU 2017-07 is that the portions of the costs that are no longer eligible to be capitalized increase the Company's operating expenses as compared to prior accounting.
[2] *See* transcript of June 19, 2017 hearing in Docket No. DG 17-063 at 41, et seq.

from the rates prescribed in the temporary rate order, Order No. 26,035, and the distribution revenues that would have been obtained under the rates finally determined, if applied during the period such temporary rate order was in effect, shall be recovered from customers over a period of twenty months, beginning with service rendered as of May 1, 2018. The total estimated amount of recoupment is $3,590,667 as shown on Attachment C, and shall be recovered through a uniform charge per therm through the Local Delivery Adjustment Clause (LDAC) of the Company's tariff. The estimated amount of recoupment has been calculated using actual billing data for July 1, 2017, through December 31, 2017, and estimated billing data for January 1, 2018, through April 30, 2018. On or before June 30, 2018, Liberty will file with the Commission, for its review and approval, the actual recoupment amount based on actual billing data for the period July 1, 2017, through April 30, 2018. Any difference between the actual recoupment amount and the estimated amount shown on Attachment C will be reconciled through the operation of the reconciling mechanism in the LDAC.

D. Rate Case Expenses

Subject to adjustment for the difference between estimated and actual expense, the Company shall recover $530,000 in rate case expenses over a period of twenty months commencing with service rendered as of May 1, 2018. Details of the actual and estimated rate case expenses are included in Attachment D. The Company agrees to submit by June 30, 2018, an accounting of its rate case expenses, with appropriate supporting documentation, for review by the parties and approval by the Commission. The Company shall recover its just and reasonably incurred rate case expenses through the LDAC in the same manner as it recovers the temporary rate recoupment. Once the final amount of actual, just and reasonable rate case expenses is determined, any difference between the amount recovered commencing May 1, 2018, and the final amount shall be recovered through the operation of the reconciling mechanism in the LDAC. Rate case expenses shall be recovered through uniform charge per therm in accordance with the provisions of the LDAC.

E. Revenue Allocation and Rate Design

The permanent and step increases will be allocated to each class on a proportional basis by increasing each class' revenue responsibility by the same percentage.

For residential rate design, the R-3 customer charge and the R-1 customer charge will both be set at $14.88 per month, which is $2.00 per month lower than the currently effective customer charge for Rate R-1. Any revenue shortfall resulting from the reduction to the customer charges, plus the increase resulting from the permanent and step increases, will be recovered through the volumetric delivery per therm rates. In addition, the volumetric head and tail block delivery per therm rates for R-3 will be set at the same level.

The distribution rates for the R-4 Low Income Residential Heating rate class were calculated by multiplying the R-3 proposed base distribution rates by 40 percent to reflect a 60 percent discount. This resulted in a customer charge of $5.95 (i.e., $14.88 x 40%) and a volumetric delivery per therm rate of $0.2400 (i.e., $0.6000 x 40%).

Rates for commercial and industrial rate classes will be increased proportionally for each billing rate component (e.g., customer charge and volumetric delivery rate) to recover the allocated revenues for that class. The resulting rates are effective May 1, 2018, and continue without modification to rate design until the Company's next rate proceeding.

F. Decoupling

The Settling Parties agree that the Company should implement a "full" decoupling mechanism that contains the following elements: (1) real-time weather normalization, calculated at the individual customer level; (2) revenue per customer design, with accrual calculations at the rate class level and billing rates aggregated into two rates – Residential and C&I; (3) Managed Expansion Program customers are subject to decoupling, but the expansion surcharge dollars (i.e., the 30% distribution premium) are excluded from the decoupling calculation; and (4) special contract customers are not subject to decoupling and will be excluded entirely from the decoupling calculation.

The real-time weather normalization adjustment is calculated as the difference between actual distribution revenue billed to each customer in each billing cycle for each month, and what distribution revenue for each customer's bill would have been based on normalized therm deliveries. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

The annual revenue per customer adjustment will be determined by calculating the difference between actual annual distribution revenue per customer and approved annual distribution revenue per customer for two groups of customers: (a) the residential classes and (b) the commercial and industrial classes. Approved annual distribution revenue per customer for each of these two groups will be based on the approved distribution revenues and test year average customer counts for each group. The difference in total distribution revenues is calculated using this revenue per customer variance multiplied times the actual average annual customer count. This amount will be recovered from or refunded to each group over the subsequent 12-month period through a uniform charge per therm for each group.

The Settling Parties agree that the Company may recover up to $50,000 in costs incurred to upgrade its billing system and related software to implement this decoupling mechanism. Any costs above $50,000 will be absorbed by the Company.

The Settling Parties agree that the decoupling mechanism shall take effect beginning on November 1, 2018. On that date, decoupling will replace the Lost Revenue Adjustment Mechanism established in Order No. 25,932 (Docket No. DE 15-137), and the Company will cease any and all recovery of lost revenues attributable to energy efficiency programs outside of the decoupling mechanism.

G. Keene Consolidation

The Settling Parties agree that Keene Division customers will pay the same distribution rates and be served under the same terms and conditions as all other Liberty customers, effective May 1, 2018.

Liberty will not commence construction on any phase of its proposed Keene expansion unless a discounted cash flow ("DCF") analysis of the revenue requirement of the direct cost versus the incremental revenue of the additional load for that phase shows a positive value over a 10-year period.

Liberty agrees to a target amount of additional revenue due to growth in excess of the revenue requirement associated with the direct cost of the investment. If the cumulative excess revenue is less than $200,000 annually, Liberty will reduce its revenue requirement in its next rate case by the difference between $200,000 and the excess revenue. Excess revenue shall be based on actual load added as of the effective date of permanent rates following the end of the next rate case, plus reasonably anticipated revenue based on customer commitments to take service, both pro-formed for one year following the effective date of permanent rates in the next rate case. This provision is conditioned on Liberty's receipt of the Safety Division's authorization to commence construction of Phase I no later than May 1, 2018, and on acquiring appropriate authorization to construct a permanent compressed natural gas ("CNG")/liquefied natural gas ("LNG") facility by May 1, 2019.

Keene customers will begin paying the LDAC as of May 1, 2018.

Keene shall have a separate COG, which will include: (1) propane purchases; (2) CNG/LNG purchases; (3) production costs; (4) revenue requirement associated with CNG/LNG facilities; and (5) revenue requirement associated with fuel inventory.

H. Impact of Tax Reform

Separate from the revenue requirement described in this Agreement, Liberty will reduce annual distribution revenues by $2,394,065 to account for the reduction in federal tax rates included in the Tax Cuts and Jobs Act of 2017 ("2017 Tax Act") that was passed by the United States Congress in December 2017 and a reduction to New Hampshire tax rates, and which reduction will be part of the rate adjustments that occur on May 1, 2018. The calculation of this adjustment is shown in Attachment E. In addition, the tax law changes included in the 2017 Tax Act, including the elimination of bonus depreciation for tax purposes, have been taken into account in the calculation of the step adjustment described in Section B above.

The Settling Parties recommend that the Commission find that this provision fully satisfies the Company's obligations with respect to Order No. 26,096 (January 3, 2018) in Docket No. IR 18-001.

I. Bill Impacts

Bill impacts for the various rate classes resulting from the adjustments to revenue and rate design as described above are provided in Attachment F.

J. Tariff Changes

Liberty will file revised tariff language to add Keene as a service territory served by Liberty Utilities (EnergyNorth Natural Gas) Corp., and to add a Keene COG tariff specific to Keene customers, as described above.

Liberty will cancel the Keene Division tariff as of May 1, 2018.

K. Residential Low Income Assistance Program

The Settling Parties agree that the Commission should open a generic proceeding to address changes to the Residential Low Income Assistance Program.

L. Next Distribution Rate Case

Liberty shall file its next distribution rate case using a test year ending no later than December 31, 2020.

III. CONDITIONS

This Agreement is expressly conditioned on the Commission's acceptance of all its terms, without change or condition. If the Commission does not accept this Agreement in its entirety, without change or condition, or if the Commission makes any findings that go beyond the scope of this Agreement, and either of the Settling Parties notifies the Commission within five business days of its disagreement with any such changes, conditions, or findings, the Agreement shall be deemed to be withdrawn, in which event it shall be deemed to be null and void and without effect, shall not constitute any part of the record in this proceeding, shall not be relied on by any party to this proceeding or by the Commission for any other purpose.

The Settling Parties agree that the Commission's approval of this Agreement will not constitute continuing approval of, or precedent for, any particular principle or issue related to the revenue requirement, but such acceptance does constitute a determination that the adjustments and provisions stated in their totality are just and reasonable and consistent with the public interest and that the revenues contemplated will be just and reasonable under the circumstances.

The discussions that produced this Agreement have been conducted on the understanding that all offers of settlement and settlement discussions relating to this docket shall be confidential, shall not be admissible as evidence in this proceeding, shall be without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in connection with any future proceeding or otherwise.

As between the Settling Parties, the information and testimony previously provided in this proceeding are not expected to be subject to cross-examination by the Settling Parties, which would normally occur in a fully litigated case. The Settling Parties agree that they shall not object to the admission as full exhibits of their respective direct and rebuttal testimony and supporting documentation. The Settling Parties' agreement to admit all testimony without challenge does not constitute agreement by the Settling Parties that the content of the written testimony is accurate or what weight, if any, should be given to the views of any witness. The identification of the resolution of any specific issue in this Agreement does not indicate any of the Settling Parties' agreement to that resolution for purposes of any future proceeding, nor does the reference to any other document bind the Settling Parties to the contents of, or recommendations in, that document for purposes of any future proceeding. The Commission's approval of the recommendations in this Agreement shall not constitute a determination or precedent with regard to any specific adjustments to the revenue requirement, but rather shall constitute only a determination that the revenue requirement and rates resulting from, and other specific conditions stated in this Agreement are just and reasonable. The Settling Parties agree to forego cross-examining each others' witnesses regarding their pre-filed testimony and, therefore, the admission into evidence of any such witness's testimony or supporting documentation shall not be deemed in any respect to constitute an admission by any party to this Agreement that any allegation or contention in this proceeding is true or false, except that the sworn testimony of any witness shall constitute an admission by such witness.

This Agreement may be executed by facsimile and in counterparts, each of which shall be deemed to be an original, and all of which, taken together, shall constitute one agreement binding on all Settling Parties.

Dated: February 27, 2018

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

By its Attorney, Michael J. Sheehan

Dated: February 27, 2018

Office of the Consumer Advocate

By the Consumer Advocate, D. Maurice Kreis

FERC Account		Average Service Lives (Years)	Net Salvage Value (%)	Depreciation Rate	
303	Intangible Plant (Amort.)				
	3-Year	3	N/A	33.33%	
	5-Year	5	N/A	20.00%	
	10-Year	10	N/A	10.00%	
	Production Plant				
305	Structures and Improvements	35	0.0	2.86%	
311	Liquid Petroleum Gas Equipment	35	0.0	2.86%	
319	Gas Mixing Equipment	20	0.0	5.00%	
320	Other Equipment - LNG	35	0.0	2.86%	
	Storage Plant				
361	Structures and Improvements - LNG	35	0.0	2.86%	
363	Other Equipment - LNG	35	0.0	2.86%	
	Transmission Plant				
366	Structures and Improvements	35	0.0	2.86%	(reclass to 375)
367	Mains	60	-15.0	1.92%	(reclass to 376)
369	Measuring and Regulating Station Equipment	35	0.0	2.86%	(reclass to 378)
	Distribution Plant				
375	Structures and Improvements	35	0.0	2.86%	
376	Mains	60	-15.0	1.92%	
378	Measuring and Regulating Station Equipment	35	0.0	2.86%	
380	Services	45	-60.0	3.55%	
381	Meters	33	0.0	3.03%	
381.1	Meters - Instrument	33	0.0	3.03%	
381.2	Meters - ERTs	20	0.0	5.00%	
382	Meter Installations	33	0.0	3.03%	
387	Other Equipment	19	0.0	5.26%	
	General Plant				
390	Structures and Improvements	30	0.0	3.33%	
391	Office Furniture and Equipment	18	5.0	5.28%	
391.1	Office Furniture and Equipment - Computers	11	0.0	9.09%	
391.2	Office Furniture and Equipment - Laptop Comp.	5	0.0	20.00%	
392	Transportation Equipment	5	0.0	20.00%	
393	Stores Equipment	30	0.0	3.33%	
394	Tools, Shop and Garage Equipment	19	0.0	5.26%	
396	Power Operated Equipment	5	0.0	20.00%	
397	Communications Equipment	10	0.0	10.00%	
398	Miscellaneous Equipment	12	0.0	8.33%	

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Liberty Utilities (EnergyNorth)
Step Increase - EnergyNorth and Keene

Line	Description	Misc. Intangible Plant	LNG Plant	Mains	Station Equipment	General-Structures	Mains	Meas. & Reg. Station Equip.	Services	Meters	Structures and Improvements	Office Equipment	Vehicles	Stores Equipment	Tools	Total
	FERC Account	*303*	*320*	*367*	*369*	*375*	*376*	*378*	*380*	*381*	*390*	*391*	*392*	*393*	*394*	
1	Capital Spending - EnergyNorth	$ 2,105,141	$2,020,000	$ 14,414,334	$ 300,000	$ 1,215,000	$ 300,000	$ 325,000	$ 1,115,000	$1,600,000	$ 1,156,662	$ 760,384	$ 1,978,000		$ 175,000	$ 27,464,521
2	Capital Spending - Keene	25,000		236,000				55,000	50,000	10,000		65,000	45,000	4,000		$ 490,000
3	Capital Spending - Total	2,130,141	2,020,000	14,650,334	300,000	1,215,000	300,000	380,000	1,165,000	1,610,000	1,156,662	825,384	2,023,000	4,000	175,000	$ 27,954,521
4																
5	Deferred Tax Calculation															
6	Tax Method	MACRS15	MACRS20	MACRS20	MACRS20	MACRS39	MACRS20	MACRS20	MACRS20	MACRS20	MACRS39	MACRS7	MACRS5	MACRS7	MACRS7	
7	Tax Depreciation Rate	5.00%	3.75%	3.75%	3.75%	1.28%	3.75%	3.75%	3.75%	3.75%	1.28%	14.29%	20.00%	14.29%	14.29%	
8																
9	Bonus Depreciation @ 0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10																
11	Tax Basis	$ 2,130,141	$ 2,020,000	$ 14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
12	MACRS Depreciation	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	$ 1,450,946
13																
14	Tax Depreciation - Federal	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	$ 1,450,946
15	Tax Depreciation - State	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	
16																
17	Book Depreciation Rate - EN	16.13%	2.86%	1.92%	2.86%	2.86%	1.92%	2.86%	3.55%	3.03%	3.33%	5.28%	20.00%	3.33%	5.26%	
18	Book Depreciation - EN	$ 339,559	$ 57,772	$ 276,755	$ 8,580	$ 34,749	$ 5,760	$ 9,295	$ 39,583	$ 48,480	$ 38,517	$ 40,148	$ 395,600	$ -	$ 9,205	$ 1,304,003
19	Book Depreciation Rate - Keene	16.13%		1.92%				2.86%	3.55%	3.03%		5.28%	20.00%	3.33%		
20	Book Depreciation - Keene	$ 4,033		$ 4,531				$ 1,573	$ 1,775	$ 303		$ 3,432	$ 9,000	$ 133		$ 24,780
21	Book Depreciation - Total	$ 343,592	$ 57,772	$ 281,286	$ 8,580	$ 34,749	$ 5,760	$ 10,868	$ 41,358	$ 48,783	$ 38,517	$ 43,580	$ 404,600	$ 133	$ 9,205	$ 1,328,783
22																
23	Tax over (under) Book - Federal - EN	$ (237,085)	$ 17,978	$ 268,101	$ 2,670	$ (19,172)	$ 5,490	$ 3,382	$ 2,330	$ 11,592	$ (23,688)	$ 74,332	$ -	$ 438	$ 15,795	$ 122,163
24	Tax over (under) Book - State - EN	(237,085)	17,978	268,101	2,670	(19,172)	5,490	3,382	2,330	11,592	(23,688)	74,332	0	438	15,795	122,163
25	Deferred Taxes - Federal @ 19.28% - EN	(45,705)	3,466	51,685	515	(3,696)	1,058	652	449	2,235	(4,567)	14,330	0	84	3,045	23,551
26	Deferred Taxes - State @ 8.20% - EN	(19,441)	1,474	21,984	219	(1,572)	450	277	191	951	(1,942)	6,095	0	36	1,295	10,017
27	Deferred Tax Balance @ 27.48%	$ (65,146)	$ 4,940	$ 73,669	$ 734	$ (5,268)	$ 1,509	$ 929	$ 640	$ 3,185	$ (6,509)	$ 20,425	$ -	$ 120	$ 4,340	$ 33,568
28																
29	Rate Base Calculation															
30	Plant in Service	$ 2,130,141	$2,020,000	$ 14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
31	Accumulated Depreciation	(343,592)	(57,772)	(281,286)	(8,580)	(34,749)	(5,760)	(10,868)	(41,358)	(48,783)	(38,517)	(43,580)	(404,600)	(133)	(9,205)	(1,328,783)
32	Deferred Tax Balance	65,146	(4,940)	(73,669)	(734)	5,268	(1,509)	(929)	(640)	(3,185)	6,509	(20,425)	0	(120)	(4,340)	(33,568)
33	**Rate Base**	$ 1,851,695	$1,957,288	$ 14,295,379	$ 290,686	$ 1,185,519	$ 292,731	$ 368,203	$ 1,123,002	$1,558,032	$ 1,124,654	$ 761,379	$ 1,618,400	$ 3,746	$ 161,455	$ 26,592,170
34																
35	Revenue Requirement Calculation															
36	Return on Rate Base @ 8.60%	$ 159,246	$ 168,327	$ 1,229,403	$ 24,999	$ 101,955	$ 25,175	$ 31,665	$ 96,578	$ 133,991	$ 96,720	$ 65,479	$ 139,182	$ 322	$ 13,885	$ 2,286,927
37	Depreciation Expense	343,592	57,772	281,286	8,580	34,749	5,760	10,868	41,358	48,783	38,517	43,580	404,600	133	9,205	1,328,783
38	Property Tax @ 2.06% - EN Capital		41,512	296,222	6,165	24,969	6,165	6,679			23,770					405,483
39	Insurance @ 0.20% - EN Capital		3,983	28,421	592	2,396	592	641	2,198	3,155	2,281	1,499	3,900		345	50,001
40	Property Tax @ 4.17% - Keene Capital			9,838				2,293	2,084	417						14,633
41	Insurance @ 4.25% - Keene Capital			10,032				2,338	2,125	425		2,763	1,913	170		19,767
42	**Annual Revenue Requirement**	**$ 502,837**	**$ 271,594**	**$ 1,855,203**	**$ 40,336**	**$ 164,068**	**$ 37,692**	**$ 54,484**	**$ 144,344**	**$ 186,770**	**$ 161,288**	**$ 113,321**	**$ 549,595**	**$ 625**	**$ 23,435**	**$ 5,044,835**

Line	Rate of Return Calculation	Portion	After-Tax Cost	Tax	Pre-Tax WACC
45	Equity	49.20%	9.40%	27.48%	6.38%
46	Debt (ST)	0.95%	2.49%		0.02%
47	Debt (LT)	49.85%	4.42%		2.20%
48		100.00%			8.60%

Line	**"Carry Over Cost Provision Adjustments" per DG 17-063, Knepper Direct Testimony**		
45	Unadjusted annual revenue requirement for FY 16	694,182	
46	Adjusted annual revenue requirement for FY 16	688,807	
47	Difference to be recovered		5,375
48			
49	Estimated paving cost for FY 17	2,301,960	
50	Recoverable paving cost for FY 17	899,390	
51	Difference to be recovered	1,402,570	
52	Revenue Requirement of the Difference, per CIBS model		155,703

Line	**Description - Property Tax and Insurance Rates for EnergyNorth**	**Reference**	**Amount**	
51	Property taxes (Account 408-P)	RR-StepWP2	$ 9,386,306	
52	Property insurance (Account 924)	RR-EN-2-1		$ 38,113
53	Injuries and Damage (Casualty Insurance) (Account 925)	RR-EN-2-1		877,844
54			$ 9,386,306	$ 915,957
55	Plant at Cost	RR-Step-EN-WP2	$ 456,742,424	$ 464,553,396
56	As % of Plant Cost		2.06%	0.20%

Line	New Tax Rate Analysis	
59	Federal Tax Rate	21.00%
60	State Tax Rate	8.20%
61	Combined Tax Rate	27.48%

Line	**Adjustments Identified in Rebuttal Testimony**	**Reference**	**Amount**
60	Increase in Expense Portion of Pension and OPEB Costs	Response to Staff Tech 3-15	419,583
61	Legal Fees, 2017	Laflamme & Mullinax Direct, Schedule EN 4, Line 27	172,517
62	Degradation Fees, 2017	Laflamme & Mullinax Direct, Schedule EN 4, Line 35	186,065
63			
64	Total Additional Expense - Goes to Line 35		778,165

Line	**Description - Property Tax and Insurance Rates for Keene**	**Reference**	**Amount**	
67	Property taxes (Account 408-P)	RR-K-2-1	153,854	
68	Property insurance (Account 924)	RR-K-2-1		(2,183)
69	Injuries and Damage (Casualty Insurance) (Account 925)	RR-K-2-1		187,292
70			153,854	185,109
71	Plant at Cost	RR-Step-K-WP2	3,690,589	4,354,606

Priority	Project	Company	Project Description	CY2017 Capital Budget	FERC Account
LU CapEx - Growth	8840-1753	EnergyNorth	Install Main on Varney and Worthely and Rockland	$ 350,000	367
LU CapEx - Improvement	8840-1721	EnergyNorth	Install Security Equipment - EN Facilities	$ 125,000	391
LU CapEx - Improvement	TBD	EnergyNorth	Northeast Expansion		367
LU CapEx - Improvement	8840-1722	EnergyNorth	Inactive Service Program	$ 75,000	380
LU CapEx - Improvement	8840-1723	EnergyNorth	Main & Service Replacement City/State Construction	$ 5,200,000	367
LU CapEx - Improvement	8840-1725	EnergyNorth	Service Replacement Fitting City/State Construction	$ 60,000	380
LU CapEx - Improvement	8840-1726	EnergyNorth	LNG/LPG Capital Improvements	$ 100,000	320
LU CapEx - Improvement	8840-1727	EnergyNorth	Facility Improvements & Additions - Various	$ 100,000	375
LU CapEx - Improvement	8840-1728	EnergyNorth	Upgrade Hi Line - Concord to Tilton Phase 2	$ 350,000	367
LU CapEx - Improvement	8840-1729	EnergyNorth	Pre-Code Stee Pipe Protection Program	$ 175,000	367
LU CapEx - Improvement	8840-1730	EnergyNorth	IT - Software, Equipment & Infrastructure	$ 50,000	303
LU CapEx - Improvement	8840-1731	EnergyNorth	Gas System Planning & Reliability	$ 500,000	367
LU CapEx - Improvement	8840-1732	EnergyNorth	Gas System Control & Regulation	$ 300,000	369
LU CapEx - Improvement	8840-1733	EnergyNorth	Facility Improvements & Additions - Manchester	$ 200,000	391
LU CapEx - Improvement	8840-1734	EnergyNorth	Facility Improvements & Additions - Nashua	$ 100,000	391
LU CapEx - Improvement	8840-1735	EnergyNorth	Facility Improvements & Additions - Tilton	$ 200,384	391
LU CapEx - Improvement	8840-1736	EnergyNorth	Facility Improvements & Additions - Londonderry	$ 75,000	391
LU CapEx - Improvement	8840-1737	EnergyNorth	Facility Improvements & Additions - Concord	$ 60,000	391
LU CapEx - Improvement	8840-1738	EnergyNorth	IT Systems Allocations - Corporate	$ 750,000	303
LU CapEx - Improvement	8840-1739	EnergyNorth	Dresser Coupling Replacement Program	$ 300,000	376
LU CapEx - Improvement	8840-1740	EnergyNorth	ERP Foundation Year	$ 536,463	303
LU CapEx - Improvement	8840-1741	EnergyNorth	EAM Foundation Year	$ 536,463	303
LU CapEx - Improvement	TBD	EnergyNorth	CIS Foundation Year	$ -	303
LU CapEx - Improvement	8840-1742	EnergyNorth	GIS Gas Upgrade	$ 118,544	303
LU CapEx - Improvement	8840-1743	EnergyNorth	GIS - One Graphic Card	$ 15,440	303
LU CapEx - Improvement	8840-1744	EnergyNorth	GIS Marketing Enhancement	$ 51,177	303
LU CapEx - Improvement	8840-1745	EnergyNorth	Mobiletech Enhancements	$ 37,054	303
LU CapEx - Improvement	8840-1746	EnergyNorth	Concord Office	$ 500,000	390
LU CapEx - Improvement	8840-1755	EnergyNorth	Motorized Gate for Concord Plant	$ 55,000	375
LU CapEx - Improvement	8840-1756	EnergyNorth	Nashua Meter Building Repointing	$ 150,000	375
LU CapEx - Improvement	8840-1757	EnergyNorth	CNG Fast Fill Station for Manchester and Tilton Yards	$ 1,920,000	320
LU CapEx - Improvement	8840-1758	EnergyNorth	Manchester Solar Install	$ 190,000	380
LU CapEx - Improvement	8840-1759	EnergyNorth	Paving Manchester Yard	$ 900,000	375
LU CapEx - Improvement	TBD	EnergyNorth	Paving Nashua Yard	$ -	375
LU CapEx - Improvement	8840-1762	EnergyNorth	Tilton Office Refresh	$ 600,000	390
LU CapEx - Improvement	8840-1763	EnergyNorth	Manchester Kitchen Refresh	$ 35,000	390
LU CapEx - Improvement	8840-1764	EnergyNorth	Supplemental AC for Londonderry (Dispatch/Training Rms)	$ 21,000	390
LU CapEx - Improvement	8840-1765	EnergyNorth	Tilton Yard Shelving Replacement	$ 8,662	390
LU CapEx - Improvement	8840-1766	EnergyNorth	Chestnut Street, Nashua Regulator Station Replacement	$ 325,000	378
LU CapEx - Improvement	8840-1769	EnergyNorth	Laconia Phase II	$ 850,000	367
LU CapEx - Improvement	8840-1770	EnergyNorth	Daniel Webster Highway	$ 650,000	367
LU CapEx - Improvement	8840-C18800	EnergyNorth	Upgrade Hi Line - Concord to Tilton Phase 1	$ 700,000	367
LU CapEx - Replenishment	8840-1701	EnergyNorth	Reserve for Unidenfitied Mandated/Growth Projects	$ 3,139,334	367
LU CapEx - Replenishment	8840-1702	EnergyNorth	Meter Protection Program	$ 50,000	381
LU CapEx - Replenishment	8840-1703	EnergyNorth	Cathodic Protection Program	$ 750,000	367
LU CapEx - Replenishment	8840-1704	EnergyNorth	Replacement Services Random (Non Leaks)	$ 490,000	380
LU CapEx - Replenishment	8840-1705	EnergyNorth	Replacement Services Random (Due to Leaks)	$ 300,000	380
LU CapEx - Replenishment	8840-1706	EnergyNorth	Meter Work Project (Changes)	$ 150,000	381
LU CapEx - Replenishment	8840-1707	EnergyNorth	Meter Work Project (Meter Purchases)	$ 1,300,000	381
LU CapEx - Replenishment	8840-1708	EnergyNorth	Corrosion & Miscellaneous Fitting	$ 100,000	367
LU CapEx - Replenishment	8840-1709	EnergyNorth	Valve Installation/Replacement	$ 50,000	367
LU CapEx - Replenishment	8840-1710	EnergyNorth	Leak Repairs	$ 250,000	367
LU CapEx - Replenishment	8840-1713	EnergyNorth	Main Replacement Fitting LPP	$ 200,000	367
LU CapEx - Replenishment	8840-1714	EnergyNorth	K Meter Replacement Program	$ 100,000	381
LU CapEx - Replenishment	8840-1715	EnergyNorth	Aldyl-A Replacement Program	$ 550,000	367
LU CapEx - Replenishment	8840-1716	EnergyNorth	Main Replacement Reactive	$ 100,000	367
LU CapEx - Replenishment	8840-1717	EnergyNorth	Dispatch and Control Center	$ 10,000	375
LU CapEx - Replenishment	8840-1718	EnergyNorth	Purchase Misc Capital Equipment & Tools	$ 175,000	394
LU CapEx - Replenishment	8840-1719	EnergyNorth	Transportation Fleet and Equipment Purchases	$ 1,978,000	392
LU CapEx - Replenishment	8840-1720	EnergyNorth	SCADA Capital Improvements	$ 10,000	303
LU CapEx - Replenishment	8840-1767	EnergyNorth	Replace Mueller Stopping Equipment w/ TD Williamson	$ 500,000	367
		EnergyNorth	Bond Refund for Concord Training Center	$ (8,000)	390
LU CapEx - Improvement	8843-1704	Keene	Facility Improvements & Additions - Keene	$ 5,000	391
LU CapEx - Improvement	8843-1705	Keene	IT - Software, Equipment & Infrastructure	$ 25,000	303
LU CapEx - Improvement	8843-1706	Keene	Facility Improvements & Additions - Keene	$ 45,000	391
LU CapEx - Improvement	8843-C18750	Keene	Install Security Equipment - Keene	$ 15,000	391
LU CapEx - Improvement	8843-ENI103	Keene	Main Replacement City/State Construction	$ 50,000	367
LU CapEx - Improvement	8843-ENI137	Keene	Service Replacement City/State Construction	$ 20,000	380
LU CapEx - Improvement	8843-REL105	Keene	Gas System Planning & Reliability	$ 50,000	378
LU CapEx - Replenishment	8843-1701	Keene	Reserve for unidentified projects	$ 25,000	367
LU CapEx - Replenishment	8843-1702	Keene	Purchase Misc. Capital Tools/Equipment	$ 4,000	393
LU CapEx - Replenishment	8843-1703	Keene	Transportation Fleet and Equipment Purchases	$ 45,000	392
LU CapEx - Replenishment	8843-ENI006	Keene	Cathodic Protection/Corrosion Mitigation Program	$ 5,000	367
LU CapEx - Replenishment	8843-ENI007	Keene	Replacement Services Random	$ 5,000	380
LU CapEx - Replenishment	8843-ENI100P	Keene	Meter Work Project (Meter Purchases)	$ 10,000	381
LU CapEx - Replenishment	8843-ENI107	Keene	Main Replacement LPP	$ 150,000	367
LU CapEx - Replenishment	8843-ENI117	Keene	Service Replacement LPP	$ 25,000	380
LU CapEx - Replenishment	8843-REL109	Keene	SCADA Capital Improvements	$ 5,000	378
LU CapEx - Replenishment	8843-REL110	Keene	Valve Installation/Replacement	$ 6,000	367

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Docket No. DG 17-048
Calculation of Recoupment Amount

	(A)	(B)
1. Settlement Permanent Rate Increase	$10,300,000	
2. Temporary Rate Increase	$6,750,000	
3. Annual Recoupment		$3,550,000
4. divided by: TY Weather Normal Deliveries (th)*		159,761,663
5. Recoupment per Therm		$0.0222
6. Times: Actual/Estimated Jul-Apr Deliveries (th)**		161,741,745
7. Recoupment		$3,590,667

* Test Year Delivery data from initial filing Schedule Rates-2, p.6
** Time Difference is number of months that Temporary Rates were in effect.
Due to colder than normal temperatures, actual therms for the recoupment period exceeded the annual weather normalized sales.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket No. DG 17-048

Actual/Estimated Deliveries (th) for Recoupment Calculation

	Month	Deliveries	*
1.	Jul-17	5,277,399	A
2.	Aug-17	5,724,645	A
3.	Sep-17	5,838,102	A
4.	Oct-17	8,439,912	A
5.	Nov-17	16,780,042	A
6.	Dec-17	26,501,752	A
7.	Jan-18	26,925,176	E
8.	Feb-18	25,940,404	E
9.	Mar-18	23,074,433	E
10.	Apr-18	17,239,880	E
11.	TOTAL	161,741,745	

* Actual data (A), Estimated data (E)

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Rate Case Expense (Through February 15, 2018)
Docket No. DG 17-048

Purpose	Provider	Amount
Revenue Requirement	Concentric	$ 136,829
Marginal Cost Study	Concentric	70,939
Functional Cost of Service Study	Concentric	14,993
Rate Design	Concentric	35,696
Decoupling	Concentric	29,826
Return on Equity	ScottMadden	39,830
Depreciation Study	MAC	43,444
Legal Notice		1,446
Court Reporter	Patnaude	472
Copying	Minuteman Press	2,753
Staff Consultants		
Revenue Requirement	Blue Ridge Consulting	34,691
Return on Equity	J. Randall Woolridge	-
Follow-Up	Liberty Consulting	57,340
Total through February 15, 2018		$ 468,259
Additional Estimated Expenses through Conclusion of case		61,741
Total Rate Case Expenses (Actual thrrough Feb. 15 plus estimate)		$ 530,000

Permanent rate increase	10,300,000	
Original gross-up	1.6504	
Increase before gross-up	6,240,911	
Gross-up with new tax rates	1.3789	
Revised Grossed-up increase	8,605,593	
Difference in gross-up	(1,694,407)	
Excess DIT (amort. over 39.05 years) *	(699,657)	(27,321,620 / 39.05)
Total annual amount to return to customers	(2,394,065)	

* Revaluing the existind deferred tax assets and liabilities at the lower tax rates resulted in a net amount of excess deferred tax liaiblity of $27,321,620 which will be amortized and returned to customers over the average remaining life of the underlying assets which is 39.05 years.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Winter Season (Jan. - Apr., Nov. - Dec.) / **Summer Season (May - Oct.)**

Residential Non-Heating (R1)

PROPOSED		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		17	24	27	32	31	23	153	19	14	11	9	9	11	73	226
Winter:																
Cust. Chg	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28								
Headblock	$0.4200	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.4200	$6.93	$9.91	$11.48	$13.29	$13.10	$9.51	$64.22								
HB Threshold	-															
Summer:																
Cust. Chg	$14.88								$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28	$178.56
Headblock	$0.4200								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.4200								$8.03	$5.91	$4.50	$3.83	$3.77	$4.64	$30.69	$94.91
HB Threshold	-															
Total Base Rate Amount		$21.81	$24.79	$26.36	$28.17	$27.98	$24.39	$153.50	$22.91	$20.79	$19.38	$18.71	$18.65	$19.52	$119.97	$273.47
COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7346								
COG amount - Winter		$10.64	$15.20	$17.62	$25.50	$25.12	$18.24	$112.33								
COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.5984
COG amount - Summer									$5.99	$4.41	$3.36	$2.86	$2.81	$3.46	$22.89	$135.22
LDAC	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037
LDAC amount		$1.71	$2.45	$2.84	$3.28	$3.23	$2.35	$15.86	$1.98	$1.46	$1.11	$0.95	$0.93	$1.15	$7.58	$23.44
Total Bill		**$34.16**	**$42.44**	**$46.82**	**$56.96**	**$56.33**	**$44.98**	**$281.69**	**$30.89**	**$26.66**	**$23.84**	**$22.51**	**$22.39**	**$24.14**	**$150.44**	**$432.13**

Winter Season (Jan. - Apr., Nov. - Dec.) / **Summer Season (May - Oct.)**

Residential Non-Heating (R1)

CURRENT		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		17	24	27	32	31	23	153	19	14	11	9	9	11	73	226
Winter:																
Cust. Chg	$16.88	$16.88	$16.88	$16.88	$16.88	$16.88	$16.88	$101.28								
Headblock	$0.2231	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.2231	$3.68	$5.26	$6.10	$7.06	$6.96	$5.05	$34.12								
HB Threshold	-															
Summer:																
Cust. Chg	$16.88								$16.88	$16.88	$16.88	$16.88	$16.88	$16.88	$101.28	$202.56
Headblock	$0.2231								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.2231								$4.27	$3.14	$2.39	$2.04	$2.00	$2.47	$16.30	$50.42
HB Threshold	-															
Total Base Rate Amount		$20.56	$22.14	$22.98	$23.94	$23.84	$21.93	$135.40	$21.15	$20.02	$19.27	$18.92	$18.88	$19.35	$117.58	$252.98
COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7346								
COG amount - Winter		$10.64	$15.20	$17.62	$25.50	$25.12	$18.24	$112.33								
COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.5984
COG amount - Summer									$5.99	$4.41	$3.36	$2.86	$2.81	$3.46	$22.89	$135.22
LDAC	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856
LDAC amount		$1.41	$2.02	$2.34	$2.71	$2.67	$1.94	$13.09	$1.64	$1.21	$0.92	$0.78	$0.77	$0.95	$6.25	$19.35
Total Bill		**$32.61**	**$39.37**	**$42.95**	**$52.16**	**$51.63**	**$42.11**	**$260.82**	**$28.78**	**$25.64**	**$23.54**	**$22.55**	**$22.46**	**$23.76**	**$146.73**	**$407.55**

DIFFERENCE:

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill	**$1.55**	**$3.07**	**$3.88**	**$4.80**	**$4.70**	**$2.87**	**$20.87**	**$2.11**	**$1.03**	**$0.30**	**($0.04)**	**($0.07)**	**$0.38**	**$3.71**	**$24.58**
% Change	**4.74%**	**7.80%**	**9.03%**	**9.21%**	**9.11%**	**6.81%**	**8.00%**	**7.34%**	**4.00%**	**1.28%**	**-0.17%**	**-0.32%**	**1.59%**	**2.53%**	**6.03%**
Base Rate	$1.25	$2.64	$3.38	$4.23	$4.14	$2.46	$18.10	$1.77	$0.77	$0.11	($0.20)	($0.23)	$0.18	$2.38	$20.49
% Change	6.07%	11.94%	14.72%	17.68%	17.36%	11.20%	13.37%	8.35%	3.85%	0.56%	-1.08%	-1.24%	0.91%	2.03%	8.10%
COG & LDAC	$0.30	$0.43	$0.49	$0.57	$0.56	$0.41	$2.77	$0.35	$0.25	$0.19	$0.17	$0.16	$0.20	$1.32	$4.09
% Change	2.48%	2.48%	2.48%	2.03%	2.03%	2.03%	2.21%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	2.65%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No																	
72	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
73	**Residential Heating (R3)**																
74	**PROPOSED**																**Total**
75			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
76	**average Usage (Therms)**		51	90	117	141	130	89	618	51	25	16	14	14	22	142	760
77																	
78	**Winter:**																
79	Cust. Chg	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28								
80	Headblock	$0.5775	$29.40	$51.98	$57.75	$57.75	$57.75	$51.12	$305.75								
81	Tailblock	$0.5775	$0.00	$0.00	$10.04	$23.80	$17.16	$0.00	$51.00								
82	HB Threshold	100															
83																	
84	**Summer:**																
85	Cust. Chg	$14.88								$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28	$178.56
86	Headblock	$0.5775								$11.55	$11.55	$9.35	$8.14	$8.12	$11.55	$60.26	$366.02
87	Tailblock	$0.5775								$17.86	$3.10	$0.00	$0.00	$0.00	$0.97	$21.93	$72.93
88	HB Threshold	20															
89																	
90	Total Base Rate Amount		$44.28	$66.86	$82.67	$96.43	$89.79	$66.00	$446.03	$44.29	$29.53	$24.23	$23.02	$23.00	$27.40	$171.47	$617.50
91																	
92	COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7382								
93	COG amount - Winter		$32.81	$58.01	$75.66	$113.76	$104.50	$71.32	$456.05								
94																	
95	COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.6587
96	COG amount - Summer									$15.95	$7.95	$5.07	$4.42	$4.40	$6.79	$44.59	$500.64
97																	
98	LDAC	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037
99	LDAC amount		$5.28	$9.33	$12.17	$14.64	$13.45	$9.18	$64.06	$5.28	$2.63	$1.68	$1.46	$1.46	$2.25	$14.76	$78.82
100																	
101	**Total Bill**		**$82.38**	**$134.20**	**$170.50**	**$224.83**	**$207.73**	**$146.50**	**$966.15**	**$65.52**	**$40.12**	**$30.99**	**$28.90**	**$28.86**	**$36.44**	**$230.82**	**$1,196.97**
102																	
103	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
104	**Residential Heating (R3)**																
105	**CURRENT**																**Total**
106			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
107	**average Usage (Therms)**		51	90	117	141	130	89	618	51	25	16	14	14	22	142	760
108																	
109	**Winter:**																
110	Cust. Chg	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58								
111	Headblock	$0.3863	$19.67	$34.77	$38.63	$38.63	$38.63	$34.20	$204.52								
112	Tailblock	$0.3197	$0.00	$0.00	$5.56	$13.18	$9.50	$0.00	$28.23								
113	HB Threshold	100															
114																	
115	**Summer:**																
116	Cust. Chg	$24.43								$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58	$293.16
117	Headblock	$0.3863								$7.73	$7.73	$6.26	$5.45	$5.43	$7.73	$40.31	$244.84
118	Tailblock	$0.3197								$9.89	$1.72	$0.00	$0.00	$0.00	$0.54	$12.14	$40.37
119	HB Threshold	20															
120																	
121	Total Base Rate Amount		$44.10	$59.20	$68.62	$76.24	$72.56	$58.63	$379.34	$42.04	$33.87	$30.69	$29.88	$29.86	$32.69	$199.03	$578.37
122																	
123	COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7382								
124	COG amount - Winter		$32.81	$58.01	$75.66	$113.76	$104.50	$71.32	$456.05								
125																	
126	COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.6587
127	COG amount - Summer									$15.95	$7.95	$5.07	$4.42	$4.40	$6.79	$44.59	$500.64
128																	
129	LDAC	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856
130	LDAC amount		$4.36	$7.70	$10.05	$12.09	$11.10	$7.58	$52.88	$4.36	$2.17	$1.39	$1.21	$1.20	$1.86	$12.18	$65.06
131																	
132	**Total Bill**		**$81.27**	**$124.91**	**$154.32**	**$202.08**	**$188.16**	**$137.52**	**$888.27**	**$62.35**	**$44.00**	**$37.15**	**$35.50**	**$35.47**	**$41.34**	**$255.80**	**$1,144.07**
133																	
134	**DIFFERENCE:**																
135	**Total Bill**		**$1.11**	**$9.29**	**$16.18**	**$22.75**	**$19.58**	**$8.98**	**$77.88**	**$3.17**	**($3.88)**	**($6.16)**	**($6.60)**	**($6.61)**	**($4.90)**	**($24.98)**	**$52.89**
136	% Change		**1.36%**	**7.44%**	**10.48%**	**11.26%**	**10.40%**	**6.53%**	**8.77%**	**5.08%**	**-8.82%**	**-16.58%**	**-18.59%**	**-18.63%**	**-11.86%**	**-9.77%**	**4.62%**
137																	
138	**Base Rate**		$0.18	$7.66	$14.05	$20.19	$17.23	$7.38	$66.70	$2.25	($4.34)	($6.45)	($6.85)	($6.86)	($5.29)	($27.56)	$39.14
139	% Change		0.42%	12.94%	20.48%	26.49%	23.75%	12.58%	17.58%	5.34%	-12.81%	-21.03%	-22.94%	-22.98%	-16.19%	-13.85%	6.77%
140																	
141	**COG & LDAC**		$0.92	$1.63	$2.12	$2.56	$2.35	$1.60	$11.18	$0.92	$0.46	$0.29	$0.26	$0.25	$0.39	$2.58	$13.76
142	% Change		2.48%	2.48%	2.48%	2.03%	2.03%	2.03%	2.20%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	2.43%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No																	
143	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
144	**Low Income Residential Heating (R4)**																
145	**PROPOSED**																**Total**
146			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
147	**average Usage (Therms)**		46	81	105	127	122	87	568	58	27	17	14	14	20	150	718
148																	
149	**Winter:**																
150	Cust. Chg	$5.95	$5.95	$5.95	$5.95	$5.95	$5.95	$5.95	$35.71								
151	Headblock	$0.2310	$10.71	$18.62	$23.10	$23.10	$23.10	$20.21	$118.84								
152	Tailblock	$0.2310	$0.00	$0.00	$1.19	$6.15	$5.09	$0.00	$12.43								
153	HB Threshold	100															
154																	
155	**Summer:**																
156	Cust. Chg	$5.95								$5.95	$5.95	$5.95	$5.95	$5.95	$5.95	$35.71	$71.42
157	Headblock	$0.2310								$4.62	$4.62	$3.90	$3.31	$3.23	$4.62	$24.30	$143.14
158	Tailblock	$0.2310								$8.71	$1.55	$0.00	$0.00	$0.00	$0.09	$10.35	$22.77
159	HB Threshold	20															
160																	
161	Total Base Rate Amount		$16.66	$24.57	$30.24	$35.20	$34.14	$26.16	$166.98	$19.28	$12.12	$9.85	$9.27	$9.18	$10.66	$70.36	$237.34
162																	
163	COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7398								
164	COG amount - Winter		$29.89	$51.96	$67.78	$101.99	$98.30	$70.47	$420.38								
165																	
166	COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.6507
167	COG amount - Summer									$18.08	$8.37	$5.29	$4.49	$4.38	$6.38	$46.99	$467.38
168																	
169	LDAC	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037
170	LDAC amount		$4.81	$8.36	$10.91	$13.13	$12.65	$9.07	$58.93	$5.98	$2.77	$1.75	$1.49	$1.45	$2.11	$15.55	$74.48
171																	
172	**Total Bill**		**$51.36**	**$84.89**	**$108.93**	**$150.32**	**$145.10**	**$105.70**	**$646.29**	**$43.35**	**$23.26**	**$16.90**	**$15.25**	**$15.01**	**$19.15**	**$132.91**	**$779.19**
173																	
174	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
175	**Low Income Residential Heating (R4)**																
176	**CURRENT**																**Total**
177			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
178	**average Usage (Therms)**		46	81	105	127	122	87	568	58	27	17	14	14	20	150	718
179																	
180	**Winter:**																
181	Cust. Chg	$9.77	$9.77	$9.77	$9.77	$9.77	$9.77	$9.77	$58.62								
182	Headblock	$0.1545	$7.16	$12.45	$15.45	$15.45	$15.45	$13.51	$79.48								
183	Tailblock	$0.1278	$0.00	$0.00	$0.66	$3.40	$2.81	$0.00	$6.87								
184	HB Threshold	100															
185																	
186	**Summer:**																
187	Cust. Chg	$9.77								$9.77	$9.77	$9.77	$9.77	$9.77	$9.77	$58.62	$117.24
188	Headblock	$0.1545								$3.09	$3.09	$2.61	$2.22	$2.16	$3.09	$16.25	$95.74
189	Tailblock	$0.1278								$4.82	$0.86	$0.00	$0.00	$0.00	$0.05	$5.72	$12.60
190	HB Threshold	20															
191																	
192	Total Base Rate Amount		$16.93	$22.22	$25.88	$28.62	$28.03	$23.28	$144.98	$17.68	$13.72	$12.38	$11.99	$11.93	$12.91	$80.60	$225.58
193																	
194	COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7398								
195	COG amount - Winter		$29.89	$51.96	$67.78	$101.99	$98.30	$70.47	$420.38								
196																	
197	COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.6507
198	COG amount - Summer									$18.08	$8.37	$5.29	$4.49	$4.38	$6.38	$46.99	$467.38
199																	
200	LDAC	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856
201	LDAC amount		$3.97	$6.90	$9.00	$10.84	$10.45	$7.49	$48.64	$4.94	$2.29	$1.45	$1.23	$1.20	$1.74	$12.84	$61.48
202																	
203	**Total Bill**		**$50.79**	**$81.08**	**$102.66**	**$141.45**	**$136.78**	**$101.24**	**$614.00**	**$40.70**	**$24.37**	**$19.12**	**$17.71**	**$17.50**	**$21.03**	**$140.43**	**$754.43**
204																	
205	**DIFFERENCE:**																
206	**Total Bill**		**$0.57**	**$3.81**	**$6.27**	**$8.87**	**$8.31**	**$4.46**	**$32.28**	**$2.65**	**($1.11)**	**($2.22)**	**($2.46)**	**($2.50)**	**($1.88)**	**($7.52)**	**$24.76**
207	% Change		**1.12%**	**4.70%**	**6.11%**	**6.27%**	**6.08%**	**4.40%**	**5.26%**	**6.51%**	**-4.57%**	**-11.62%**	**-13.90%**	**-14.26%**	**-8.94%**	**-5.36%**	**3.28%**
208																	
209	**Base Rate**		($0.27)	$2.35	$4.36	$6.58	$6.10	$2.87	$22.00	$1.60	($1.60)	($2.53)	($2.72)	($2.75)	($2.25)	($10.24)	$11.76
210	% Change		-1.60%	10.57%	16.86%	22.98%	21.78%	12.34%	15.17%	9.07%	-11.64%	-20.41%	-22.70%	-23.04%	-17.43%	-12.70%	5.21%
211																	
212	**COG & LDAC**		$0.84	$1.46	$1.90	$2.29	$2.21	$1.58	$10.29	$1.04	$0.48	$0.31	$0.26	$0.25	$0.37	$2.71	$13.00
213	% Change		2.48%	2.48%	2.48%	2.03%	2.03%	2.03%	2.19%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	2.46%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No																
214	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**						
215	**Commercial/Industrial - Low Annual Use, High Winter Use (G-41)**															
216	**PROPOSED**															**Total**
217			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
218	**average Usage (Therms)**		119	248	345	430	391	246	1,778	127	53	27	24	23	43	297	2,075
219																	
220	**Winter:**																
221	Cust. Chg	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67								
222	Headblock	$0.4710	$47.10	$47.10	$47.10	$47.10	$47.10	$47.10	$282.59								
223	Tailblock	$0.3163	$5.97	$46.84	$77.40	$104.32	$92.07	$46.11	$372.71								
224	HB Threshold	100															
225																	
226	**Summer:**																
227	Cust. Chg	$57.44								$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67	$689.33
228	Headblock	$0.4710								$9.42	$9.42	$9.42	$9.42	$9.42	$9.42	$56.52	$339.11
229	Tailblock	$0.3163								$33.91	$10.35	$2.36	$1.16	$0.93	$7.21	$55.92	$428.63
230	HB Threshold	20															
231																	
232	Total Base Rate Amount		$110.52	$151.38	$181.94	$208.86	$196.61	$150.65	$999.96	$100.77	$77.22	$69.23	$68.02	$67.79	$74.07	$457.10	$1,457.06
233																	
234	COG Rate - (Winter)		$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7398								
235	COG amount - Winter		$76.48	$159.58	$221.73	$345.59	$314.45	$197.63	$1,315.45								
236																	
237	COG Rate - (Summer)									$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.6781
238	COG amount - Summer									$39.23	$16.26	$8.47	$7.30	$7.07	$13.20	$91.53	$1,406.98
239																	
240	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
241	LDAC amount		$10.16	$21.21	$29.47	$36.75	$33.44	$21.01	$152.04	$10.88	$4.51	$2.35	$2.02	$1.96	$3.66	$25.38	$177.42
242																	
243	**Total Bill**		**$197.16**	**$332.17**	**$433.14**	**$591.20**	**$544.49**	**$369.30**	**$2,467.45**	**$150.87**	**$97.99**	**$80.05**	**$77.34**	**$76.82**	**$90.93**	**$574.01**	**$3,041.46**
244																	
245	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**						
246	**Commercial/Industrial - Low Annual Use, High Winter Use (G-41)**															
247	**CURRENT**															**Total**
248			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
249	**average Usage (Therms)**		119	248	345	430	391	246	1,778	127	53	27	24	23	43	297	2,075
250																	
251	**Winter:**																
252	Cust. Chg	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70								
253	Headblock	$0.4383	$43.83	$43.83	$43.83	$43.83	$43.83	$43.83	$262.98								
254	Tailblock	$0.2944	$5.56	$43.59	$72.03	$97.09	$85.69	$42.92	$346.87								
255	HB Threshold	100															
256																	
257	**Summer:**																
258	Cust. Chg	$53.45								$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70	$641.40
259	Headblock	$0.4383								$8.77	$8.77	$8.77	$8.77	$8.77	$8.77	$52.60	$315.58
260	Tailblock	$0.2944								$31.56	$9.64	$2.20	$1.08	$0.86	$6.71	$52.04	$398.92
261	HB Threshold	20															
262																	
263	Total Base Rate Amount		$102.84	$140.87	$169.31	$194.37	$182.97	$140.20	$930.55	$93.77	$71.85	$64.42	$63.29	$63.08	$68.93	$425.34	$1,355.89
264																	
265	COG Rate - (Winter)		$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7398								
266	COG amount - Winter		$76.48	$159.58	$221.73	$345.59	$314.45	$197.63	$1,315.45								
267																	
268	COG Rate - (Summer)	$0.4206								$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.6781
269	COG amount - Summer									$39.23	$16.26	$8.47	$7.30	$7.07	$13.20	$91.53	$1,406.98
270																	
271	LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
272	LDAC amount		$8.01	$16.72	$23.23	$28.97	$26.36	$16.57	$119.85	$8.57	$3.55	$1.85	$1.59	$1.55	$2.88	$20.00	$139.86
273																	
274	**Total Bill**		**$187.33**	**$317.17**	**$414.27**	**$568.92**	**$523.77**	**$354.39**	**$2,365.86**	**$141.57**	**$91.67**	**$74.74**	**$72.19**	**$71.69**	**$85.01**	**$536.87**	**$2,902.73**
275																	
276	**DIFFERENCE:**																
277	**Total Bill**		**$9.83**	**$15.00**	**$18.87**	**$22.27**	**$20.72**	**$14.91**	**$101.59**	**$9.30**	**$6.32**	**$5.31**	**$5.16**	**$5.13**	**$5.92**	**$37.14**	**$138.73**
278	% Change		**5.25%**	**4.73%**	**4.55%**	**3.91%**	**3.96%**	**4.21%**	**4.29%**	**6.57%**	**6.89%**	**7.10%**	**7.14%**	**7.15%**	**6.97%**	**6.92%**	**4.78%**
279																	
280	**Base Rate**		$7.68	$10.51	$12.63	$14.49	$13.64	$10.46	$69.41	$7.00	$5.37	$4.81	$4.73	$4.71	$5.15	$31.76	$101.17
281	% Change		7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.46%
282																	
283	**COG & LDAC**		$2.15	$4.49	$6.24	$7.78	$7.08	$4.45	$32.19	$2.30	$0.95	$0.50	$0.43	$0.42	$0.77	$5.37	$37.56
284	% Change		2.55%	2.55%	2.55%	2.08%	2.08%	2.08%	2.24%	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%	2.43%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
285	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
286	**Commercial/Industrial - Medium Annual Use, High Winter Use (G-42)**																
287	**PROPOSED**																
288			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
289	**average Usage (Therms)**		940	1,649	2,259	2,699	2,446	1,639	11,632	1,001	491	269	267	264	437	2,729	14,362
290																	
291	**Winter:**																
292	Cust. Chg	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00								
293	Headblock	$0.4283	$402.75	$428.34	$428.34	$428.34	$428.34	$428.34	$2,544.44								
294	Tailblock	$0.2853	$0.00	$185.06	$359.26	$484.90	$412.63	$182.22	$1,624.06								
295	HB Threshold	1,000															
296																	
297	**Summer:**																
298	Cust. Chg	$172.33								$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00	$2,068.00
299	Headblock	$0.4283								$171.34	$171.34	$115.22	$114.42	$113.10	$171.34	$856.75	$3,401.19
300	Tailblock	$0.2853								$171.47	$25.99	$0.00	$0.00	$0.00	$10.55	$208.01	$1,832.08
301	HB Threshold	400															
302																	
303	Total Base Rate Amount		$575.09	$785.73	$959.93	$1,085.57	$1,013.30	$782.89	$5,202.50	$515.13	$369.66	$287.55	$286.75	$285.43	$354.22	$2,098.76	$7,301.26
304																	
305	COG Rate - (Winter)		$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7371								
306	COG amount - Winter		$604.88	$1,060.55	$1,453.31	$2,170.65	$1,966.98	$1,317.63	$8,573.99								
307																	
308	COG Rate - (Summer)									$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.6556
309	COG amount - Summer									$308.70	$151.46	$82.96	$82.38	$81.43	$134.77	$841.69	$9,415.68
310																	
311	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
312	LDAC amount		$80.39	$140.96	$193.16	$230.81	$209.15	$140.10	$994.57	$85.58	$41.99	$23.00	$22.84	$22.58	$37.36	$233.35	$1,227.92
313																	
314	**Total Bill**		**$1,260.36**	**$1,987.23**	**$2,606.39**	**$3,487.03**	**$3,189.42**	**$2,240.62**	**$14,771.06**	**$909.41**	**$563.11**	**$393.51**	**$391.98**	**$389.44**	**$526.35**	**$3,173.80**	**$17,944.86**
315																	
316	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
317	**Commercial/Industrial - Medium Annual Use, High Winter Use (G-42)**																
318	**CURRENT**																
319			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
320	**average Usage (Therms)**		940	1,649	2,259	2,699	2,446	1,639	11,632	1,001	491	269	267	264	437	2,729	14,362
321																	
322	**Winter:**																
323	Cust. Chg	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
324	Headblock	$0.3986	$374.79	$398.60	$398.60	$398.60	$398.60	$398.60	$2,367.79								
325	Tailblock	$0.2655	$0.00	$172.20	$334.30	$451.21	$383.96	$169.56	$1,511.24								
326	HB Threshold	1,000															
327																	
328	**Summer:**																
329	Cust. Chg	$160.36								$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16	$1,924.32
330	Headblock	$0.3986								$159.44	$159.44	$107.22	$106.48	$105.25	$159.44	$797.27	$3,165.06
331	Tailblock	$0.2655								$159.55	$24.19	$0.00	$0.00	$0.00	$9.82	$193.56	$1,704.80
332	HB Threshold	400															
333																	
334	Total Base Rate Amount		$535.15	$731.16	$893.26	$1,010.17	$942.92	$728.52	$4,841.19	$479.35	$343.99	$267.58	$266.84	$265.61	$329.62	$1,952.99	$6,794.18
335																	
336	COG Rate - (Winter)		$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7371								
337	COG amount - Winter		$604.88	$1,060.55	$1,453.31	$2,170.65	$1,966.98	$1,317.63	$8,573.99								
338																	
339	COG Rate - (Summer)									$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.6556
340	COG amount - Summer									$308.70	$151.46	$82.96	$82.38	$81.43	$134.77	$841.69	$9,415.68
341																	
342	LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
343	LDAC amount		$63.37	$111.12	$152.27	$181.95	$164.87	$110.44	$784.02	$67.46	$33.10	$18.13	$18.00	$17.80	$29.45	$183.95	$967.97
344																	
345	**Total Bill**		**$1,203.40**	**$1,902.83**	**$2,498.83**	**$3,362.77**	**$3,074.77**	**$2,156.59**	**$14,199.20**	**$855.51**	**$528.54**	**$368.67**	**$367.22**	**$364.84**	**$493.84**	**$2,978.63**	**$17,177.83**
346																	
347	**DIFFERENCE:**																
348	**Total Bill**		**$56.95**	**$84.41**	**$107.56**	**$124.26**	**$114.65**	**$84.03**	**$571.86**	**$53.90**	**$34.56**	**$24.84**	**$24.75**	**$24.60**	**$32.51**	**$195.17**	**$767.03**
349	% Change		**4.73%**	**4.44%**	**4.30%**	**3.70%**	**3.73%**	**3.90%**	**4.03%**	**6.30%**	**6.54%**	**6.74%**	**6.74%**	**6.74%**	**6.58%**	**6.55%**	**4.47%**
350																	
351	**Base Rate**		$39.93	$54.57	$66.67	$75.40	$70.38	$54.37	$361.31	$35.78	$25.67	$19.97	$19.92	$19.83	$24.60	$145.77	$507.08
352	% Change		7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%
353																	
354	**COG & LDAC**		$17.02	$29.84	$40.89	$48.86	$44.28	$29.66	$210.55	$18.12	$8.89	$4.87	$4.84	$4.78	$7.91	$49.40	$259.95
355	% Change		2.55%	2.55%	2.55%	2.08%	2.08%	2.08%	2.25%	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%	2.50%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Winter Season (Jan. - Apr., Nov. - Dec.) / **Summer Season (May - Oct.)**

Commercial/Industrial - High Annual Use, High Winter Use (G-43)

PROPOSED

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		6,416	10,639	17,250	12,674	15,438	8,821	71,237	6,834	2,784	1,051	2,379	1,365	1,638	16,052	87,288
Winter:																
Cust. Chg	$739.57	$739.57	$739.57	$739.57	$739.57	$739.57	$739.57	$4,437.40								
Headblock	$0.2632	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.2632	$1,688.76	$2,800.47	$4,540.59	$3,336.05	$4,063.64	$2,321.94	$18,751.44								
HB Threshold	-															
Summer:																
Cust. Chg	$739.57								$739.57	$739.57	$739.57	$739.57	$739.57	$739.57	$4,437.40	$8,874.79
Headblock	$0.1203								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.1203								$822.36	$335.01	$126.50	$286.24	$164.26	$197.11	$1,931.48	$20,682.93
HB Threshold	-															
Total Base Rate Amount		$2,428.32	$3,540.04	$5,280.15	$4,075.62	$4,803.20	$3,061.51	$23,188.84	$1,561.92	$1,074.58	$866.07	$1,025.81	$903.83	$936.68	$6,368.88	$29,557.72
COG Rate - (Winter)		$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7267								
COG amount - Winter		$4,127.15	$6,844.06	$11,096.72	$10,190.88	$12,413.50	$7,093.02	$51,765.33								
COG Rate - (Summer)									$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.6498
COG amount - Summer									$2,107.68	$858.63	$324.21	$733.64	$420.99	$505.20	$4,950.34	$56,715.67
LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
LDAC amount		$548.54	$909.64	$1,474.86	$1,083.60	$1,319.94	$754.21	$6,090.78	$584.33	$238.04	$89.88	$203.39	$116.72	$140.06	$1,372.43	$7,463.21
Total Bill		**$7,104.01**	**$11,293.73**	**$17,851.73**	**$15,350.10**	**$18,536.64**	**$10,908.73**	**$81,044.95**	**$4,253.93**	**$2,171.25**	**$1,280.16**	**$1,962.84**	**$1,441.54**	**$1,581.93**	**$12,691.65**	**$93,736.60**

Winter Season (Jan. - Apr., Nov. - Dec.) / **Summer Season (May - Oct.)**

Commercial/Industrial - High Annual Use, High Winter Use (G-43)

CURRENT

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		6,416	10,639	17,250	12,674	15,438	8,821	71,237	6,834	2,784	1,051	2,379	1,365	1,638	16,052	87,288
Winter:																
Cust. Chg	$688.20	$688.20	$688.20	$688.20	$688.20	$688.20	$688.20	$4,129.20								
Headblock	$0.2449	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.2449	$1,571.18	$2,605.49	$4,224.45	$3,103.78	$3,780.71	$2,160.28	$17,445.88								
HB Threshold	-															
Summer:																
Cust. Chg	$688.20								$688.20	$688.20	$688.20	$688.20	$688.20	$688.20	$4,129.20	$8,258.40
Headblock	$0.1120								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.1120								$765.43	$311.82	$117.74	$266.43	$152.89	$183.47	$1,797.79	$19,243.67
HB Threshold	-															
Total Base Rate Amount		$2,259.38	$3,293.69	$4,912.65	$3,791.98	$4,468.91	$2,848.48	$21,575.08	$1,453.63	$1,000.02	$805.94	$954.63	$841.09	$871.67	$5,926.99	$27,502.07
COG Rate - (Winter)		$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7267								
COG amount - Winter		$4,127.15	$6,844.06	$11,096.72	$10,190.88	$12,413.50	$7,093.02	$51,765.33								
COG Rate - (Summer)									$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.3084	$0.6498
COG amount - Summer									$2,107.68	$858.63	$324.21	$733.64	$420.99	$505.20	$4,950.34	$56,715.67
LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
LDAC amount		$432.41	$717.07	$1,162.63	$854.20	$1,040.50	$594.54	$4,801.36	$460.63	$187.65	$70.86	$160.33	$92.01	$110.41	$1,081.88	$5,883.24
Total Bill		**$6,818.94**	**$10,854.81**	**$17,172.00**	**$14,837.07**	**$17,922.91**	**$10,536.03**	**$78,141.76**	**$4,021.94**	**$2,046.30**	**$1,201.01**	**$1,848.60**	**$1,354.09**	**$1,487.27**	**$11,959.22**	**$90,100.98**

DIFFERENCE:

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill		**$285.07**	**$438.92**	**$679.73**	**$513.04**	**$613.73**	**$372.70**	**$2,903.18**	**$231.99**	**$124.95**	**$79.15**	**$114.24**	**$87.44**	**$94.66**	**$732.44**	**$3,635.62**
% Change		**4.18%**	**4.04%**	**3.96%**	**3.46%**	**3.42%**	**3.54%**	**3.72%**	**5.77%**	**6.11%**	**6.59%**	**6.18%**	**6.46%**	**6.36%**	**6.12%**	**4.04%**
Base Rate		$168.95	$246.35	$367.50	$283.64	$334.30	$213.03	$1,613.76	$108.29	$74.56	$60.12	$71.18	$62.74	$65.01	$441.89	$2,055.65
% Change		7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.45%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.47%
COG & LDAC		$116.13	$192.57	$312.23	$229.40	$279.43	$159.67	$1,289.42	$123.70	$50.39	$19.03	$43.06	$24.71	$29.65	$290.54	$1,579.97
% Change		2.55%	2.55%	2.55%	2.08%	2.08%	2.08%	2.28%	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%	2.52%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No																	
427	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
428	**Commercial/Industrial - Low Annual Use, Low Winter Use (G-51)**																
429	**PROPOSED**																**Total**
430			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
431	**average Usage (Therms)**		174	237	290	343	331	246	1,621	186	151	125	119	119	134	834	2,455
432																	
433	**Winter:**																
434	Cust. Chg	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67								
435	Headblock	$0.2839	$28.39	$28.39	$28.39	$28.39	$28.39	$28.39	$170.34								
436	Tailblock	$0.1845	$13.63	$25.25	$34.97	$44.86	$42.59	$27.03	$188.32								
437	HB Threshold	100															
438																	
439	**Summer:**																
440	Cust. Chg	$57.44								$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67	$689.33
441	Headblock	$0.2839								$28.39	$28.39	$28.39	$28.39	$28.39	$28.39	$170.34	$340.67
442	Tailblock	$0.1845								$15.81	$9.43	$4.65	$3.58	$3.51	$6.20	$43.19	$231.51
443	HB Threshold	100															
444																	
445	Total Base Rate Amount		$99.47	$111.08	$120.81	$130.69	$128.42	$112.86	$703.32	$101.65	$95.27	$90.48	$89.41	$89.35	$92.03	$558.19	$1,261.51
446																	
447	COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7485								
448	COG amount - Winter		$114.08	$155.38	$189.96	$280.39	$271.30	$202.13	$1,213.24								
449																	
450	COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.6063
451	COG amount - Summer									$61.27	$49.86	$41.30	$39.39	$39.28	$44.08	$275.18	$1,488.42
452																	
453	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
454	LDAC amount		$14.87	$20.25	$24.76	$29.34	$28.29	$21.08	$138.58	$15.88	$12.92	$10.70	$10.21	$10.18	$11.42	$71.32	$209.90
455																	
456	**Total Bill**		**$228.42**	**$286.71**	**$335.53**	**$440.42**	**$428.01**	**$336.06**	**$2,055.14**	**$178.80**	**$158.05**	**$142.49**	**$139.02**	**$138.80**	**$147.53**	**$904.69**	**$2,959.83**
457																	
458	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
459	**Commercial/Industrial - Low Annual Use, Low Winter Use (G-51)**																
460	**CURRENT**																**Total**
461			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
462	**average Usage (Therms)**		174	237	290	343	331	246	1,621	186	151	125	119	119	134	834	2,455
463																	
464	**Winter:**																
465	Cust. Chg	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70								
466	Headblock	$0.2642	$26.42	$26.42	$26.42	$26.42	$26.42	$26.42	$158.52								
467	Tailblock	$0.1717	$12.69	$23.50	$32.55	$41.75	$39.64	$25.15	$175.28								
468	HB Threshold	100															
469																	
470	**Summer:**																
471	Cust. Chg	$53.45								$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70	$641.40
472	Headblock	$0.2642								$26.42	$26.42	$26.42	$26.42	$26.42	$26.42	$158.52	$317.04
473	Tailblock	$0.1717								$14.72	$8.78	$4.33	$3.33	$3.27	$5.77	$40.20	$215.48
474	HB Threshold	100															
475																	
476	Total Base Rate Amount		$92.56	$103.37	$112.42	$121.62	$119.51	$105.02	$654.50	$94.59	$88.65	$84.20	$83.20	$83.14	$85.64	$519.42	$1,173.92
477																	
478	COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7485								
479	COG amount - Winter		$114.08	$155.38	$189.96	$280.39	$271.30	$202.13	$1,213.24								
480																	
481	COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.6063
482	COG amount - Summer									$61.27	$49.86	$41.30	$39.39	$39.28	$44.08	$275.18	$1,488.42
483																	
484	LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
485	LDAC amount		$11.72	$15.96	$19.52	$23.13	$22.30	$16.61	$109.24	$12.52	$10.19	$8.44	$8.05	$8.02	$9.00	$56.22	$165.47
486																	
487	**Total Bill**		**$218.36**	**$274.71**	**$321.90**	**$425.14**	**$413.11**	**$323.77**	**$1,976.98**	**$168.38**	**$148.70**	**$133.94**	**$130.65**	**$130.44**	**$138.72**	**$850.82**	**$2,827.80**
488																	
489	**DIFFERENCE:**																
490	**Total Bill**		**$10.06**	**$12.00**	**$13.63**	**$15.28**	**$14.90**	**$12.30**	**$78.16**	**$10.42**	**$9.35**	**$8.55**	**$8.37**	**$8.36**	**$8.81**	**$53.87**	**$132.03**
491	% Change		**4.61%**	**4.37%**	**4.23%**	**3.59%**	**3.61%**	**3.80%**	**3.95%**	**6.19%**	**6.29%**	**6.38%**	**6.41%**	**6.41%**	**6.35%**	**6.33%**	**4.67%**
492																	
493	**Base Rate**		$6.91	$7.71	$8.39	$9.07	$8.91	$7.84	$48.82	$7.06	$6.62	$6.29	$6.21	$6.21	$6.39	$38.77	$87.60
494	% Change		7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.47%	7.47%	7.47%	7.47%	7.46%	7.46%
495																	
496	**COG & LDAC**		$3.15	$4.29	$5.24	$6.21	$5.99	$4.46	$29.34	$3.36	$2.74	$2.27	$2.16	$2.15	$2.42	$15.10	$44.44
497	% Change		2.50%	2.50%	2.50%	2.05%	2.04%	2.04%	2.22%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	2.69%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Winter Season (Jan. - Apr., Nov. - Dec.) / **Summer Season (May - Oct.)**
Commercial/Industrial - Medium Annual Use, Low Winter Use (G-52)

PROPOSED		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		1,158	1,463	1,820	1,382	1,954	1,515	9,292	1,188	953	818	759	782	898	5,398	14,690
Winter:																
Cust. Chg	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00								
Headblock	$0.2437	$243.75	$243.75	$243.75	$243.75	$243.75	$243.75	$1,462.48								
Tailblock	$0.1624	$25.60	$75.18	$133.11	$62.10	$154.89	$83.59	$534.48								
HB Threshold	1,000															
Summer:																
Cust. Chg	$172.33								$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00	$2,068.00
Headblock	$0.1766								$176.63	$168.38	$144.43	$134.15	$138.16	$158.58	$920.32	$2,382.80
Tailblock	$0.1004								$18.83	$0.00	$0.00	$0.00	$0.00	$0.00	$18.83	$553.31
HB Threshold	1,000															
Total Base Rate Amount		$441.68	$491.26	$549.19	$478.18	$570.97	$499.67	$3,030.95	$367.80	$340.71	$316.76	$306.48	$310.49	$330.91	$1,973.15	$5,004.10
COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7412								
COG amount - Winter		$759.43	$959.72	$1,193.77	$1,129.58	$1,602.20	$1,242.11	$6,886.82								
COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.5901
COG amount - Summer									$391.79	$314.48	$269.75	$250.54	$258.04	$296.18	$1,780.79	$8,667.61
LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
LDAC amount		$98.98	$125.09	$155.59	$118.20	$167.06	$129.51	$794.43	$101.54	$81.51	$69.91	$64.93	$66.88	$76.76	$461.53	$1,255.96
Total Bill		**$1,300.10**	**$1,576.07**	**$1,898.56**	**$1,725.96**	**$2,340.23**	**$1,871.30**	**$10,712.21**	**$861.13**	**$736.70**	**$656.43**	**$621.96**	**$635.41**	**$703.85**	**$4,215.47**	**$14,927.68**

Winter Season (Jan. - Apr., Nov. - Dec.) / **Summer Season (May - Oct.)**
Commercial/Industrial - Medium Annual Use, Low Winter Use (G-52)

CURRENT		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		1,158	1,463	1,820	1,382	1,954	1,515	9,292	1,188	953	818	759	782	898	5,398	14,690
Winter:																
Cust. Chg	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
Headblock	$0.2268	$226.80	$226.80	$226.80	$226.80	$226.80	$226.80	$1,360.80								
Tailblock	$0.1511	$23.82	$69.96	$123.87	$57.78	$144.13	$77.78	$497.35								
HB Threshold	1,000															
Summer:																
Cust. Chg	$160.36								$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16	$1,924.32
Headblock	$0.1644								$164.40	$156.72	$134.43	$124.85	$128.59	$147.60	$856.58	$2,217.38
Tailblock	$0.0934								$17.52	$0.00	$0.00	$0.00	$0.00	$0.00	$17.52	$514.87
HB Threshold	1,000															
Total Base Rate Amount		$410.98	$457.12	$511.03	$444.94	$531.29	$464.94	$2,820.31	$342.28	$317.08	$294.79	$285.21	$288.95	$307.96	$1,836.27	$4,656.58
COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7412								
COG amount - Winter		$759.43	$959.72	$1,193.77	$1,129.58	$1,602.20	$1,242.11	$6,886.82								
COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.5901
COG amount - Summer									$391.79	$314.48	$269.75	$250.54	$258.04	$296.18	$1,780.79	$8,667.61
LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
LDAC amount		$78.03	$98.61	$122.65	$93.18	$131.69	$102.10	$626.25	$80.04	$64.25	$55.11	$51.19	$52.72	$60.51	$363.82	$990.07
Total Bill		**$1,248.45**	**$1,515.45**	**$1,827.45**	**$1,667.70**	**$2,265.18**	**$1,809.15**	**$10,333.38**	**$814.12**	**$695.81**	**$619.65**	**$586.95**	**$599.71**	**$664.64**	**$3,980.88**	**$14,314.27**

DIFFERENCE:

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill	**$51.65**	**$60.62**	**$71.10**	**$58.26**	**$75.04**	**$62.14**	**$378.82**	**$47.01**	**$40.89**	**$36.78**	**$35.01**	**$35.70**	**$39.21**	**$234.59**	**$613.41**
% Change	**4.14%**	**4.00%**	**3.89%**	**3.49%**	**3.31%**	**3.43%**	**3.67%**	**5.77%**	**5.88%**	**5.93%**	**5.96%**	**5.95%**	**5.90%**	**5.89%**	**4.29%**
Base Rate	$30.70	$34.14	$38.17	$33.23	$39.68	$34.73	$210.64	$25.51	$23.63	$21.98	$21.26	$21.54	$22.96	$136.88	$347.53
% Change	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.45%	7.45%	7.45%	7.46%	7.46%	7.45%	7.45%	7.46%
COG & LDAC	$20.95	$26.48	$32.94	$25.02	$35.37	$27.42	$168.18	$21.50	$17.25	$14.80	$13.75	$14.16	$16.25	$97.71	$265.89
% Change	2.50%	2.50%	2.50%	2.05%	2.04%	2.04%	2.24%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	2.75%

Line No

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Winter Season (Jan. - Apr., Nov. - Dec.) | **Summer Season (May - Oct.)**

Commercial/Industrial - High Annual Use, Load Factor Less Than 90% (G-53)

PROPOSED		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		6,008	7,795	10,754	11,944	8,606	19,165	64,272	6,115	4,271	3,375	2,386	3,068	3,979	23,193	87,465
Winter:																
Cust. Chg	$761.10	$761.10	$761.10	$761.10	$761.10	$761.10	$761.10	$4,566.61								
Headblock	$0.1703	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.1703	$1,023.32	$1,327.73	$1,831.88	$2,034.56	$1,465.90	$3,264.51	$10,947.89								
HB Threshold	-															
Summer:																
Cust. Chg	$761.10								$761.10	$761.10	$761.10	$761.10	$761.10	$761.10	$4,566.61	$9,133.22
Headblock	$0.0817								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.0817								$499.71	$349.01	$275.79	$194.99	$250.69	$325.21	$1,895.40	$12,843.30
HB Threshold	-															
Total Base Rate Amount		$1,784.42	$2,088.83	$2,592.98	$2,795.66	$2,227.00	$4,025.61	$15,514.51	$1,260.82	$1,110.11	$1,036.89	$956.09	$1,011.79	$1,086.31	$6,462.01	$21,976.52
COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7568								
COG amount - Winter		$3,940.99	$5,113.32	$7,054.90	$9,759.69	$7,056.78	$15,715.27	$48,640.95								
COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.6436
COG amount - Summer									$2,017.22	$1,408.88	$1,113.28	$787.13	$1,011.98	$1,312.80	$7,651.29	$56,292.24
LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
LDAC amount		$513.65	$666.45	$919.51	$1,021.24	$735.80	$1,638.61	$5,495.27	$522.81	$365.14	$288.53	$204.00	$262.28	$340.24	$1,982.99	$7,478.27
Total Bill		**$6,239.06**	**$7,868.60**	**$10,567.39**	**$13,576.59**	**$10,019.58**	**$21,379.50**	**$69,650.73**	**$3,800.85**	**$2,884.14**	**$2,438.70**	**$1,947.22**	**$2,286.05**	**$2,739.35**	**$16,096.30**	**$85,747.02**

Winter Season (Jan. - Apr., Nov. - Dec.) | **Summer Season (May - Oct.)**

Commercial/Industrial - High Annual Use, Load Factor Less Than 90% (G-53)

CURRENT		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		6,008	7,795	10,754	11,944	8,606	19,165	64,272	6,115	4,271	3,375	2,386	3,068	3,979	23,193	87,465
Winter:																
Cust. Chg	$708.24	$708.24	$708.24	$708.24	$708.24	$708.24	$708.24	$4,249.44								
Headblock	$0.1585	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.1585	$952.20	$1,235.46	$1,704.58	$1,893.17	$1,364.02	$3,037.65	$10,187.08								
HB Threshold	-															
Summer:																
Cust. Chg	$708.24								$708.24	$708.24	$708.24	$708.24	$708.24	$708.24	$4,249.44	$8,498.88
Headblock	$0.0760								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.0760								$464.71	$324.57	$256.47	$181.33	$233.13	$302.43	$1,762.65	$11,949.73
HB Threshold	-															
Total Base Rate Amount		$1,660.44	$1,943.70	$2,412.82	$2,601.41	$2,072.26	$3,745.89	$14,436.52	$1,172.95	$1,032.81	$964.71	$889.57	$941.37	$1,010.67	$6,012.09	$20,448.61
COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7568								
COG amount - Winter		$3,940.99	$5,113.32	$7,054.90	$9,759.69	$7,056.78	$15,715.27	$48,640.95								
COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.6436
COG amount - Summer									$2,017.22	$1,408.88	$1,113.28	$787.13	$1,011.98	$1,312.80	$7,651.29	$56,292.24
LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
LDAC amount		$404.91	$525.36	$724.85	$805.05	$580.03	$1,291.72	$4,331.92	$412.13	$287.84	$227.45	$160.81	$206.75	$268.21	$1,563.19	$5,895.11
Total Bill		**$6,006.34**	**$7,582.38**	**$10,192.56**	**$13,166.14**	**$9,709.08**	**$20,752.88**	**$67,409.39**	**$3,602.31**	**$2,729.53**	**$2,305.44**	**$1,837.51**	**$2,160.11**	**$2,591.68**	**$15,226.57**	**$82,635.96**

DIFFERENCE:

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill		**$232.72**	**$286.22**	**$374.83**	**$410.45**	**$310.50**	**$626.62**	**$2,241.34**	**$198.54**	**$154.61**	**$133.26**	**$109.71**	**$125.94**	**$147.67**	**$869.73**	**$3,111.06**
% Change		**3.87%**	**3.77%**	**3.68%**	**3.12%**	**3.20%**	**3.02%**	**3.32%**	**5.51%**	**5.66%**	**5.78%**	**5.97%**	**5.83%**	**5.70%**	**5.71%**	**3.76%**
Base Rate		$123.98	$145.13	$180.17	$194.25	$154.73	$279.73	$1,077.98	$87.86	$77.31	$72.18	$66.52	$70.42	$75.64	$449.92	$1,527.91
% Change		7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.49%	7.49%	7.48%	7.48%	7.48%	7.48%	7.48%	7.47%
COG & LDAC		$108.74	$141.09	$194.66	$216.20	$155.77	$346.90	$1,163.35	$110.68	$77.30	$61.08	$43.19	$55.52	$72.03	$419.80	$1,583.15
% Change		2.50%	2.50%	2.50%	2.05%	2.04%	2.04%	2.20%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	2.55%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
640	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
641	**Commercial/Industrial - High Annual Use, Load Factor Greater Than 90% (G-54)**																
642	**PROPOSED**																
643			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
644	**average Usage (Therms)**		11,937	12,313	28,452	31,015	31,889	33,999	149,606	23,395	12,360	7,196	9,964	10,085	14,348	77,349	226,955
645																	
646	**Winter:**																
647	Cust. Chg	$761.10	$761.10	$761.10	$761.10	$761.10	$761.10	$761.10	$4,566.61								
648	Headblock	$0.0650	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
649	Tailblock	$0.0650	$775.61	$800.06	$1,848.71	$2,015.20	$2,072.00	$2,209.12	$9,720.71								
650	HB Threshold	-															
651																	
652	**Summer:**																
653	Cust. Chg	$761.10								$761.10	$761.10	$761.10	$761.10	$761.10	$761.10	$4,566.61	$9,133.22
654	Headblock	$0.0353								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
655	Tailblock	$0.0353								$825.35	$436.07	$253.87	$351.52	$355.80	$506.18	$2,728.79	$12,449.50
656	HB Threshold	-															
657																	
658	Total Base Rate Amount		$1,536.72	$1,561.16	$2,609.81	$2,776.30	$2,833.10	$2,970.22	$14,287.32	$1,586.46	$1,197.17	$1,014.97	$1,112.62	$1,116.90	$1,267.28	$7,295.40	$21,582.72
659																	
660	COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7616								
661	COG amount - Winter		$7,830.72	$8,077.52	$18,664.84	$25,342.26	$26,149.04	$27,879.53	$113,943.89								
662																	
663	COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.6145
664	COG amount - Summer									$7,718.02	$4,077.72	$2,373.98	$3,287.12	$3,327.14	$4,733.34	$25,517.30	$139,461.19
665																	
666	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
667	LDAC amount		$1,020.63	$1,052.79	$2,432.70	$2,651.79	$2,726.53	$2,906.97	$12,791.41	$2,000.29	$1,056.83	$615.27	$851.93	$862.30	$1,226.74	$6,613.34	$19,404.75
668																	
669	**Total Bill**		**$10,388.06**	**$10,691.47**	**$23,707.35**	**$30,770.35**	**$31,708.67**	**$33,756.72**	**$141,022.62**	**$11,304.76**	**$6,331.71**	**$4,004.21**	**$5,251.66**	**$5,306.34**	**$7,227.36**	**$39,426.04**	**$180,448.66**
670																	
671	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
672	**Commercial/Industrial - High Annual Use, Load Factor Greater Than 90% (G-54)**																
673	**CURRENT**																
674			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
675	**average Usage (Therms)**		11,937	12,313	28,452	31,015	31,889	33,999	149,606	23,395	12,360	7,196	9,964	10,085	14,348	77,349	226,955
676																	
677	**Winter:**																
678	Cust. Chg	$708.24	$708.24	$708.24	$708.24	$708.24	$708.24	$708.24	$4,249.44								
679	Headblock	$0.0605	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
680	Tailblock	$0.0605	$722.19	$744.95	$1,721.38	$1,876.40	$1,929.29	$2,056.97	$9,051.18								
681	HB Threshold	-															
682																	
683	**Summer:**																
684	Cust. Chg	$708.24								$708.24	$708.24	$708.24	$708.24	$708.24	$708.24	$4,249.44	$8,498.88
685	Headblock	$0.0328								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
686	Tailblock	$0.0328								$767.36	$405.42	$236.03	$326.82	$330.80	$470.61	$2,537.03	$11,588.21
687	HB Threshold	-															
688																	
689	Total Base Rate Amount		$1,430.43	$1,453.19	$2,429.62	$2,584.64	$2,637.53	$2,765.21	$13,300.62	$1,475.60	$1,113.66	$944.27	$1,035.06	$1,039.04	$1,178.85	$6,786.47	$20,087.09
690																	
691	COG Rate - (Winter)		$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7616								
692	COG amount - Winter		$7,830.72	$8,077.52	$18,664.84	$25,342.26	$26,149.04	$27,879.53	$113,943.89								
693																	
694	COG Rate - (Summer)									$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.3299	$0.6145
695	COG amount - Summer									$7,718.02	$4,077.72	$2,373.98	$3,287.12	$3,327.14	$4,733.34	$25,517.30	$139,461.19
696																	
697	LDAC	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674
698	LDAC amount		$804.56	$829.92	$1,917.70	$2,090.40	$2,149.32	$2,291.56	$10,083.46	$1,576.82	$833.10	$485.01	$671.57	$679.75	$967.04	$5,213.30	$15,296.75
699																	
700	**Total Bill**		**$10,065.71**	**$10,360.63**	**$23,012.15**	**$30,017.30**	**$30,935.89**	**$32,936.29**	**$137,327.97**	**$10,770.44**	**$6,024.48**	**$3,803.26**	**$4,993.75**	**$5,045.92**	**$6,879.23**	**$37,517.07**	**$174,845.04**
701																	
702	**DIFFERENCE:**																
703	**Total Bill**		**$322.35**	**$330.84**	**$695.20**	**$753.05**	**$772.78**	**$820.43**	**$3,694.65**	**$534.32**	**$307.24**	**$200.95**	**$257.92**	**$260.41**	**$348.13**	**$1,908.97**	**$5,603.63**
704	% Change		**3.20%**	**3.19%**	**3.02%**	**2.51%**	**2.50%**	**2.49%**	**2.69%**	**4.96%**	**5.10%**	**5.28%**	**5.16%**	**5.16%**	**5.06%**	**5.09%**	**3.20%**
705																	
706	**Base Rate**		$106.28	$107.97	$180.19	$191.66	$195.57	$205.02	$986.70	$110.86	$83.50	$70.70	$77.56	$77.86	$88.43	$508.92	$1,495.63
707	% Change		7.43%	7.43%	7.42%	7.42%	7.42%	7.41%	7.42%	7.51%	7.50%	7.49%	7.49%	7.49%	7.50%	7.50%	7.45%
708																	
709	**COG & LDAC**		$216.07	$222.88	$515.00	$561.39	$577.21	$615.41	$2,707.95	$423.46	$223.73	$130.25	$180.35	$182.55	$259.70	$1,400.05	$4,108.00
710	% Change		2.50%	2.50%	2.50%	2.05%	2.04%	2.04%	2.18%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	2.65%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Winter Season (Jan. - Apr., Nov. - Dec.) | **Summer Season (May - Oct.)**

Keene Residential to EnergyNorth Residential Non-Heating (R1)

PROPOSED		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		14	18	18	20	21	16	108	15	11	9	8	7	10	60	168
Winter:																
Cust. Chg	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28								
Headblock	$0.4200	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.4200	$6.04	$7.65	$7.48	$8.52	$8.73	$6.91	$45.35								
HB Threshold	-															
Summer:																
Cust. Chg	$14.88								$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28	$178.56
Headblock	$0.4200								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.4200								$6.32	$4.63	$3.68	$3.31	$2.95	$4.12	$25.00	$70.35
HB Threshold	-															
Total Base Rate Amount		$20.92	$22.53	$22.36	$23.40	$23.61	$21.79	$134.63	$21.20	$19.51	$18.56	$18.19	$17.83	$19.00	$114.28	$248.91
COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4281								
COG amount - Winter		$18.04	$22.84	$23.18	$31.80	$32.58	$25.77	$154.20								
COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.7007	$1.1696
COG amount - Summer									$9.46	$6.92	$6.02	$6.12	$5.51	$7.70	$41.72	$195.92
LDAC	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037
LDAC amount		$1.49	$1.89	$1.85	$2.10	$2.16	$1.71	$11.20	$1.56	$1.14	$0.91	$0.82	$0.73	$1.02	$6.17	$17.37
Total Bill		**$40.45**	**$47.26**	**$47.39**	**$57.31**	**$58.35**	**$49.26**	**$300.02**	**$32.22**	**$27.57**	**$25.48**	**$25.13**	**$24.06**	**$27.71**	**$162.17**	**$462.20**

Winter Season (Jan. - Apr., Nov. - Dec.) | **Summer Season (May - Oct.)**

Keene Residential to EnergyNorth Residential Non-Heating (R1)

CURRENT		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		14	18	18	20	21	16	108	15	11	9	8	7	10	60	168
Winter:																
Cust. Chg	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$54.00								
Block 1	$1.1522	$16.58	$21.00	$20.53	$23.39	$23.96	$18.95	$124.41								
Block 2	$0.9442	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Block 3	$0.7946	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
BL1 Threshold	80															
BL2 Threshold	120															
Summer:																
Cust. Chg	$9.00								$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$54.00	$108.00
Block 1	$1.1522								$17.35	$12.69	$10.09	$9.08	$8.08	$11.30	$68.59	$193.01
Block 2	$0.9442								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Block 3	$0.7946								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
BL1 Threshold	80															
BL2 Threshold	120															
Total Base Rate Amount		$25.58	$30.00	$29.53	$32.39	$32.96	$27.95	$178.41	$26.35	$21.69	$19.09	$18.08	$17.08	$20.30	$122.59	$301.01
COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4281								
COG amount - Winter		$18.04	$22.84	$23.18	$31.80	$32.58	$25.77	$154.20								
COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.7007	$1.1696
COG amount - Summer									$9.46	$6.92	$6.02	$6.12	$5.51	$7.70	$41.72	$195.92
LDAC	$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	$0.0000
LDAC amount		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Bill		**$43.62**	**$52.83**	**$52.71**	**$64.18**	**$65.54**	**$53.72**	**$332.61**	**$35.81**	**$28.61**	**$25.11**	**$24.20**	**$22.59**	**$27.99**	**$164.31**	**$496.92**

DIFFERENCE:

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill		**($3.17)**	**($5.57)**	**($5.32)**	**($6.88)**	**($7.19)**	**($4.46)**	**($32.59)**	**($3.58)**	**($1.04)**	**$0.37**	**$0.93**	**$1.47**	**($0.28)**	**($2.14)**	**($34.73)**
% Change		**-7.26%**	**-10.55%**	**-10.09%**	**-10.72%**	**-10.97%**	**-8.30%**	**-9.80%**	**-10.01%**	**-3.65%**	**1.49%**	**3.83%**	**6.51%**	**-1.01%**	**-1.30%**	**-6.99%**
Base Rate		($4.66)	($7.46)	($7.17)	($8.98)	($9.35)	($6.16)	($43.79)	($5.15)	($2.19)	($0.54)	$0.11	$0.74	($1.30)	($8.31)	($52.10)
% Change		-18.21%	-24.88%	-24.27%	-27.74%	-28.36%	-22.05%	-24.54%	-19.53%	-10.08%	-2.80%	0.61%	4.36%	-6.40%	-6.78%	-17.31%
COG & LDAC		$1.49	$1.89	$1.85	$2.10	$2.16	$1.71	$11.20	$1.56	$1.14	$0.91	$0.82	$0.73	$1.02	$6.17	$17.37
% Change		8.27%	8.27%	7.97%	6.62%	6.62%	6.62%	7.26%	16.51%	16.51%	15.10%	13.35%	13.21%	13.21%	14.80%	8.87%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
786	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
787	**Keene Residential to EnergyNorth Residential Heating (R3)**																
788	**PROPOSED**																
789			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
790	**average Usage (Therms)**		34	70	67	93	103	58	424	38	14	9	8	7	12	87	511
791																	
792	**Winter:**																
793	Cust. Chg	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28								
794	Headblock	$0.5775	$19.49	$40.19	$38.86	$53.75	$57.75	$33.52	$243.56								
795	Tailblock	$0.5775	$0.00	$0.00	$0.00	$0.00	$1.48	$0.00	$1.48								
796	HB Threshold	100															
797																	
798	**Summer:**																
799	Cust. Chg	$14.88								$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28	$178.56
800	Headblock	$0.5775								$11.55	$8.14	$5.15	$4.42	$3.81	$6.82	$39.89	$283.45
801	Tailblock	$0.5775								$10.42	$0.00	$0.00	$0.00	$0.00	$0.00	$10.42	$11.90
802	HB Threshold	20															
803																	
804	Total Base Rate Amount		$34.37	$55.07	$53.74	$68.63	$74.11	$48.40	$334.32	$36.85	$23.02	$20.03	$19.30	$18.69	$21.70	$139.59	$473.91
805																	
806	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4481								
807	COG amount - Winter		$42.31	$87.22	$87.54	$145.80	$160.67	$90.93	$614.46								
808																	
809	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.6803	$1.3173
810	COG amount - Summer									$23.90	$8.85	$6.12	$5.95	$5.18	$9.28	$59.27	$673.72
811																	
812	LDAC	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037	$0.1037
813	LDAC amount		$3.50	$7.22	$6.98	$9.65	$10.64	$6.02	$44.00	$3.95	$1.46	$0.92	$0.79	$0.68	$1.23	$9.03	$53.04
814																	
815	**Total Bill**		**$80.18**	**$149.50**	**$148.26**	**$224.08**	**$245.41**	**$145.34**	**$992.78**	**$64.69**	**$33.33**	**$27.07**	**$26.04**	**$24.55**	**$32.20**	**$207.89**	**$1,200.67**
816																	
817	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
818	**Keene Residential to EnergyNorth Residential Heating (R3)**																
819	**CURRENT**																
820			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
821	**average Usage (Therms)**		34	70	67	93	103	58	424	38	14	9	8	7	12	87	511
822																	
823	**Winter:**																
824	Cust. Chg	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$54.00								
825	Block 1	$1.1522	$38.89	$80.18	$77.54	$92.18	$92.18	$66.87	$447.84								
826	Block 2	$0.9442	$0.00	$0.00	$0.00	$12.34	$21.30	$0.00	$33.64								
827	Block 3	$0.7946	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
828	BL1 Threshold	80															
829	BL2 Threshold	120															
830																	
831	**Summer:**																
832	Cust. Chg	$9.00								$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$54.00	$108.00
833	Block 1	$1.1522								$43.83	$16.24	$10.27	$8.82	$7.60	$13.61	$100.37	$548.21
834	Block 2	$0.9442								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33.64
835	Block 3	$0.7946								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
836	BL1 Threshold	80															
837	BL2 Threshold	120															
838																	
839	Total Base Rate Amount		$47.89	$89.18	$86.54	$113.51	$122.48	$75.87	$535.48	$52.83	$25.24	$19.27	$17.82	$16.60	$22.61	$154.37	$689.85
840																	
841	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4481								
842	COG amount - Winter		$42.31	$87.22	$87.54	$145.80	$160.67	$90.93	$614.46								
843																	
844	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.6803	$1.3173
845	COG amount - Summer									$23.90	$8.85	$6.12	$5.95	$5.18	$9.28	$59.27	$673.72
846																	
847	LDAC	$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	$0.0000
848	LDAC amount		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
849																	
850	**Total Bill**		**$90.20**	**$176.40**	**$174.08**	**$259.31**	**$283.15**	**$166.80**	**$1,149.94**	**$76.73**	**$34.09**	**$25.38**	**$23.77**	**$21.77**	**$31.89**	**$213.64**	**$1,363.58**
851																	
852	**DIFFERENCE:**																
853	**Total Bill**		**($10.02)**	**($26.90)**	**($25.82)**	**($35.24)**	**($37.73)**	**($21.46)**	**($157.16)**	**($12.04)**	**($0.76)**	**$1.68**	**$2.27**	**$2.77**	**$0.31**	**($5.75)**	**($162.91)**
854	% Change		**-11.11%**	**-15.25%**	**-14.83%**	**-13.59%**	**-13.33%**	**-12.86%**	**-13.67%**	**-15.69%**	**-2.23%**	**6.63%**	**9.56%**	**12.74%**	**0.99%**	**-2.69%**	**-11.95%**
855																	
856	**Base Rate**		($13.52)	($34.11)	($32.79)	($44.89)	($48.37)	($27.48)	($201.16)	($15.98)	($2.22)	$0.76	$1.48	$2.09	($0.91)	($14.79)	($215.95)
857	% Change		-28.23%	-38.25%	-37.90%	-39.54%	-39.49%	-36.21%	-37.57%	-30.25%	-8.80%	3.94%	8.30%	12.60%	-4.03%	-9.58%	-31.30%
858																	
859	**COG & LDAC**		$3.50	$7.22	$6.98	$9.65	$10.64	$6.02	$44.00	$3.95	$1.46	$0.92	$0.79	$0.68	$1.23	$9.03	$53.04
860	% Change		8.27%	8.27%	7.97%	6.62%	6.62%	6.62%	7.16%	16.51%	16.51%	15.10%	13.35%	13.21%	13.21%	15.24%	7.87%

Line No

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Winter Season (Jan. - Apr., Nov. - Dec.) | **Summer Season (May - Oct.)**

Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Low Annual Use, High Winter Use (G-41)

PROPOSED		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		64	120	158	251	245	132	970	91	28	14	10	9	20	173	1,143
Winter:																
Cust. Chg	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67								
Headblock	$0.4710	$29.98	$47.10	$47.10	$47.10	$47.10	$47.10	$265.47								
Tailblock	$0.3163	$0.00	$6.42	$18.40	$47.73	$45.93	$9.99	$128.48								
HB Threshold	100															
Summer:																
Cust. Chg	$57.44								$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67	$689.33
Headblock	$0.4710								$9.42	$9.42	$6.78	$4.73	$4.32	$9.42	$44.08	$309.55
Tailblock	$0.3163								$22.36	$2.62	$0.00	$0.00	$0.00	$0.08	$25.06	$153.54
HB Threshold	20															
Total Base Rate Amount		$87.42	$110.96	$122.94	$152.28	$150.47	$114.54	$738.61	$89.22	$69.49	$64.22	$62.17	$61.76	$66.95	$413.81	$1,152.42
COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4638								
COG amount - Winter		$79.78	$150.76	$205.75	$393.07	$384.13	$206.15	$1,419.62								
COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.6683	$1.3435
COG amount - Summer									$56.95	$17.77	$9.88	$7.80	$7.20	$15.91	$115.51	$1,535.13
LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
LDAC amount		$5.44	$10.28	$13.52	$21.45	$20.96	$11.25	$82.92	$7.75	$2.42	$1.23	$0.86	$0.78	$1.73	$14.78	$97.70
Total Bill		**$172.64**	**$272.00**	**$342.21**	**$566.80**	**$555.56**	**$331.94**	**$2,241.16**	**$153.93**	**$89.68**	**$75.33**	**$70.83**	**$69.74**	**$84.59**	**$544.10**	**$2,785.25**

Winter Season (Jan. - Apr., Nov. - Dec.) | **Summer Season (May - Oct.)**

Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Low Annual Use, High Winter Use (G-41)

CURRENT		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
average Usage (Therms)		64	120	158	251	245	132	970	91	28	14	10	9	20	173	1,143
Winter:																
Cust. Chg	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00								
Block 1	$1.1522	$73.34	$92.18	$92.18	$92.18	$92.18	$92.18	$534.22								
Block 2	$0.9442	$0.00	$38.04	$73.81	$113.30	$113.30	$48.71	$387.17								
Block 3	$0.7946	$0.00	$0.00	$0.00	$40.45	$35.91	$0.00	$76.36								
BL1 Threshold	80															
BL2 Threshold	120															
Summer:																
Cust. Chg	$18.00								$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00	$216.00
Block 1	$1.1522								$92.18	$32.60	$16.58	$11.57	$10.56	$23.35	$186.84	$721.06
Block 2	$0.9442								$10.08	$0.00	$0.00	$0.00	$0.00	$0.00	$10.08	$397.25
Block 3	$0.7946								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$76.36
BL1 Threshold	80															
BL2 Threshold	120															
Total Base Rate Amount		$91.34	$148.22	$183.98	$263.93	$259.39	$158.89	$1,105.75	$120.26	$50.60	$34.58	$29.57	$28.56	$41.35	$304.92	$1,410.67
COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4638								
COG amount - Winter		$79.78	$150.76	$205.75	$393.07	$384.13	$206.15	$1,419.62								
COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.6683	$1.3435
COG amount - Summer									$56.95	$17.77	$9.88	$7.80	$7.20	$15.91	$115.51	$1,535.13
LDAC	$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	$0.0000
LDAC amount		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Bill		**$171.12**	**$298.97**	**$389.73**	**$657.00**	**$643.52**	**$365.04**	**$2,525.38**	**$177.21**	**$68.37**	**$44.46**	**$37.37**	**$35.76**	**$57.26**	**$420.42**	**$2,945.80**

DIFFERENCE:

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill		**$1.53**	**($26.97)**	**($47.52)**	**($90.20)**	**($87.96)**	**($33.10)**	**($284.22)**	**($23.28)**	**$21.31**	**$30.87**	**$33.46**	**$33.98**	**$27.33**	**$123.67**	**($160.55)**
% Change		**0.89%**	**-9.02%**	**-12.19%**	**-13.73%**	**-13.67%**	**-9.07%**	**-11.25%**	**-13.14%**	**31.16%**	**69.44%**	**89.55%**	**95.04%**	**47.73%**	**29.42%**	**-5.45%**
Base Rate		($3.92)	($37.26)	($61.04)	($111.65)	($108.92)	($44.35)	($367.14)	($31.04)	$18.89	$29.64	$32.60	$33.20	$25.60	$108.90	($258.24)
% Change		-4.29%	-25.14%	-33.18%	-42.30%	-41.99%	-27.91%	-33.20%	-25.81%	37.33%	85.72%	110.26%	116.24%	61.91%	35.71%	-18.31%
COG & LDAC		$5.44	$10.28	$13.52	$21.45	$20.96	$11.25	$82.92	$7.75	$2.42	$1.23	$0.86	$0.78	$1.73	$14.78	$97.70
% Change		6.82%	6.82%	6.57%	5.46%	5.46%	5.46%	5.84%	13.61%	13.61%	12.45%	11.01%	10.89%	10.89%	12.79%	6.36%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
936	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
937	**Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Medium Annual Use, High Winter Use (G-42)**																
938	**PROPOSED**																
939			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
940	**average Usage (Therms)**		1,086	1,629	2,089	2,903	2,860	1,797	12,363	1,432	746	754	43	377	621	3,971	16,334
941																	
942	**Winter:**																
943	Cust. Chg	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00								
944	Headblock	$0.4283	$428.34	$428.34	$428.34	$428.34	$428.34	$428.34	$2,570.03								
945	Tailblock	$0.2853	$24.50	$179.42	$310.61	$542.89	$530.64	$227.45	$1,815.51								
946	HB Threshold	1,000															
947																	
948	**Summer:**																
949	Cust. Chg	$172.33								$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00	$2,068.00
950	Headblock	$0.4283								$171.34	$171.34	$171.34	$18.24	$161.28	$171.34	$864.86	$3,434.89
951	Tailblock	$0.2853								$294.47	$98.71	$100.94	$0.00	$0.00	$62.92	$557.03	$2,372.54
952	HB Threshold	400															
953																	
954	Total Base Rate Amount		$625.18	$780.09	$911.28	$1,143.56	$1,131.31	$828.12	$5,419.54	$638.14	$442.37	$444.61	$190.57	$333.62	$406.59	$2,455.89	$7,875.43
955																	
956	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4529								
957	COG amount - Winter		$1,360.94	$2,041.42	$2,716.89	$4,547.42	$4,480.16	$2,815.43	$17,962.27								
958																	
959	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.6802	$1.2650
960	COG amount - Summer									$899.47	$468.53	$517.54	$33.07	$295.62	$487.17	$2,701.39	$20,663.66
961																	
962	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
963	LDAC amount		$92.84	$139.27	$178.58	$248.19	$244.51	$153.66	$1,057.05	$122.44	$63.78	$64.45	$3.64	$32.19	$53.05	$339.56	$1,396.60
964																	
965	**Total Bill**		**$2,078.96**	**$2,960.78**	**$3,806.74**	**$5,939.17**	**$5,855.99**	**$3,797.21**	**$24,438.85**	**$1,660.05**	**$974.68**	**$1,026.59**	**$227.28**	**$661.43**	**$946.81**	**$5,496.84**	**$29,935.69**
966																	

Line No			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
967	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
968	**Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Medium Annual Use, High Winter Use (G-42)**																
969	**CURRENT**																
970			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
971	**average Usage (Therms)**		1,086	1,629	2,089	2,903	2,860	1,797	12,363	1,432	746	754	43	377	621	3,971	16,334
972																	
973	**Winter:**																
974	Cust. Chg	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00								
975	Block 1	$1.1522	$92.18	$92.18	$92.18	$92.18	$92.18	$92.18	$553.06								
976	Block 2	$0.9442	$113.30	$113.30	$113.30	$113.30	$113.30	$113.30	$679.82								
977	Block 3	$0.7946	$703.92	$1,135.35	$1,500.70	$2,147.59	$2,113.48	$1,269.10	$8,870.15								
978	BL1 Threshold	80															
979	BL2 Threshold	120															
980																	
981	**Summer:**																
982	Cust. Chg	$18.00								$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00	$216.00
983	Block 1	$1.1522								$92.18	$92.18	$92.18	$49.06	$92.18	$92.18	$509.94	$1,063.00
984	Block 2	$0.9442								$113.30	$113.30	$113.30	$0.00	$113.30	$113.30	$566.52	$1,246.34
985	Block 3	$0.7946								$978.99	$433.81	$440.03	$0.00	$140.27	$334.14	$2,327.24	$11,197.39
986	BL1 Threshold	80															
987	BL2 Threshold	120															
988																	
989	Total Base Rate Amount		$927.40	$1,358.83	$1,724.18	$2,371.07	$2,336.96	$1,492.58	$10,211.03	$1,202.47	$657.29	$663.51	$67.06	$363.75	$557.62	$3,511.70	$13,722.74
990																	
991	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4529								
992	COG amount - Winter		$1,360.94	$2,041.42	$2,716.89	$4,547.42	$4,480.16	$2,815.43	$17,962.27								
993																	
994	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.6802	$1.2650
995	COG amount - Summer									$899.47	$468.53	$517.54	$33.07	$295.62	$487.17	$2,701.39	$20,663.66
996																	
997	LDAC	$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	$0.0000
998	LDAC amount		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
999																	
1000	**Total Bill**		**$2,288.34**	**$3,400.25**	**$4,441.07**	**$6,918.50**	**$6,817.12**	**$4,308.02**	**$28,173.30**	**$2,101.94**	**$1,125.81**	**$1,181.05**	**$100.13**	**$659.37**	**$1,044.79**	**$6,213.09**	**$34,386.39**
1001																	
1002	**DIFFERENCE:**																
1003	**Total Bill**		**($209.38)**	**($439.48)**	**($634.33)**	**($979.33)**	**($961.13)**	**($510.81)**	**($3,734.45)**	**($441.89)**	**($151.14)**	**($154.45)**	**$127.15**	**$2.06**	**($97.98)**	**($716.26)**	**($4,450.71)**
1004	% Change		**-9.15%**	**-12.92%**	**-14.28%**	**-14.16%**	**-14.10%**	**-11.86%**	**-13.26%**	**-21.02%**	**-13.42%**	**-13.08%**	**126.98%**	**0.31%**	**-9.38%**	**-11.53%**	**-12.94%**
1005																	
1006	**Base Rate**		($302.23)	($578.74)	($812.90)	($1,227.51)	($1,205.65)	($664.47)	($4,791.50)	($564.34)	($214.91)	($218.90)	$123.51	($30.14)	($151.04)	($1,055.81)	($5,847.31)
1007	% Change		-32.59%	-42.59%	-47.15%	-51.77%	-51.59%	-44.52%	-46.92%	-46.93%	-32.70%	-32.99%	184.17%	-8.28%	-27.09%	-30.07%	-42.61%
1008																	
1009	**COG & LDAC**		$92.84	$139.27	$178.58	$248.19	$244.51	$153.66	$1,057.05	$122.44	$63.78	$64.45	$3.64	$32.19	$53.05	$339.56	$1,396.60
1010	% Change		6.82%	6.82%	6.57%	5.46%	5.46%	5.46%	5.88%	13.61%	13.61%	12.45%	11.01%	10.89%	10.89%	12.57%	6.76%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
1011	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
1012	**Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Low Annual Use, Low Winter Use (G-51)**																
1013	**PROPOSED**																
1014			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
1015	**average Usage (Therms)**		143	101	140	178	179	138	878	137	109	97	98	90	105	635	1,513
1016																	
1017	**Winter:**																
1018	Cust. Chg	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67								
1019	Headblock	$0.2839	$28.39	$28.39	$28.39	$28.39	$28.39	$28.39	$170.34								
1020	Tailblock	$0.1845	$7.93	$0.22	$7.29	$14.32	$14.50	$7.08	$51.34								
1021	HB Threshold	100															
1022																	
1023	**Summer:**																
1024	Cust. Chg	$57.44								$57.44	$57.44	$57.44	$57.44	$57.44	$57.44	$344.67	$689.33
1025	Headblock	$0.2839								$28.39	$28.39	$27.53	$27.90	$25.54	$28.39	$166.13	$336.47
1026	Tailblock	$0.1845								$6.76	$1.63	$0.00	$0.00	$0.00	$0.83	$9.22	$60.56
1027	HB Threshold	100															
1028																	
1029	Total Base Rate Amount		$93.76	$86.06	$93.12	$100.15	$100.33	$92.92	$566.34	$92.59	$87.47	$84.97	$85.35	$82.98	$86.66	$520.02	$1,086.36
1030																	
1031	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4373								
1032	COG amount - Winter		$179.18	$126.85	$181.48	$278.23	$279.81	$216.82	$1,262.36								
1033																	
1034	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.7081	$1.1312
1035	COG amount - Summer									$85.81	$68.37	$66.57	$76.32	$70.63	$82.05	$449.75	$1,712.11
1036																	
1037	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
1038	LDAC amount		$12.22	$8.65	$11.93	$15.18	$15.27	$11.83	$75.09	$11.68	$9.31	$8.29	$8.40	$7.69	$8.94	$54.31	$129.40
1039																	
1040	**Total Bill**		**$285.16**	**$221.56**	**$286.53**	**$393.56**	**$395.41**	**$321.57**	**$1,903.80**	**$190.09**	**$165.14**	**$159.83**	**$170.07**	**$161.30**	**$177.65**	**$1,024.07**	**$2,927.87**
1041																	
1042	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
1043	**Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Low Annual Use, Low Winter Use (G-51)**																
1044	**CURRENT**																
1045			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**Total 2017/18**
1046	**average Usage (Therms)**		143	101	140	178	179	138	878	137	109	97	98	90	105	635	1,513
1047																	
1048	**Winter:**																
1049	Cust. Chg	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00								
1050	Block 1	$1.1522	$92.18	$92.18	$92.18	$92.18	$92.18	$92.18	$553.06								
1051	Block 2	$0.9442	$59.45	$20.03	$56.19	$92.15	$93.10	$55.14	$376.07								
1052	Block 3	$0.7946	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
1053	BL1 Threshold	80															
1054	BL2 Threshold	120															
1055																	
1056	**Summer:**																
1057	Cust. Chg	$18.00								$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00	$216.00
1058	Block 1	$1.1522								$92.18	$92.18	$92.18	$92.18	$92.18	$92.18	$553.06	$1,106.11
1059	Block 2	$0.9442								$53.46	$27.23	$16.01	$17.26	$9.41	$23.14	$146.51	$522.58
1060	Block 3	$0.7946								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1061	BL1 Threshold	80															
1062	BL2 Threshold	120															
1063																	
1064	Total Base Rate Amount		$169.63	$130.21	$166.37	$202.33	$203.28	$165.32	$1,037.13	$163.64	$137.41	$126.19	$127.44	$119.58	$133.31	$807.57	$1,844.70
1065																	
1066	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4373								
1067	COG amount - Winter		$179.18	$126.85	$181.48	$278.23	$279.81	$216.82	$1,262.36								
1068																	
1069	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.7081	$1.1312
1070	COG amount - Summer									$85.81	$68.37	$66.57	$76.32	$70.63	$82.05	$449.75	$1,712.11
1071																	
1072	LDAC	$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	$0.0000
1073	LDAC amount		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1074																	
1075	**Total Bill**		**$348.80**	**$257.06**	**$347.84**	**$480.56**	**$483.09**	**$382.14**	**$2,299.49**	**$249.45**	**$205.78**	**$192.75**	**$203.76**	**$190.21**	**$215.36**	**$1,257.31**	**$3,556.80**
1076																	
1077	**DIFFERENCE:**																
1078	**Total Bill**		**($63.64)**	**($35.50)**	**($61.32)**	**($87.00)**	**($87.67)**	**($60.57)**	**($395.69)**	**($59.37)**	**($40.64)**	**($32.93)**	**($33.69)**	**($28.91)**	**($37.71)**	**($233.24)**	**($628.93)**
1079	% Change		**-18.25%**	**-13.81%**	**-17.63%**	**-18.10%**	**-18.15%**	**-15.85%**	**-17.21%**	**-23.80%**	**-19.75%**	**-17.08%**	**-16.53%**	**-15.20%**	**-17.51%**	**-18.55%**	**-17.68%**
1080																	
1081	**Base Rate**		($75.87)	($44.15)	($73.24)	($102.18)	($102.95)	($72.40)	($470.79)	($71.05)	($49.95)	($41.22)	($42.09)	($36.60)	($46.65)	($287.55)	($758.34)
1082	% Change		-44.73%	-33.91%	-44.03%	-50.50%	-50.64%	-43.79%	-45.39%	-43.42%	-36.35%	-32.66%	-33.03%	-30.60%	-34.99%	-35.61%	-41.11%
1083																	
1084	**COG & LDAC**		$12.22	$8.65	$11.93	$15.18	$15.27	$11.83	$75.09	$11.68	$9.31	$8.29	$8.40	$7.69	$8.94	$54.31	$129.40
1085	% Change		6.82%	6.82%	6.57%	5.46%	5.46%	5.46%	5.95%	13.61%	13.61%	12.45%	11.01%	10.89%	10.89%	12.08%	7.56%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Bill Impact Analysis - Cost of Gas Filing Methodology

Line No																	
1086	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
1087	**Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Medium Annual Use, Low Winter Use (G-52)**																
1088	**PROPOSED**																**Total**
1089			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
1090	**average Usage (Therms)**		1,738	1,988	2,323	2,764	2,724	1,985	13,521	1,777	1,318	1,199	1,307	1,127	1,447	8,175	21,696
1091																	
1092	**Winter:**																
1093	Cust. Chg	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00								
1094	Headblock	$0.2437	$243.75	$243.75	$243.75	$243.75	$243.75	$243.75	$1,462.48								
1095	Tailblock	$0.1624	$119.80	$160.41	$214.77	$286.47	$279.96	$159.87	$1,221.28								
1096	HB Threshold	1,000															
1097																	
1098	**Summer:**																
1099	Cust. Chg	$172.33								$172.33	$172.33	$172.33	$172.33	$172.33	$172.33	$1,034.00	$2,068.00
1100	Headblock	$0.1766								$176.63	$176.63	$176.63	$176.63	$176.63	$176.63	$1,059.80	$2,522.28
1101	Tailblock	$0.1004								$78.01	$31.92	$19.97	$30.84	$12.72	$44.86	$218.32	$1,439.60
1102	HB Threshold	1,000															
1103																	
1104	Total Base Rate Amount		$535.88	$576.48	$630.85	$702.55	$696.04	$575.95	$3,717.76	$426.98	$380.89	$368.93	$379.81	$361.68	$393.83	$2,312.12	$6,029.87
1105																	
1106	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4346								
1107	COG amount - Winter		$2,177.97	$2,491.37	$3,021.27	$4,330.43	$4,267.64	$3,109.01	$19,397.68								
1108																	
1109	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.7099	$1.1615
1110	COG amount - Summer									$1,116.26	$827.84	$823.20	$1,015.22	$884.56	$1,136.02	$5,803.09	$25,200.77
1111																	
1112	LDAC	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855
1113	LDAC amount		$148.58	$169.96	$198.59	$236.34	$232.92	$169.68	$1,156.07	$151.95	$112.69	$102.51	$111.77	$96.33	$123.72	$698.97	$1,855.04
1114																	
1115	**Total Bill**		**$2,862.43**	**$3,237.81**	**$3,850.70**	**$5,269.32**	**$5,196.60**	**$3,854.64**	**$24,271.50**	**$1,695.18**	**$1,321.42**	**$1,294.64**	**$1,506.79**	**$1,342.57**	**$1,653.57**	**$8,814.18**	**$33,085.69**
1116																	
1117	**Winter Season (Jan. - Apr., Nov. - Dec.)**									**Summer Season (May - Oct.)**							
1118	**Keene Commercial/Industrial to EnergyNorth Commercial/Industrial - Medium Annual Use, Low Winter Use (G-52)**																
1119	**CURRENT**																**Total**
1120			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer**	**2017/18**
1121	**average Usage (Therms)**		1,738	1,988	2,323	2,764	2,724	1,985	13,521	1,777	1,318	1,199	1,307	1,127	1,447	8,175	21,696
1122																	
1123	**Winter:**																
1124	Cust. Chg	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00								
1125	Block 1	$1.1522	$92.18	$92.18	$92.18	$92.18	$92.18	$92.18	$553.06								
1126	Block 2	$0.9442	$113.30	$113.30	$113.30	$113.30	$113.30	$113.30	$679.82								
1127	Block 3	$0.7946	$1,221.92	$1,420.62	$1,686.64	$2,037.53	$2,005.68	$1,418.01	$9,790.41								
1128	BL1 Threshold	80															
1129	BL2 Threshold	120															
1130																	
1131	**Summer:**																
1132	Cust. Chg	$18.00								$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$108.00	$216.00
1133	Block 1	$1.1522								$92.18	$92.18	$92.18	$92.18	$92.18	$92.18	$553.06	$1,106.11
1134	Block 2	$0.9442								$113.30	$113.30	$113.30	$113.30	$113.30	$113.30	$679.82	$1,359.65
1135	Block 3	$0.7946								$1,253.24	$888.37	$793.76	$879.83	$736.34	$990.85	$5,542.39	$15,332.80
1136	BL1 Threshold	80															
1137	BL2 Threshold	120															
1138																	
1139	Total Base Rate Amount		$1,445.40	$1,644.10	$1,910.12	$2,261.01	$2,229.16	$1,641.49	$11,131.29	$1,476.72	$1,111.85	$1,017.24	$1,103.31	$959.82	$1,214.33	$6,883.27	$18,014.56
1140																	
1141	COG Rate - (Winter)		$1.2533	$1.2533	$1.3008	$1.5666	$1.5666	$1.5666	$1.4346								
1142	COG amount - Winter		$2,177.97	$2,491.37	$3,021.27	$4,330.43	$4,267.64	$3,109.01	$19,397.68								
1143																	
1144	COG Rate - (Summer)									$0.6281	$0.6281	$0.6866	$0.7766	$0.7851	$0.7851	$0.7099	$1.1615
1145	COG amount - Summer									$1,116.26	$827.84	$823.20	$1,015.22	$884.56	$1,136.02	$5,803.09	$25,200.77
1146																	
1147	LDAC	$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	$0.0000
1148	LDAC amount		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1149																	
1150	**Total Bill**		**$3,623.37**	**$4,135.47**	**$4,931.39**	**$6,591.44**	**$6,496.80**	**$4,750.49**	**$30,528.97**	**$2,592.98**	**$1,939.69**	**$1,840.44**	**$2,118.52**	**$1,844.38**	**$2,350.35**	**$12,686.37**	**$43,215.33**
1151																	
1152	**DIFFERENCE:**																
1153	**Total Bill**		**($760.94)**	**($897.66)**	**($1,080.69)**	**($1,322.12)**	**($1,300.20)**	**($895.86)**	**($6,257.46)**	**($897.79)**	**($618.27)**	**($545.80)**	**($611.73)**	**($501.81)**	**($696.78)**	**($3,872.19)**	**($10,129.65)**
1154	% Change		**-21.00%**	**-21.71%**	**-21.91%**	**-20.06%**	**-20.01%**	**-18.86%**	**-20.50%**	**-34.62%**	**-31.87%**	**-29.66%**	**-28.88%**	**-27.21%**	**-29.65%**	**-30.52%**	**-23.44%**
1155																	
1156	**Base Rate**		($909.52)	($1,067.62)	($1,279.27)	($1,558.46)	($1,533.12)	($1,065.54)	($7,413.53)	($1,049.74)	($730.96)	($648.31)	($723.50)	($598.14)	($820.50)	($4,571.16)	($11,984.69)
1157	% Change		-62.93%	-64.94%	-66.97%	-68.93%	-68.78%	-64.91%	-66.60%	-71.09%	-65.74%	-63.73%	-65.58%	-62.32%	-67.57%	-66.41%	-66.53%
1158																	
1159	**COG & LDAC**		$148.58	$169.96	$198.59	$236.34	$232.92	$169.68	$1,156.07	$151.95	$112.69	$102.51	$111.77	$96.33	$123.72	$698.97	$1,855.04
1160	% Change		6.82%	6.82%	6.57%	5.46%	5.46%	5.46%	5.96%	13.61%	13.61%	12.45%	11.01%	10.89%	10.89%	12.04%	7.36%

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 17-048

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

Petition for Permanent and Temporary Rates

Order Approving Permanent Rates

ORDER NO. 26,122

April 27, 2018

APPEARANCES: Michael J. Sheehan, Esq., on behalf of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities; the Office of the Consumer Advocate by D. Maurice Kreis, Esq., on behalf of residential ratepayers; and Paul B. Dexter, Esq., and Alexander F. Speidel, Esq., on behalf of Commission Staff.

In this order, the Commission approves, for the first time in New Hampshire, a decoupling mechanism which allows rate adjustments for weather, energy efficiency, economic effects, and other variables and allows Liberty to earn distribution revenues on a per customer basis, thus eliminating substantial revenue risks. Paired with this innovative decoupling mechanism is a modified rate design that lowers fixed customer charges. The reduction in risk leads to a return on equity of 9.3 percent, which represents a 10 basis point reduction in the return on equity agreed to by Liberty, the OCA, and Staff.

With respect to the numerous revenue and expense issues, the Commission grants a permanent rate increase for Liberty Utilities (EnergyNorth Natural Gas) Corp., effective May 1, 2018, of $8,060,117 in distribution rates, with a step increase effective the same date estimated to be $4,729,953, for certain non-revenue-producing investments made during 2017, offset by a $2,394,065 reduction due to tax reform. The Commission also consolidates the Keene Division with Liberty's other operating areas for distribution rate purposes, and all

Liberty customers will pay the same distribution rates. A Liberty residential customer (except those in the company's Keene Division) who uses 760 therms per year, is expected to see a total annual bill increase of approximately $85 (or 7.8 percent) as a result of the rate changes. A Liberty residential customer in Keene who uses 693 therms per year will see a decrease of approximately $73 (or 4.6 percent).

I. PROCEDURAL HISTORY

Liberty Utilities (EnergyNorth Natural Gas) Corp. (Liberty or the Company) currently operates two gas divisions in New Hampshire, its EnergyNorth Division, where it serves over 90,000 customers in southern and central New Hampshire and Berlin, and its Keene Division, where it serves approximately 1,200 propane air customers in the City of Keene. On April 28, 2017, Liberty filed a Petition for Permanent and Temporary Rates. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2017/17-048.html.

Liberty's petition requested that the Commission grant: (1) a permanent increase in Liberty's distribution rates effective with service rendered on or after July 1, 2017, designed to yield an increase of $13,749,361 in annual revenues; (2) temporary rates effective with service rendered on or after July 1, 2017, designed to yield an increase of $7,778,497 in annual revenues for its EnergyNorth Division, pending the Commission's final determination on the Company's request for a permanent rate increase; and (3) a step adjustment in rates designed to yield an increase of $6,071,562 in annual revenues (to recover costs associated with approximately $41 million of capital expenditures projected to be made during 2017) to be effective no earlier than January 1, 2018. Liberty proposed that the new permanent rates apply to customers in both its EnergyNorth Division and its Keene Division; that is, the Company sought to consolidate its two divisions for purposes of distribution rates.

Liberty's filing included direct testimony and exhibits in support of the proposed rates, and related supplemental information, including the proposed tariff, in accordance with N.H. Code Admin. Rules Puc 1600. By letter dated April 3, 2017, the Office of Consumer Advocate (OCA) indicated that it would be participating in the proceeding pursuant to RSA 363:28.

In Order No 26,015, dated May 8, 2017, the Commission suspended the effectiveness of the permanent rate pending investigation. In Order No. 26,035, dated June 30, 2017, the Commission authorized a temporary rate increase for customers in the EnergyNorth Division designed to collect $6,750,000 on an annual basis. No temporary rates were requested for the Keene Division. Pursuant to RSA 378:29, the permanent rates authorized in this case will be reconciled back to the effective date of the temporary rates, July 1, 2017.

The Commission held a pre-hearing conference in this matter on May 26, 2017, followed by a technical session. Subsequently, the Staff of the Commission (Staff) and the OCA issued several sets of data requests, which Liberty answered. Liberty, Staff, and the OCA met in technical sessions on August 23, August 24, November 1, and November 2, 2017. On November 30, Staff submitted testimony recommending a rate increase for the EnergyNorth Division of $4.0 million annually, effective May 1, 2018, and a step increase effective that same day of $4.3 million. Staff proposed that no change be made to Keene Division rates at this time. The OCA recommended a rate increase of $9.2 million annually for the EnergyNorth Division. Like Staff, the OCA recommended no change to Keene Division rates at this time. Both Staff and the OCA recommended against the proposed consolidation of Keene into EnergyNorth for purposes of distribution rates, because the consolidation would create a subsidy of the Keene customers by the EnergyNorth customers.

On January 25, 2018, Liberty filed rebuttal testimony wherein it revised its requested revenue deficiency to $14.5 million. On February 27, 2018, Liberty filed a settlement signed by Liberty and the OCA, which if adopted would resolve all issues in this proceeding. The settlement called for a rate increase of $10.3 million effective May 1, 2018, with a step adjustment of $5.0 million effective the same day. The settlement would establish a return on equity of 9.4 percent. It would also consolidate the rates for the EnergyNorth and Keene Divisions and adopt a decoupling mechanism. Staff opposed adoption of the settlement stating that, in its view, the settlement would not result in just and reasonable rates, although Staff supported the settlement return on equity of 9.4 percent and certain other terms as reasonable.

Below, we review the record, including the settlement agreement signed by Liberty and the OCA, and make the findings required to support the rate increases and changes approved in this order. Before doing that, however, we address a request for confidentiality of certain records.

II. STAFF'S MOTION FOR CONFIDENTIAL TREATMENT

Staff filed a motion for confidential treatment of certain information contained in a report from The Liberty Consulting Group (LCG) entitled "Recommendations Verifications of Liberty Utilities." On November 30, 2017, Staff filed the LCG report with two redacted data points, as requested by Liberty, concerning Customer Care Department employee engagement scores. Subsequent to filing the report, Staff noted two additional unredacted scores. Consistent with Liberty's initial position (Data Response Staff 6-38), Staff argued that confidential treatment is required because the data points pertain to "internal personnel practices and otherwise confidential information." RSA 91-A:5, IV. Neither Liberty nor the OCA objected to the motion. At a hearing held on March 6, 2018, the Commission stated that it would treat the information as confidential but, would review the motion in more detail and rule after the hearing.

We first address whether the employee engagement scores should be exempt from public disclosure because such information constitutes confidential personnel data. The New Hampshire Right-to-Know Law provides each citizen with the right to inspect all public records in the Commission's possession. RSA 91-A:4, I. Exceptions include "records pertaining to internal personnel practices." RSA 91-A:5, IV. Both Staff and Liberty stated that the employee engagement scores are a record of internal personnel practices, thus requiring confidential treatment.

The New Hampshire Supreme Court, agreeing with the United States Supreme Court, interpreted "personnel ... when used as an adjective, refers to human resources matters." *Clay v. City of Dover*, 169 N.H. 681, 686 (2017) (citations omitted). The data points at issue in this case relate to an employee engagement survey, which gauges Liberty's efforts to bolster employee retention. The Commission finds that these data points pertain to overall employee satisfaction and this falls under the category of human resource matters. Thus, these data points relate to internal personnel practices, and are exempt from the New Hampshire Right-to-Know Law. Accordingly, we hereby grant Staff's Motion. *See Hounsell v. North Conway Water Precinct,* 154 N.H. 1, 3 (2006); *Union Leader v. Fenniman,* 136 N.H. 624, 627 (1993) (customary balancing of interests not required with regard to personnel practices exemption).

III. LIBERTY/OCA SETTLEMENT

The settlement filed by Liberty and the OCA calls for rates (which would be paid by both the EnergyNorth and Keene Division customers) that would increase revenues by $10.3 million annually, with a step adjustment effective May 1, 2018, of $5.0 million. The settlement contains a 9.4 percent return on equity.

The settlement increase of $10.3 million, while not itemized, was intended to resolve all revenue requirement issues raised in the case. By its own terms, the settlement states that it reflects resolution of many such issues, including weighted average cost of capital, capital structure, return on equity, prepayments, materials and supplies, the Concord training center, depreciation and amortization, investments to serve iNATGAS, Keene production costs, and Keene emergency response costs. Other revenue requirement issues that were raised by Staff in this case and that would be resolved by the settlement (although not specifically identified in the settlement) include customer count for purposes of calculating revenues, payroll expense related to vacancies, incentive-based pay and severance pay, and test year consulting services.

The settlement also includes important non-revenue provisions, including consolidation of the rates charged by the Keene Division and the EnergyNorth Division, as well as a decoupling plan under which revenue per customer targets would be established for each rate class. Each month, and again at the end of each year, rates would be adjusted up or down to allow the Company to collect the established revenue per customer targets. The monthly adjustments would account for changes in weather. In months when temperatures were colder than normal, customers would receive a credit on their bill to return the increased revenues that Liberty would have collected due to higher usage during the colder than normal temperatures. During warmer months, customers would pay a charge to make up for the reduced revenues attributable to the warmer temperatures. The annual adjustments would account for changes other than weather, such as decreased revenues due to energy efficiency, increased revenues due to favorable economic conditions, and other changes in revenues. Under the settlement, customer charges for residential customers would be reduced and existing declining rate blocks would be flattened.

IV. COMMISSION ANALYSIS

In this case, the Commission is presented with an unusual situation where it is asked to approve a settlement that is supported by the applicant (Liberty) and the OCA, but not by Staff. Staff's position is that the Commission should reject the settlement because it will not produce just and reasonable rates.

The Commission's process for reviewing a settlement is well established. Under RSA 541-A:31, V(a), informal disposition may be made of any contested case at any time prior to the entry of a final decision or order, by stipulation, agreed settlement, consent order, or default. N.H. Code Admin. Rules Puc 203.20(b) requires the Commission to approve the disposition of a contested case by settlement if it determines that the settlement results are just and reasonable and serve the public interest. In general, the Commission encourages parties to attempt to reach a settlement of issues through negotiation and compromise, as it is an opportunity for creative problem solving, allows the parties to reach a result more in line with their expectations, and is often a more expedient alternative to litigation. *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,* Order No. 25,202 at 17 (March 10, 2011). Even where all parties join a settlement agreement, however, the Commission cannot approve it without independently determining that the result comports with applicable standards. *Id.* at 18. In this case, where Staff has testified that the settlement will not produce just and reasonable rates, our independent review of the settlement terms is of even greater importance than usual.

We are mindful of Section III of the settlement, which contains typical settlement language that the settlement is expressly conditioned on the Commission's acceptance of all of its terms, without change or condition. The central issue of this case is the rate increase request. As indicated, the latest request, as set out in Liberty's rebuttal testimony, is for a rate increase of $14.5 million (and a request for approval to consolidate EnergyNorth and Keene Division rates). Staff's updated recommended revenue increase (applicable only to the EnergyNorth Division) was $5.7 million. Exh. 53 at 6. The settlement revenue requirement increase is $10.3 million. Exh. 29 at 3.

Given the wide divergence of these amounts, the Commission undertook a review of the various issues raised in the case concerning the appropriate revenue requirement in order to test the just and reasonableness of the settlement rate increase of $10.3 million. That review is detailed in the pages that follow. It concludes that a reasonable revenue requirement deficiency for Liberty in this case is $8,060,117 on a consolidated basis (*i.e.*, applicable to EnergyNorth and Keene customers under consolidated rates). Because that amount is significantly different from the settlement revenue deficiency, we conclude the best course of action is to reject the settlement in its entirety and instead order a rate increase of $8,060,117 based on our resolution of the underlying issues. In addition, we address the various other issues raised in this case that do not directly affect revenue deficiency, such as rate design and decoupling.

In the following sections, unless otherwise noted, Liberty's positions are taken from a combination of its original filing, and when appropriate, its rebuttal testimony and exhibits. The OCA's positions are taken from its original filing. For many of the issues discussed below, the settlement did not specifically address the issue. Instead, the settlement purported to resolve all issues raised by Staff and the OCA. To the extent the settlement discussed an issue, we describe the settlement position separately.

A. Revenues – Year-End Customer Count vs. Average Customer Count

Liberty. Liberty based its revenue deficiency calculation on test year (2016) revenues with certain adjustments to, among other things, reflect normal weather, annualize for special contract revenues that were not fully reflected in the test year revenues, and reflect a mid-year increase in cast iron and bare steel replacement revenue. Exh. 3 at 47. Liberty did not adjust test year revenues to reflect revenues from customers that were added during the test year.

OCA. The OCA took no position on the revenue adjustments proposed by Liberty.

Staff. Staff accepted the revenue adjustments proposed by Liberty and proposed an additional adjustment designed to reflect increased revenue from customers added during the test year. Staff's adjustment takes year-end customer counts and calculates a revenue adjustment by multiplying the difference in customer bills at year end by average customer usage, by rate class. The adjustment adds $929,551 to test year revenues, and thus reduces Liberty's requested revenue increase by the same amount. Exh. 40. In support of this adjustment, Staff stated that many inputs to a utility's revenue requirement calculation are adjusted for known and measurable changes during and beyond the test year. Rate base is calculated using year-end, plant balances. Many operation and maintenance (O&M) expenses, including payroll, pensions, property taxes, and the PUC assessment are adjusted for post-test year amounts. 3/14/18 AM, Tr. at 34-36. Further, Staff argued, absent this adjustment, the plant used to serve a customer added during the test year would be in rate base at full value, while only a portion of that customer's revenues would be reflected in the revenue deficiency. 3/14/18 AM, Tr. at 31-34.

Ruling. The Commission finds that Staff's revenue adjustment is reasonable. As Staff noted, many aspects of the revenue deficiency calculation in this case have been updated to reflect known and measurable changes during and beyond the test year. Staff's adjustment better matches plant investments with the revenues realized from those investments and therefore produces a more accurate picture of Liberty's revenues in the period when rates will be in effect.

B. O&M Expenses, Payroll – Vacancies

Liberty. Liberty's revenue requirement calculation included payroll costs for a full complement of employees as of December 31, 2017, one full year after the test year. Exh. 3 at 14-15 and 48. The payroll amount was estimated when Liberty filed its case in May 2017, and the amount was updated in Staff Tech 1-1, filed November 21, 2017. Exh. 17 at 83. Liberty stated that it needs a full complement of employees to perform its necessary tasks. To the extent that a position was vacant during the test year, the tasks of that position were done by temporary employees and/or permanent employees working overtime.

OCA. The OCA took no position on the revenue adjustments related to vacancies proposed by Liberty.

Staff. Staff proposed a reduction in payroll expenses to reflect the equivalent of 3.5 vacancies of a workforce of over 300, which is the average of two historical data points for vacancies: three at January 1, 2016 (the start of the test year), and four as of November 1, 2017, just before Staff's testimony was filed. *Id.* at 21. Staff's position is that vacancies recur and should be reflected in a ratemaking payroll amount that is based on budgeted figures. Further, Staff notes that to the extent the duties of vacated positions were performed by temporary workers, the costs associated with those workers would have been reflected in test year O&M expenses, as outside services. Finally, according to Staff, absent the adjustment, Liberty's proposed payroll expense would be 5.3 percent above test year levels, which is almost twice the average of actual annual payroll increases of 2.7 percent over the past three years. *Id.* at 21-22.

Ruling. Liberty's presentation of rate case payroll is difficult to assess. The Commission prefers a more traditional approach where a utility develops a reasonable test year payroll amount and then applies known and measurable percentage payroll increases to that normalized test year amount. We find Staff's proposed adjustment reasonable. Vacancies are a fact of doing business and should be accounted for when calculating a payroll figure for ratemaking purposes that includes a level of employees that is adjusted beyond the test year, as is the case here. A vacancy level of 3.5 out of a total of over 300 positons is about a 1 percent vacancy rate, which we find reasonable, if not unrealistically low. Furthermore, Staff's adjustment is a smaller reduction than would have been warranted under a more traditional approach to calculating a ratemaking payroll amount, and therefore is reasonable for purposes of this case. Exh. 17 at 21-22.

C. <u>O&M Expenses, Payroll - Incentive Based Pay</u>

Liberty. Liberty's rate request included payroll costs associated with its long-term incentive plan. According to Liberty, incentive compensation pay is a common method of compensating employees and is necessary to attract and retain employees. Exh. 23 at 16.

OCA. The OCA took no position on the questions of incentive based compensation.

Staff. Staff recommended that the Commission deny recovery of $52,000 of Liberty's compensation amount because it was tied to incentives designed to benefit shareholders, but not necessarily customers. Exh. 17 at 60. Staff's adjustment represented approximately five percent of Liberty's requested incentive-based compensation. Exh. 3 at 48. In Staff's view, incentives that reward net income or return on investments are focused on benefits to shareholders. *Id.* at

27. Employees seeking to achieve those targets could do so at the expense of customer service; for example, a reduction in vegetation management (for an electric company) would increase earnings, but could result in a degradation of customer service. 3/21/18, Tr. at 120-121. To remove that possible incentive, Staff recommended that compensation resulting from such incentive targets be excluded from the Company's revenue requirement.

Ruling. The Commission appreciates both the Company's position that incentive-based payroll is standard in today's utility industry and may be required to attract and retain quality employees, and Staff's position that payroll tied to earnings could provide incentives that might result in degradation of customer service. There is no solid evidence, however, that either of those hypotheses is actually valid in the case of EnergyNorth. Because the amount of compensation tied to earnings-based incentives is quite small ($52,000 out of a total company payroll expense of $14,518,000 (Exh. 17 at 83)), the Commission finds Staff's adjustment unnecessary. If the percentage of compensation based on net earnings or stock price were higher, we would take a harder look at the amounts to be included.

D. <u>O&M Expenses, Payroll - Severance Pay</u>

Liberty. Liberty's requested revenue requirement in this case included $144,130 of severance pay, of which $78,000 was related to employees who resigned. Exh. 42; Exh. 17 at 65. Liberty stated that all of the resignations were involuntary and may have involved situations in which the employees granted a release from liability. 3/14/18 AM, Tr. at 46-47,67. Liberty argued that such costs should be included in rates for a number of reasons: (a) severance pay is a normal cost of doing business, (b) not allowing recovery of severance pay could result in higher costs because severance pay can be the least expensive means to resolve an employee dispute, and (c) disallowing severance pay would be substituting the Commission's judgment for the

Company's, which would be particularly inappropriate in this instance where the Commission does not know the specific circumstances under which the severance payments were made. Exh. 23 at 20.

OCA. The OCA took no position on the issue of severance pay.

Staff. Staff believes ratepayers should not pay for costs of removing employees. Ratepayers will have already borne the cost of paying all of the Company's employees to perform. If circumstances are such that employees are being "asked" to resign, ratepayers should not bear the costs. Shareholders should carry the costs of bad hiring decisions, and if the least cost means of removing employees is severance pay, then Liberty should take that course to reduce its costs to shareholders. 3/21/18, Tr. at 129-130.

Ruling. The Commission is persuaded by Staff's position that ratepayers should bear the expense of payroll for services provided, but should not bear severance costs related to employees who resign to avoid being fired. Layoffs (where Staff did not recommend disallowance of related severance pay) could involve reductions in work force where the saved payroll expense would find its way into lower rates. Involuntary resignations, on the other hand, may involve subpar performance, and customers should not be required to bear an underperforming employee's payroll and the severance cost incurred to remove that same employee.

E. <u>Expenses - Consulting Services</u>

Liberty. During the test year, Liberty incurred $43,000 in consulting fees to analyze the proposed Northeast Direct Pipeline (NED) project, which was to bring additional gas supplies to Liberty's service area. The NED project was ultimately abandoned by its developer. Liberty's revenue requirement included full recovery of the $43,000 in rates. Liberty opposed any reduction in this amount because, in the Company's view, consulting fees are an ongoing cost of doing business. While this particular project may have been cancelled, other similar consulting arrangements are likely to be needed every year and thus should be reflected in rates. Exh. 23 at 14-15.

OCA. The OCA took no position on Liberty's consultant expenses.

Staff. Staff recommended that the NED consulting costs be amortized over a three-year period, the effect of which would be that only one third of the expense ($14,000) would be reflected in the rates established in this case. Staff's opinion is that consulting expenses are non-recurring and thus amortization of the NED expense is appropriate so that ratepayers do not pay for the full amount each year. Exh. 17 at 20.

Ruling. The Commission finds that modest consulting costs, like those at issue here, are an ongoing part of a regulated utility's business and should not be amortized. Therefore, the full $43,000 may be included in Liberty's revenue requirement. If the consulting costs were much more significant, amortization might be appropriate.

F. <u>Expenses, Depreciation – Average Service Lives</u>

Liberty. Liberty presented a full depreciation study that was prepared and presented by Paul Normand, who performed EnergyNorth's last depreciation study. Mr. Normand recommended that the average service lives (ASL) of many asset groups be changed from the last study. For example, for account 380.00 – Services, which makes up over 30 percent of the Company's total plant, Mr. Normand recommended that the ASL be increased from 40 years to 45 years. Exh. 10 at 447. For Account 367 – Mains (which makes up almost 50 percent of total company plant), Mr. Normand recommended that the ASL remain at 60 years. *Id.* at 445. Mr. Normand based his recommendations on the results of a recognized and commonly used depreciation model when he considered the model results reasonable. When the model results did not produce results that in his opinion were reasonable, he looked for other information on which to base his conclusions. For example, in the case of account 303.03 – Capitalized Software, Mr. Normand stated that the model results were not reasonable. Exh. 69 at 2-4 (labeled p. 25-27 of 36); Tr. 3/26/18 at 149-152. In that instance, Mr. Normand requested specific information from Liberty regarding the ASLs of the Company's various software packages and used those ASLs in his study results. Exh. 10 at 436; 3/26/18, Tr. At 151-155. In general, in situations where the plant had a communication function, such as automated meters, Mr. Normand relied on his professional judgment in arriving at a shorter ASL due to shortened lives of technology. 3/26/18, Tr. at 156-157.

OCA. The OCA took no position on ASLs.

Staff. Staff agreed with many of the changes to ASLs based on the model results. *See*, *e.g.*, Exh. 18 at 31, Account 320.10 – Other Equipment – Production; Exh. 10 at 440 where Liberty proposed to lengthen the existing ASL from 30 years to 35 years and Staff agreed. When Staff deemed Mr. Normand's study results unreliable, Staff recommended that the last authorized ASLs be used. 3/26/18, Tr. at 198-202. *See, e.g.,* Exh. 18 at 31, Account 303.00 – Capitalized Software. In addition, in the case of meters, where the study analyzed this plant category at the sub-account level for the first time, Staff recommended a more gradual approach. Exh. 18 at 5-6. For example, concerning sub-account 381.20 – Meters – ERTS, Liberty recommended changing the existing life from 35 years to 15 years, while Staff proposed 25 years. Exh. 18 at 5-6 and 32; 3/26/18, Tr. at 203.

Ruling. The Commission is persuaded that Mr. Normand has developed appropriate ASLs for Liberty in this matter. We find his use of extra-study data appropriate in the case of capitalized software and preferable to Staff's reliance on Liberty's prior study. Similarly, we agree with Mr. Normand's judgment that a shorter ASL is appropriate for plant items with significant electronic components such as Meters – ERTS. The approved ASLs are set forth on Appendix 6 attached to this order.

G. Expenses, Depreciation - Amortization of Reserve Deficiency

Liberty. Liberty's depreciation study shows a per books reserve for depreciation as of December 31, 2016, equal to $155,247,000. Mr. Normand calculated a theoretical reserve as of that same date of $165,194,000, leaving a variance of $9,947,000. Exh. 10 at 464. Liberty proposed to amortize this variance over three years. Because the per books reserve is lower than the theoretical reserve, the amortization would result in an increase to rates of $3,316,000 per year. Exh. 3 at 52. Mr. Normand initially recommended that the variance be amortized over two depreciation cycles, or 12 years. Exh. 10 at 405. Mr. Mullen testified that Mr. Normand's 12-year recommendation was based on the depreciation study in isolation and that a broader view would point to a shorter amortization period. Specifically, Mr. Mullen stated that the deficiency itself had accumulated in part due to a 13-year amortization period for a reserve excess from a prior rate case. According to Mr. Mullen, extending the amortization another 12 years would cause inter-generation equity issues. Exh. 72. At the hearing, Mr. Normand testified that while the typical approach would be to amortize a reserve variance over two depreciation cycles, this did not account for Liberty's unusually high investments in mains. 3/26/18, Tr. At 183-184. Mr. Mullen and Mr. Normand agreed that if a shorter amortization period were used, the variance should be looked at in the next rate case (in advance of the next full depreciation study). Exh. 72; 3/26/18, Tr. At 184.

OCA. The OCA took no position on the amortization of the reserve balance.

Settlement. The settlement calls for amortization of the reserve deficiency over five years and a re-examination of the reserve imbalance in Liberty's next rate case.

Staff. Staff recommended a 12-year amortization, consistent with the current amortization, which is passing funds back to customers. Staff noted that depreciation deals with long-lived assets (up to 60 years for mains, which is the largest portion of EnergyNorth's plant) and thus reserve imbalances should be amortized over relatively long periods of time. Exh. 18 at 6-7. Staff sees no reason why reserve shortfalls should be recovered from customers four times quicker than excesses are returned to customers (three years versus twelve years). 3/26/18, Tr. At 208-210. Further, the reserve deficiency at hand is about 6 percent of the total theoretical reserve and Mr. Normand stated that it would be reasonable to amortize reserve variances only when they exceed a 5-10 percent range. *Id.* at 207; Exh. 71. Based on that opinion, Staff asserted that if no amortization is one option, then certainly an accelerated amortization (three years) is not warranted.

Ruling. The Commission's primary goal in addressing this issue is to achieve a result whereby the utility customers pay through rates a level of depreciation that fairly reflects the assets on Liberty's books, and that will result in as minimal a reserve variance as possible at the time of the next rate case. While the Commission approved a 12-year amortization period in the settlement in DG 08-009 (EnergyNorth's last rate case in which a depreciation study was done), that amortization appears to have gone on too long. The Company has gone from a significant reserve excess ($12.4 million) to a reserve shortfall almost as large ($9.9 million). Exh.72; Exh.10 at 464. A three-year amortization period and, to a lesser extent, the five-year period provided in the settlement, may be an over-reaction to the long amortization period from

DG 08-009. The Commission supports the idea of re-examining this reserve variance in EnergyNorth's next rate case (and this is based in large part on Mr. Normand's testimony that a reserve variance review would be a significantly less complicated and less costly task than a full depreciation study – 3/26/18, Tr. at 196). Thus, we approve a six-year amortization period of the existing test year-end balance and direct the Company to prepare and present in its next rate case, a review of the reserve imbalance, a thorough explanation of the cause of any imbalance, and a proposal for amortizing that reserve imbalance.

H. Rate Base - Prepayments

Liberty. Liberty's rate case presentation included $2,705,000 of prepayments in rate base. That figure represented an average test year amount of which $2,431,000 was for property taxes and $274,000 was for other prepayments. Exh. 3 at 71. Liberty also included a $2,636,000 working capital component added to rate base. In response to Staff's assertion that the two rate base components (prepayments and working capital) overlap, Liberty maintained that any overlap is not dollar for dollar and that prepayments should be left in rate base while working capital could be reduced to remove the expenses related to prepayments. No specific adjustment was proposed by Liberty, but Mr. Mullen testified that an adjustment or allowance of some sort was reflected in the settlement. 3/6/18 AM, Tr. at 24-27.

OCA. The OCA took no position on the issue of including prepayments in rate base.

Staff. Staff examined Liberty's lead/lag study and found that every property tax invoice Liberty paid was included. As part of that study, the tax period covered by each invoice, and the number of days from that tax period until each invoice was paid, was quantified and reflected. Exh. 9 at 389-390. Staff thus concluded that there was no need to also include prepaid property taxes in rate base because all cost of money or working capital required for property taxes is precisely reflected in Liberty's lead/lag study. Exh. 17 at 13-15. Staff's adjustment removes prepayments from rate base to eliminate a double count of the working capital associated with prepaid property taxes. *Id.* Staff also removed other, non-property tax prepayments from rate base on the same theory; i.e., that those items were covered in the lead/lag study as O&M expense – Non-Labor. Exh. 9 at 378-381; Exh.17 at 13-15.

Ruling. The Commission finds that the detailed lead/lag study captures all the working capital requirements related to property taxes and other prepaid expenses. To also include prepayments in rate base would be allowing for a double recovery of the working capital related to those items. Consequently, prepayments may not be included in rate base.

Rate Base - Training Center

Liberty. Liberty included in rate base a net plant value of $3,456,000 for its training center at 10 Broken Bridge Road in Concord. Exh. 17 at 55. The facility was placed in service and booked to plant in 2015, one year prior to the test year at a full cost of approximately $3.8 million. 3/6/18 AM, Tr. at 79. Liberty's proposed rate base cost of service also reflected the test year level of operation and maintenance associated with the training center, as well as rent received from Liberty's New Hampshire electric utility, Granite State Electric Company, pursuant to a lease agreement. Exh. 3 at 57. The training center is approximately 6,000 square feet in size and includes 3,000 square feet of indoor lab space. It includes two classrooms, an outdoor gas leak field, an outdoor pole line, an indoor manhole, live gas appliances, and live electric transformers, switch gear, and meters. Exh. 13 at 23.

According to Liberty, the facility is used and useful. Liberty's view is that the training center represents the most efficient means for it to perform various training exercises, because the environment is controlled and safe, and Liberty owns the facility so it can schedule the facility's use. Exh. 13 at 24. Liberty stated that it explored the possibility of training at other utilities' facilities, but found that was not an available option. *Id.* at 20-21. Similarly, Liberty considered on-the-job-training but determined it would not provide adequate training. *Id.* In addition to using the facility for training, Liberty has located a backup call center in the building. Exh. 18 at 73.

Concerning the cost of the training center, Liberty relied on an audit performed by the Commission's Audit Division, which reviewed all the training center costs and recommended only minor exclusions of costs (approximately $300,000-$400,000). Liberty agreed to exclude approximately $167,000. 3/6/18 PM, Tr. at 91; Exh. 26A at 137. Liberty also noted that LCG reviewed all the training cost expenditures and did not recommend any rate base exclusions. 3/6/18 PM, Tr. at 91. Concerning increases from the original cost estimates, Liberty conceded that its initial cost estimates were "outdated and lacking in several ways." Exh. 13 at 18. Liberty maintained that training center costs were controlled and its investment was cost-effective. *Id.* at 16; Exh. 26A at 136. Liberty disputed Staff's position that the Company's training costs have increased significantly since the training center was built. 3/6/18 PM, Tr. at 27-30.

OCA. The OCA's original position was that all costs associated with the training center be removed from rates based on imprudent planning and mismanagement of the project. *See* Exh. 16 at 228-237.

Settlement. The settlement agreement included the costs of the training center in Liberty's rate base and, according to its terms, reflected in the revenue requirement consideration and compromise of the issues raised by Staff and the OCA. Exh. 29 at 6.

Staff. Staff recommended full exclusion of the training center from rate base and exclusion of the revenues and O&M expenses from Liberty's cost of service on the grounds that

Liberty did not perform adequate analysis of the costs and benefits of building the training center. Staff noted that Liberty's decision to build the training center was based on a business case dated January 24, 2014, in which Liberty stated that its cost would be $1,028,100, and the payback would be less than three years due in large part to $400,000 per year in avoided outside training costs. Exh. 18 at 50. Liberty's senior management approved that business case. 3/6/18 AM, Tr. at 81-82. Staff observed that over half of the $400,000 savings were related to trainer costs, which would not be saved if the training center were built, because Liberty would need to hire two full-time trainers. 3/6/18 AM, Tr. at 89-91; Exh.18 at 58.

According to Staff, Liberty did not perform a quantitative assessment of the efficiencies it expected to achieve by building the training center versus performing on-the-job training. Staff also criticized Liberty for never issuing a Request For Proposals for training services. Exh.18 at 21-22. Staff observed that, even when the projected cost of the facility had doubled (to $2.3 million) and that cost increase was brought to senior management for review in an Over Expenditure Spending Request Form, no quantitative assessment of alternatives to completing the training center was performed. Exh. 31 at 5; 3/6/18 PM, Tr. at 14-15.

Staff asserted that the initial estimate of $1,028,100 did not include site work and was prepared without the benefit of a contractor. Exh. 30. Staff also noted that even after a construction contract was later signed with North Branch Construction, there were many additional items that were not included in the estimate, including costs associated with environmental consulting, overheads/burdens, and Allowance For Funds Used During Construction (AFUDC). 3/6/18 AM, Tr. at 112; Exh. 31 at 3.

Staff suggested that a reasonable utility executive should have known about the various construction and training costs that were either not estimated or were underestimated when the project was first reviewed and approved by Liberty's senior management. Staff maintains that, when the significant cost increases were presented to senior management in the Over Expenditure Spending Request Form, Liberty should have re-examined its options for training instead of making unsupported claims that alternatives were "expensive" and "not feasible." Exh. 31 at 4-5; 3/6/18 PM, Tr. at 14-15. Staff believes that if proper analyses were performed then Liberty would have decided against building the training center. Exh. 18 at 19-25. Because such analyses were not performed, Staff maintains that no training center related costs should be charged to customers. Staff also noted that the costs of training have increased significantly since the training center was built. *Id.*

Ruling. Many prior Commission decisions give guidance as to the appropriate standard to apply when evaluating the prudence of a utility's investment. Pursuant to RSA 378:28, the Commission shall not include in permanent rates any return on any plant, equipment, or capital improvement which has not first been found by the Commission to be prudent, used, and useful. *Pittsfield Aqueduct Company, Inc.,* Order No. 25,051 at 13 (December 11, 2009). When reviewing whether a utility has been prudent in its decision making, we "may reject management decisions when inefficiency, improvidence, economic waste, abuse of discretion or action inimical to the public interest are shown." *Public Service Company of New Hampshire,* Order 25,565 at 20 (August 27, 2013) (citing *Appeal of Easton*, 125 N.H. 205, 215 (1984)). "One of the critical prudence considerations when evaluating actions and decisions, is not to apply the perspective of hindsight, but rather to consider the actions in light of the conditions and circumstances as they existed at the time they were taken." *Public Service Company of New Hampshire,* Order No. 24,108 at 26 (December 31, 2002).

The record in this case indicates that Liberty's senior management decided to construct the training center based on the business case dated January 24, 2014, (Exh. 18 at 48-51), which showed its projected cost as $1,028,100 and its projected savings as $400,000, resulting in a three-year payback. Based on those parameters, as Staff noted, the decision to proceed with the project could be found to be prudent. Prior to commencing construction, however, the Commission expects a reasonable utility executive to make certain that projected costs are accurate and reasonable and have been appropriately evaluated.

Concerning projected costs, the record demonstrates that the $1,028,100 was not a reasonable estimate. First, it did not include site work (defined by Liberty as excavation, surveying, and related work – 3/6/18 AM, Tr. at 100), which is essential to any project being built from the ground up, as this project was. Site work proved to be significant in this case, (estimated at $328,000 by North Branch consulting) and there is no explanation as to why this item should have been excluded from the business case analysis. In addition, the business case was prepared without the benefit of a contractor bid, despite the fact that the estimated contractor costs of $439,000 made up over 40 percent of the total projected costs of $1,028,100. A reasonable decision maker would have sought bids for this significant cost element before proceeding. Again, contractor costs proved very significant. A September 2014 contract with North Branch called for over $2 million in costs - nearly five times the amount built into the original estimate. Further, when the contract with North Branch was signed, all parties involved knew that additional costs would be involved. 3/6/18 AM, Tr. at 112. Such costs included basic building components like architectural fees, civil engineering fees, security costs, burdens (overhead), other contractor costs, environmental consulting costs, AFUDC, and others which ultimately totaled over $1.2 million. Exh. 56 at 95-96. A reasonable decision maker, knowing that additional costs were not covered in the contractor bid, would have sought to have those costs estimated and included in the evaluation process.

In August 2014, after construction had begun on the training center, Liberty's senior management was presented with an Over Expenditure Spending Request Form seeking approval of an additional $1.2 million, bringing the projected cost of the center to $2,347,000. Exh. 31 at 4. That Form identified wetlands, soil conditions, and drainage issues as the primary reasons for the additional costs. *Id.* At that time, Liberty was aware of its obligation to rebuild Broken Bridge Road, and to extend the municipal water system to the facility, yet those costs were not mentioned or reflected in the Over Expenditure Spending Request Form. Exh. 33 at 5; 3/14/18 PM, Tr. at 40-41. In fact the municipally-imposed costs were not reflected until June 2015, one year after Liberty knew of those obligations. Exh. 56 at 95. Given this increase in the estimated costs – more than double – a reasonable executive would have performed an extensive, detailed analysis of the costs to complete the project and the cost of any alternatives to completion.

Concerning the projected savings contained in the January 24, 2014, business case, Staff correctly noted that over half of the projected savings were for trainer costs that would not be avoided if training were brought in house because trainers would need to be hired.

While Liberty discussed economic and non-economic reasons for pursuing the training center, and resulting efficiencies, the Company made no attempt to evaluate those factors in a systematic, complete format. Exh. 18 at 56-57, 62, 68 and 72. Such an analysis is fundamental to ensure that a significant investment is prudent. Other than the flawed three-year payback analysis presented with the January 24, 2014, business case, Liberty performed no financial analysis of this project. We believe that Liberty should have performed a robust financial analysis of this project at its outset, and should have examined the project when costs began to increase significantly shortly after its initial estimate.

Liberty appears to rely on the used and useful portion of the prudence standard to support its request for full recovery of the training center investment. Staff advocates for full exclusion of the training center costs from rates, on the basis of imprudence. We reject both Liberty's and Staff's positions because, although arguably imprudent, the center, now constructed and in use, provides value to Liberty and its ratepayers for training and for its use as a back-up call center. These functions support the Company's delivery of safe and adequate service. Therefore, we will allow the inclusion of some of the Company's investment in the training center in its rate base.

We find that Liberty can place in rate base and recover the cost of the training center as presented in the August 2014 Over Expenditure Spending Request Form, or $2,347,000. This figure is close to the North Branch contractor estimate of $2,042,000 which included many essential elements that were overlooked in the original business case estimate of $1,028,100. The amount in the August 2014 Form bears some reasonable relation to what an independent contractor thought the building could be built for, and allows additional funds for contingencies and items that were not covered by the contract. Liberty failed to demonstrate that costs beyond the $2,347,000 were prudently incurred, and we will not permit those costs to be included in rates. We will allow all test year operation and maintenance expenses related to the center, because we recognize that those costs will not diminish based on our rate base exclusion and are needed for successful operation of the facility. We find this result appropriately balances the various aspects of our prudent, used and useful standard. *See Boston Gas Co.*, Mass. Dep't of Telecommunications and Energy, DTE 03-40 (2003) wherein the Department made several rate base exclusions of capital project cost overruns because the decisions to incur the over-expenditures were not supported by record evidence.

I. Rate Base - iNATGAS

Liberty. Liberty's proposed rates reflected full inclusion of the $4,816,000 investment Liberty made to provide service pursuant to a special contract with Innovative Natural Gas (iNATGAS), a seller of bulk compressed natural gas (CNG) for transport and for vehicle refueling located on Broken Bridge Road in Concord. The special contract included lease payments to Liberty for land, minimum (take-or-pay) payments for CNG, and volumetric payments to Liberty for CNG. This special contract was reviewed and approved by the Commission in *Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities,* Order No. 25,694 (July 15, 2014), issued in Docket No. DG 14-091. At that time, Liberty's level of investment in the facility was projected to be $2,245,000. The lease was projected to produce different revenue streams under various possible scenarios. The net present values (NPV) of the revenue streams, analyzed over 15 years, were: $1,767,000 under a minimum take-or-pay revenue scenario; $4,732,000 under a baseline scenario of revenues; and $5,541,000 under an accelerated sales assumption level. Exh. 38 at 2.

The final installed cost of Liberty's investment was $4,816,000. 3/6/18 PM, Tr. at 101. The first vehicle fuel sales were made in early 2017 and the first bulk sale to a tractor-trailer customer took place in December 2017. *Id.* Liberty maintains that this arrangement provides benefits to customers, when analyzed over a 15-year period using current costs, excluding an allowance for funds used during construction (AFUDC), at all three revenue scenarios. Liberty forecasts that the facility has the potential to provide significant additional benefits to customers in the future. Liberty claims that its decision to enter into the project was prudent, the plant is used and useful, and thus the cost of the plant and the resulting revenues should be reflected fully in rates. Exh. 24 at 72. In addition, Liberty states that the arrangement provides benefits to existing firm customers in the form of interstate pipeline capacity credits, based on iNATGAS's peak day load. *Id.* at 71-72. According to Liberty, the costs of the facility were reviewed by the Commission's Audit Division and LCG and neither recommended excluding any portion of the facility from rate base. 3/14/18 PM, Tr. at 86.

OCA. The OCA took no position on the iNATGAS investment.

Settlement. The settlement agreement states that the revenue requirement reflects a compromise of the issues raised by Staff related to iNATGAS.

Staff. Staff recommended that Liberty be allowed to recover the revenue requirement associated with the cost of the facility as presented in DG 14-091 ($2,245,000), and that Liberty be required to bear all costs beyond that level, at least until Liberty's next rate case, at which time the project could be re-evaluated using actual sales numbers and costs. Staff did not request a full denial of cost recovery of Liberty's investment to serve iNATGAS, because the project has the potential to provide net benefits to rate payers, over time, depending on the CNG market. Staff maintained that Liberty knew, or should have known, that its cost estimates were too low and that had more accurate estimates of costs and revenues been presented in DG 14-091, Staff might not have recommended approval of the special contract. Exh. 56 at 19-25.

Staff asserted that because the Accelerated Sales Assumption Level has the same maximum annual sales volumes as the Baseline Assumption Scenario, even the baseline scenario could not have been met using the investment figures that were presented in DG 14-091. 3/22/18 PM, Tr. at 97-100. Staff also noted that two of the three revenue scenarios presented could not have been achieved with the level of investment reflected in the analysis, and that the one remaining analysis shows a negative NPV over 15 years when AFUDC, a real cost of the project, is included in the analysis. Exh. 46 at 2.

Staff questioned Liberty's assertion that the arrangement provides benefits to existing firm customers in the form of interstate pipeline capacity credits, based on iNATGAS's peak day load. Staff noted that if additional capacity has to be acquired to serve iNATGAS, the cost of that capacity could exceed iNATGAS capacity credits. Staff did not request a full denial of cost recovery of Liberty's investment to serve iNATGAS, because the project has the potential to provide net benefits to rate payers, over time, depending on the CNG market.

Ruling. The record demonstrates that Liberty's initial analysis of its investment of $2,245,000 was incomplete. That analysis formed the basis of senior management's approval of the project. Exh. 43 at 2-5. First, the initial cost estimate of $2,245,000 did not include AFUDC, although Liberty agreed that AFUDC would be incurred if the project were completed, 3/6/18 PM, Tr. at 108, and it is indisputable that AFUDC could be substantial if the project timeline were extended. Ultimately, AFUDC on this project totaled $436,000.

Second, Liberty's cost estimate included only $865,000 for "piping, meter set, survey, etc." Because the only other costs estimated were $1,000,000 for compressors, $200,000 for land, and $180,000 for contingencies, it is reasonable to conclude that the "piping, meter set, survey, etc." category was intended to cover all other costs of the project (except AFUDC). Liberty was not able to break down the $865,000 among piping, meter set, and other items, beyond noting that the figure would have included surveying, tree removal, more than half of the asphalt and concrete ultimately installed, pump canopies, the connection of the compressors, and perhaps additional items. 3/14/18 PM, Tr. at 30-33. Liberty stated that 4 or 6 inch steel piping was installed with a maximum allowable operating pressure of 750 pounds per square inch. *Id.*

at 34. Liberty also stated that the labor involved in installing the compressors was not included in the compressor figure of $1,000,000. *Id.* at 29. When the actual figures were reviewed, the items that were projected at $865,000 actually cost $3,080,000, an almost fourfold increase. *Id.* at 32.

The first major driver of the increase was the decision to construct a full capacity facility instead of a phased facility, as had been planned and presented to the Commission for review in DG 14-091. Liberty, at a cost of $600,000 to $700,000, accelerated the buildout due to anticipated increased demand, high spot market natural gas prices, and high oil and propane prices following the very cold winter of 2014/2015. Exh. 24 at 68-71. Liberty stated that the additional investments were needed to build the facility necessary to reach the Accelerated Sales Assumption Level presented to the Commission in DG 14-091. *Id.* Exh. 38 at 2. Liberty agreed that the cost of the full buildout should have been included in the 2014 NPV analysis, in order for the accelerated sales scenario to be accurate. 3/14/18 PM, Tr. at 13. Second, Liberty attributed $600,000 of the cost increases to requirements placed by the City to repave Broken Bridge Road and to install a new water main for 2,500 feet. Liberty knew of the City's requirements in mid-June 2014, well before the Commission order approving the special contract was issued on July 15, 2014, yet no update of the DCF analysis was provided to the Commission to reflect this $600,000 cost increase. 3/14/18 PM, Tr. at 41. Third, Liberty attributed $835,000 of the cost increase to design changes involving additional canopies and buildings to protect the various pieces of equipment from weather, and moving the meter closer to the interstate pipeline and further from the CNG facility. Liberty did not explain why those design changes were made after the Commission reviewed the special contract, rather than before. 3/14/18 PM, Tr. at 76-77.

We find it troubling that the analysis Liberty presented to us in 2014, under a request for fast track review of the proposed special contract (3/22/18 AM, Tr. at 27-28) omitted so much material cost information. The fact that this same analysis was also presented to senior management for review and approval of the project brings into question the prudence of Liberty's decision to proceed with the project. Again, prudence is judged on what a reasonable utility executive knew or reasonably should have known when making a decision.

The record demonstrates that the 2014 DCF analysis was flawed and that many costs were missed or underestimated. Including revenues from sales scenarios, while omitting the investment needed to realize those revenues, is a serious mistake. Liberty's inability to breakdown its estimate of "piping, meter set, survey, etc." into its component parts is not acceptable. The notion that the "etc." in this lump sum figure was sufficient to cover tree removal, asphalt, concrete, canopies, and the labor needed to connect the compressors is not credible. A reasonable utility executive being asked to sign off on the $2 million-plus venture would have, or should have, required more detail.

Further, it appears that follow-up review of this project was minimal and was not performed early enough to be of any use. The record contains an Over Expenditure Application dated March 2016 that shows updated costs and updated payback and internal rate of return analyses. That application states that Liberty had already spent 70 percent of required project costs when the report was provided to management. Liberty knew about the municipal requirement for street work and water main extensions totaling $600,000 (25 percent of the total projected cost) in June 2014, almost two years earlier. Liberty should have re-examined the project in 2014.

Liberty was on notice in DG 14-091 that its investments in the project would be subject to prudence review in a future rate case. Exh. 56 at 19. This case, however, was filed with little detail about the iNATGAS investment.

Full exclusion of the cost of the facility would be justified under a strict prudence examination, which focuses on the facts that were known or should have been known at the time of the decision to undertake the project. That said, we are mindful that the iNATGAS facility, like the training center, is in service and appears to be used and useful. In addition, the iNATGAS facility has the potential to provide net benefits to customers in the future, and therefore a complete exclusion of recovery may not be the best overall remedy.

Liberty testified that the winter 2017/2018 revenues were approaching the baseline scenario. 3/14/18 PM, Tr. at 60. Under the baseline scenario, using $4.8 million, the actual costs of the facility, including AFUDC, a NPV of $2.9 million is projected to be returned to customers through base rates over the 15-year study period. Exh. 46 at 2; 3/14/18 PM, Tr. at 4-5. Liberty testified that those projections would be higher if the scenario were re-calculated using updated tax rates and return on equity percentages. 3/14/18 PM, Tr. at 7-8. Liberty also stated that pipeline capacity cost savings will accrue from the project and those savings were not included in the NPV analyses. Exh. 24 at 71-72. The Commission approved the special contract when it was presented as a $2,245,000 investment with $4,732,000 projected to be returned to firm customers through base rates, under a baseline revenue scenario. Exh. 38 at 2. It is doubtful that we would have approved a $4.8 million investment to return $2.9 million to firm customers over 15 years, if we had been presented with such a scenario.

Nevertheless, the plant has been built and, for purposes of the base rates set in this case, we will allow recovery of the plant up to the level of costs presented in DG 14-091 ($2,245,000) plus related O&M expense. We will re-evaluate this investment in Liberty's next rate case and may consider putting more of the investment in rate base at that time. The remedy fashioned here will put ratepayers in the position they were in when this project was approved. Accordingly, we adopt Staff's proposed adjustment.

K. Keene Division Matters

Liberty. In its initial rate case filing, Liberty, proposed that the Keene Division distribution rates be consolidated into the general EnergyNorth distribution rates applicable throughout the sState, pointing out there is no material difference between distribution service to its customers in Keene and elsewhere. Exh. 3 at 22-23. Liberty calculated the revenue deficiency for the Keene Division during the test year to be $712,403. In support of its request, Liberty said consolidation would limit rate case expenses and administrative costs for the Keene Division's small customer base of approximately 1,200 customers. Exh. 3 at 22-23.

The revenue deficiency included a three-year amortization of $201,000 of emergency response costs related to a December 2015 incident at the propane-air plant[1] and $148,410 of production costs that were formally recognized in the Cost of Gas. Exh. 3 at 26 and 63. Liberty proposed maintaining a separate Keene Division Cost of Gas (COG) ratemaking structure, even with the planned conversion to a Compressed Natural Gas/Liquefied Natural Gas (CNG/LNG) fuel structure for the Division. *Id.* at 23-24.

In its rebuttal testimony, Exh. 24, the Company provided additional arguments in support of its concept of rate consolidation for the Keene Division. Liberty opposed Staff's contention, discussed below, that significant cost-shifting would result from rate consolidation, with Liberty

[1] The December 2015 Keene incident involved a failure of the blower system at the Keene production plant that caused the release of carbon monoxide and unburned propane, and necessitated shutdown of the Keene system. The emergency response personnel directed by the City of Keene assisted Liberty in visiting each home to check on occupants and re-light appliances. *See* 3/27/18 Tr. at 119-123.

pointing to an expected monthly bill impact on general Liberty residential distribution rate customers of 37 cents assuming a revenue requirement of $14.7 million. Exh. 24A at 49-50. In response to questioning about the settlement agreement, Mr. Hall testified the monthly impact on general Liberty residential customers would be 26 cents based on the agreed revenue requirement of $10.3 million. 3/21/18, Tr. at 197.

Liberty also pointed to what, in its view, were similar instances of Commission approval of inter-divisional rate consolidations. Exh. 24 at 51. Liberty argued that, in all likelihood, failure to consolidate rates would result in a failure to expand its system, due to Liberty and customer uncertainties regarding the likely costs of expanded service. Eventually, the Keene system would have to be abandoned, due to rate shocks related to Keene-specific distribution revenue requirement shortfalls. Liberty stated that current efforts to convert a small portion of the Keene system to CNG were being done for safety and reliability and to avoid the need for 24-hour coverage at the propane-air plant during the winter months, and is not being done for rate consolidation purposes, nor for growth, although the conversion could lead to additional growth. *Id.* at 52-62. Liberty also presented certain data request responses, schematics, and schedules that delineated Liberty's planned multi-phase approach to distribution-system expansion for Keene. *See* Exh. 24, 73-91.

In its closing statement, Liberty argued that response costs for the December 2015 incident were reasonable and required under RSA 154:8-a. Following the 2015 incident, Liberty decided that the risk of an extreme event was still possible, although unlikely, which justified the 24-7 manned coverage during the winter months. *See* 3/27/18 Tr. at 119-123.

Liberty supported the provisions of its settlement agreement with the OCA pertaining to the Keene Division (discussed below). Liberty also expanded on its points in favor of rate consolidation presented in its direct and rebuttal testimony through oral testimony at hearing. *See* 3/27/18 Tr. at 114-123; *see also* 3/21/18 Tr. at 141-207.

OCA. The OCA's original position was that consolidation at this time was not appropriate, and that revenues associated with the Keene Division should be dealt with in a separate docket.

Settlement. Liberty and the OCA agreed in their settlement that the emergency response costs related to the December 2015 incident and the Keene production costs should be recovered through the Keene Division COG rates over five years during the Keene Division COG winter period, and beginning November 1, 2018. Exh. 29 at 7. They also agreed that Keene Division customers would pay the same distribution rates and be served under the same terms and conditions as all other Liberty customers, effective May 1, 2018. *Id.* at 12.

Under the terms of the settlement agreement, Liberty also agreed to a target amount of additional revenue due to growth in excess of the revenue requirement associated with the direct cost of the investment; if the cumulative excess revenue is less than $200,000 annually, Liberty would reduce its revenue requirement in its next rate case by the difference between $200,000 and the excess revenue. "Excess revenue" would be based on actual load added as of the effective date of permanent rates following the end of the next rate case, plus reasonable anticipated revenue based on customer commitments to take service, both pro-formed for one year following the effective date of permanent rates in the next rate case. This provision was conditioned on Liberty's receipt of the Safety Division's authorization to commence construction of Phase 1 no later than May 1, 2018, and on acquiring appropriate authorization to construct a permanent CNG/LNG facility by May 1, 2019. *Id.* at 12-13. The settlement agreement also specified that Keene customers would begin paying the LDAC as of May 1, 2018, and that the

Keene Division would continue having a separate COG, which would include: (1) propane purchases; (2) CNG/LNG purchases; (3) production costs; (4) revenue requirement associated with CNG/LNG facilities; and (5) revenue requirement associated with fuel inventory. *Id.* at 13.

Staff. Staff opposed the consolidation of the Keene Division's distribution rates with those of EnergyNorth. Exh. 56 at 5. Staff argued that "[c]onsolidating rates at this time will result in cost shifting and cause financial harm to [EnergyNorth's] ratepayers through higher rates to subsidize the Keene [Division] operations." *Id.* Staff agreed with Liberty that the Keene Division does not collect enough revenue to cover its costs, but opposed the approach of rate consolidation as the appropriate remedy.

Staff argued that the order approving the acquisition of the Keene Division in Docket No. DG 14-155 established a "no net harm test" that militates against uneconomic cost shifts resulting from rate consolidation. Exh. 56 at 9, 14-15. Staff argued that such harm to EnergyNorth customers would indeed occur if consolidation were to be approved. *Id.* As the appropriate remedy, Staff recommended that Liberty should either file a separate Keene Division rate filing requesting a distribution rate increase for the Division; a rate plan that would lead to consolidated rates based on a comprehensive business plan and financial analysis that demonstrates a quantifiable benefit for all Liberty customers, or at the very least no net harm; or to discontinue service by demonstrating that continued service can only be provided at a loss and that Keene Division customers can be conveniently converted to an alternate fuel source and utility plant safely abandoned. *Id.* at 9-10.

Staff noted in its testimony that Liberty failed to provide a comprehensive business plan for its originally 4-phased planned expansion for the Keene Division system. The Discounted Cash Flow (DCF) analysis provided during discovery by Liberty fell far short, in Staff's view, of a comprehensive business plan, and provided little or no support regarding the cost and revenue projections used in the DCF analysis. *Id.* at 10. In particular, Staff pointed out that the Liberty DCF analysis for Phase 1 of the planned Keene Division expansion did not include the $418,384 cost of land (for the planned CNG/LNG production facility) that is currently classified as "Property Held For Future Use" and is therefore not eligible for rate recovery. According to Staff, the Phase 1 planned expansion makes use of that land. The land would become used and useful when placed into service and should be included as a conversion cost. *Id.* Staff concluded that, for the Keene Division, Liberty planned to undertake a CNG/LNG conversion and expansion intended to increase capacity and lower rates, but Liberty's filing provided no details as to whether, or how, that conversion/expansion effort would impact the cost to serve Keene and if the Keene Division customer base can support that cost. *Id.* at 11.

Staff raised concerns regarding certain categories of costs that Liberty included in its calculation of the Keene Division revenue deficiency for the test year. Specifically, Staff alleged that Liberty included costs that were outside the test year, and may not have been prudently incurred. Staff noted that it filed a memorandum in Docket No. DG 16-812, the Keene Division 2016-2017 Winter COG proceeding, recommending that certain Keene propane-air gas production costs not be recovered through COG rates, because production costs are reflected in Keene Division's delivery rates, and the costs of manning the Keene production plant on a 24-7 basis may have been imprudent, in Staff's view. *Id.* at 11-13; 35-43. Staff also raised concerns about the appropriateness for recovery, through Liberty's calculated Keene Division revenue requirement, of personnel costs arising from the December 2015 incident.

Staff also concurred, to a certain extent, with Liberty's assessment of a potential "death spiral" if the calculated Keene Division revenue deficiency were recovered solely from Keene

Division customers, which would drive an adverse rate impact. As noted, however, Staff did not endorse the approach of rate consolidation as proposed by Liberty to ameliorate this problem. Exh. 56 at

14-15; *See also* 3/22/18 AM, Tr. at 42-59; 3/27/18 Tr. at 71-75

Ruling. Unreasonable cross-subsidization of expansionary business by an existing utility, or of one class or locality of utility customers by the general customer base of a utility, is to be avoided. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 26,109 at 15-22 (March 5, 2018); *In re: Concord Steam Corporation Non-Governmental Customers*, Order No. 26,017 at 11-12 (May 11, 2017); *see also C. Julian Tuthill El Al. v. Plaistow Electric Light & Power Company*, 8 N.H.P.S.C. 509, 510 (1922). This precedent is undergirded by RSA 378:10, "[n]o public utility shall make or give any undue or unreasonable preference or advantage to any person or corporation, or to any locality, or to any particular description of service in any respect whatever or subject any particular person or corporation or locality, or any particular description of service, to any undue or unreasonable prejudice or disadvantage in any respect whatever." On the other hand, under RSA 378:11, "The provisions of RSA 378:10 shall not require absolute uniformity in the charges made and demanded by public utilities when the circumstances render any lack of uniformity reasonable." The Commission has discretion in balancing the need for fairness in avoiding cross-subsidization with ensuring the overall public interest.

In this instance, evidence has been presented that, barring consolidation of the Keene Division's distribution rates with those of EnergyNorth, the Keene Division's rates will begin to escalate and make service in the City of Keene increasingly uneconomic. Furthermore, Liberty made an argument that any expansion of gas service in the City of Keene, utilizing new

CNG/LNG installations and associated distribution lines, will not be feasible if consolidation of distribution rates is not allowed. Further, there is evidence that consolidation will reduce administrative costs and provide an opportunity for revenue growth in Keene that, if successful, will benefit all Liberty customers. We are persuaded that there will not be an unreasonable cost-shifting by consolidating Keene with EnergyNorth's distribution customers. Such consolidation is consistent with precedent where other smaller utilities acquired by larger utilities are consolidated. *See, e.g., Pennichuck Waterworks Inc.*, Order No. 22,883 (March 25, 1998) (Commission determined an increase of $1.00 a month to Pennichuck's Nashua customers was not unreasonable as part of rate consolidation with smaller companies).

Moreover, we see little difference between consolidating the Keene Division and adding a new franchise territory like Hanover and Lebanon which we have authorized to be included in Liberty's general distribution rates under certain conditions. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 26,109 (March 5, 2018). We note Liberty's testimony that "prior to completing the business plan, [Liberty] will need to perform a detailed engineering design for the distribution system and supply facility that will be used to plan the construction and expansion of the system." Exh. 24 at 59. Given the unknowns regarding the economic viability and cost structure of Liberty's Keene Division expansion plans, we will apply the risk-sharing provisions imposed on Liberty within the context of its Hanover and Lebanon CNG/LNG expansion effort outlined in Order No. 26,109. We apply those more robust provisions, with some modification, in preference to the settlement agreement's provisions.

Therefore, we will permit the consolidation of Keene Division distribution rates with those of EnergyNorth, subject to the following conditions designed to protect EnergyNorth's distribution customers from potential over- capitalization that could lead to cross subsidization (Keene Division COG rates will remain a separate ratemaking structure):

1. For any of the expansionary Phases planned by Liberty within the City of Keene, prior to beginning construction of any Phase, Liberty must secure a customer commitment level that will produce at least 50 percent of the revenue requirement associated with the new facilities from those customers in 10 years, as calculated in present value terms;

2. Liberty must reduce its revenue requirement by 50 percent of any revenue shortfall in the first distribution rate case filed within five years following construction of each Phase and by 100 percent of any revenue shortfall in the second distribution rate case filed within the five years following the construction of each Phase;

3. In the case of Keene, the revenue requirement to be considered in this analysis would include both production costs and distribution costs, with production costs recovered in the separate Keene COG rate to be applied to Keene customers including the cost of land on which the new Keene CNG/LNG production plant is located, the cost of the current effort to convert a small portion of the system to CNG, the direct costs of the production facilities, propane purchases, CNG/LNG purchases, the revenue requirement associated with CNG/LNG facilities, and the revenue requirement associated with fuel inventory;

4. The direct cost of the Keene distribution system is to be recovered through Liberty distribution rates applicable to all Liberty distribution rate customers;

5. Customer commitment requirements apply to the revenue requirement reflected in both the Keene COG and Liberty distribution rates. Revenue reductions under the risk-sharing conditions set forth in this order will apply to both the Keene COG and Liberty distribution rates based on the Keene investment costs reflected in each;

6. Liberty will file updated DCF analyses at the in-service date of each of the Phases of the Keene expansion project, and annually thereafter, until ordered otherwise. The initial and annual reports will include the following:

i. A comparison of the original and updated DCF analyses;

ii. A comparison of the original annual projected residential and C&I customer conversions and gross profit margins, by fuel type, with the actual annual conversions and gross profit margin; and

iii. A Current Heating Fuel Value table comparing the annual average residential heating rate calculated using the Keene Division bill impact schedule in its COG filing and the cost of alternative fuels in effect at the time as reported by the New Hampshire Office of Strategic Initiatives.

7. Liberty's obligation to meet, pursuant to RSA 374:1, 374:3, and 374:4, the inspectional and operational requirements of the Commission's Safety Division, and to satisfy the Safety Division regarding those requirements, remains in place indefinitely. *See* Order No. 26,065 (October 20, 2017);

8. The risk-sharing condition we impose will terminate following the date on which Keene customers have produced at least 100 percent of the revenue requirement associated with the new facilities for each phase, provided Liberty petitions the Commission to terminate the applicable risk-sharing provision and submits the necessary documentation to demonstrate that the condition for termination has been met.

With respect to the December 2015 incident, we find that the emergency response costs of $201,000 were prudently incurred, and that amortizing recovery of those costs over three years is reasonable.

As for the Keene production costs of $148,410, we find that Liberty failed to justify those costs in this proceeding. Liberty made many significant enhancements to address the risk of a similar event and did not provide evidence that the incremental costs of manning the plant were reasonable or justified. Accordingly, we deny recovery of those costs.

Because we find around-the-clock staffing of the Keene production plant is not just and reasonable, we reject the Company's argument that the current cost of converting a small portion of the Keene system to CNG is necessary for reliability and safety reasons or is economically justified on its own terms. Furthermore, Liberty testified that the conversion could lead to additional growth, and it is therefore appropriate to include the cost of the initial conversion to CNG in the risk sharing mechanism delineated above.

L. Cost of Capital

Liberty. In its initial filing in this matter, Liberty proposed rates based on a weighted average cost of capital (WACC) of 7.36 percent which included a return on equity (ROE) of 10.30 percent and a capital structure consisting of 50 percent common equity and 50 percent long-term debt. Exh. 3 at 69. Liberty did not revise its position in its rebuttal testimony filed in January 2018. Exh. 23 at 26.

OCA. In its initial filing in this case, the OCA recommended a WACC of 6.41 percent, calculated using an ROE of 8.4 percent. Exh. 16 at 238; Exh. 15 at 195.

Settlement. In the settlement, Liberty and the OCA agreed to a WACC of 6.85 percent, an ROE of 9.4 percent, and a capital structure consisting of 49.21 percent common stock, 49.85 percent long-term debt, and 0.95 percent short-term debt. Exh. 29 at 4. The settlement states that this capital structure reflects recently approved long- and short-term debt changes. *Id.* at 3.

Staff. Staff proposed that rates be calculated using a WACC of 6.42 percent, which included an ROE of 8.55 percent and a capital structure consisting of 49.21 percent common equity, 49.85 percent long-term debt, and 0.95 percent short-term debt. Exh. 20 at 77. Staff later agreed that the settlement ROE of 9.4 percent and settlement WACC of 6.85 percent were reasonable for setting rates in this case. 3/6/18 AM, Tr. at 11-12.

Ruling. In light of agreement among Liberty, the OCA, and Staff (parties with strongly different views on many aspects of this rate case), we find the WACC of 6.85 percent and the ROE of 9.4 percent reasonable with one important change. We are approving a decoupling mechanism in this case, which reduces the risk that Liberty will not recover its authorized revenue requirement. In addition, the stabilized cash flow should improve the Company's credit rating and thus its access to lower cost debt.

We reject Liberty's claim that its reduced risk associated with decoupling is already reflected in its recommended ROE (and therefore, presumably, the settlement ROE). Liberty claims that the proxy group of utilities Liberty used to determine its requested ROE already had decoupling. In drawing this conclusion, Liberty does not differentiate between straight fixed-variable rate design, LRAMs, and a weather normalization clause. Instead, Liberty lumps them all under the heading of "decoupling" and states that the proxy group already reflects decoupling. The Commission does not consider rate designs and LRAMs to be comparable to the decoupling provision approved herein in terms of risk of recovery of costs, primarily because the decoupling mechanism we adopt will shield Liberty from swings in weather while rate design changes and LRAMs are unrelated to and unaffected by weather. Most of the companies with decoupling do not include monthly weather normalization.

Accordingly, to account for the decrease in risk Liberty will experience under the approved decoupling mechanism, we will set the ROE in this case at 9.3 percent, resulting in a WACC of 6.8 percent. That ROE is 10 basis points lower than the ROE contained in the settlement.

M. <u>Decoupling</u>

Liberty. Liberty proposed what it termed a full decoupling mechanism, based on revenues per customer. The mechanism was designed to sever the link between Liberty sales and revenues to remove the Company's disincentive to promote energy conservation that is inherent in traditional ratemaking. Liberty's distribution revenue per customer targets would be set based on test year information and then, going forward, rates would be adjusted twice annually (up or down) to allow the Company to collect its target revenue, calculated using actual customer counts. By using a revenue-per-customer mechanism, Liberty has an incentive to add customers and to control costs. The mechanism would shield Liberty from changes in sales due to conservation (both utility sponsored and other) as well as weather swings and economic factors. Exh. 8 at 282-290.

Liberty proposed that the decoupling mechanism be administered to three groups of customers: residential non-heat, residential heat, and all C&I. *Id.* at 320. Liberty also proposed an annual 5 percent cap (based on distribution revenues) on any one adjustment, with provisions for collecting adjustments that went beyond the 5 percent cap. *Id.* at 324. In rebuttal testimony, Liberty proposed administering the mechanism at the rate class level, rather than the three groups identified in its original proposal. Exh. 27 at 178.

OCA. The OCA originally proposed a decoupling mechanism calculated at the total company revenue level (in contrast to Liberty's proposal of a revenue per customer mechanism) that would incorporate weighted historic weather data where more recent years are given more weight. The OCA proposed that decoupling be implemented on what it characterized as a "real-time" basis to improve customer and company cash flows and so that customers see the impact of weather on the bills as it is experienced. The OCA calculated that under its proposed decoupling mechanism, customers would pay significantly less than under the currently approved LRAM, based on recent historical sales (and reflecting recent actual weather). Exh. 14 at 10-22.

Settlement. The settlement decoupling mechanism combined Liberty's revenue per customer target approach with the OCA's monthly weather adjustment. The settlement decoupling mechanism calls for annual adjustments for any additional differences between target and actual revenues per customer (i.e., those not related to weather) calculated for two groups – residential customers and C&I customers. The decoupling mechanism would begin November 1, 2018, at which time Liberty would cease collecting lost revenues attributable to energy efficiency programs, currently collected through a lost revenue adjustment mechanism (LRAM). The settlement also allows Liberty to recover up to $50,000 in costs incurred to upgrade its billing system and related software to implement decoupling. Exh. 29 at 10-12.

Staff. Staff proposed a decoupling mechanism similar to what Liberty initially proposed, but without a weather component. Staff supported adjusting revenues once per year to account for reduced sales from energy efficiency and all other factors, except weather. Staff stated that utilities have always borne the risk and reward for sales deviations due to weather swings and that this risk is unrelated to energy efficiency. Staff proposed that the decoupling adjustment be calculated by rate class. Exh. 18 at 10-14. Staff opposed the settlement decoupling proposal because shielding Liberty from weather impacts was not a stated goal of the Commission's recently adopted Energy Efficiency Resource Standard (EERS) and is unrelated to energy efficiency. Staff believed that the bill credits customers would receive in cold months, when they presumably used more gas, would send anti-conservation price signals. Further, Staff said the administration of the monthly weather adjustment would be complicated and the results would be difficult to audit. 3/26/18 AM, Tr. at 9.

Ruling. All participants in the case propose decoupling mechanisms. Except for the issue of weather, we see little significant difference between the various decoupling mechanisms proposed. Traditionally, gas utility rates are set assuming normal weather and any fluctuations in revenues due to abnormal weather are absorbed by the Company until its next rate case.

The Commission's order in the EERS docket set the stage for utilities to propose decoupling mechanisms to replace the LRAM. The LRAM was intended to be a temporary measure to remove the disincentive for utilities to undertake energy efficiency programs. We applaud Liberty for proposing a decoupling mechanism to replace the LRAM.

We acknowledge the Company's and the OCA's strong support for monthly weather normalization and agree that it would stabilize cash flow for Liberty. We note Staff's point that providing customers a small distribution rate reduction in a month where cold weather causes them to use more gas may send a small counter-intuitive price signal. We are persuaded, however, that the impact will be significantly diminished by the fact that customers' bills in total will be higher during colder months than during warmer months, even with this adjustment, which only affects one portion of the customer's bill.

Accordingly, we approve the settlement decoupling proposal in concept. We also provide the following for clarity and to facilitate implementation. Decoupling may not be used to compensate Liberty for revenue lost due to reduced customer counts. Because decoupling is slated for November 1, Liberty is directed to file within 45 days of this order illustrative tariffs demonstrating the rates, terms, and conditions required to implement decoupling in conformance with existing law. Due to the novelty of the decoupling process in New Hampshire, Liberty must also submit at the same time customer notice and educational materials for review and approval by the Commission.

The settlement would have required Liberty to file its next rate case using an historic test year no later than December 31, 2020, to reset test year revenues in light of the decoupling mechanism. 3/6/18 AM, Tr. at 57. We agree that such a reset is well advised and we adopt such a requirement in this order. Further, to assist the Commission in evaluating Liberty's decoupling, we require the Company to report in its next rate case on the following: (1) the amount of revenue collected or passed back through this mechanism, by year; (2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs; (3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes; (4) an account of efforts taken to educate builders about energy efficiency; (5) a detailed list of meetings with state and local officials and associations to promote energy efficiency; (6) customer feedback resulting from decoupling as implemented through the rate design; and (7) any changes in the Company's credit rating.

The above list is not intended to be exhaustive. In short, we require the Company to demonstrate that decoupling has allowed the Company to "remain an effective champion of energy efficiency" and has unlocked its "ability to enthusiastically support energy efficiency policy goals." Exh. 8 at 282, 286.

N. Rate Design

Liberty. In its original filing, Liberty proposed significant increases to all its customer charges, based on the results of its marginal cost study and bill impact considerations. Under the proposal, a residential non-heating customer (R-1) would see a 40.8 percent customer charge increase ($6.23 per month) as part of a plan to increase customer charges over three rate cases. Residential heating customers (R-3) and residential low income customers (R-4) would see 15.4 percent increases ($3.40 per month). Commercial and Industrial customer charge increases were based on considerations of marginal costs, rate continuity and customer impacts. Proposed C&I increases were: for rate classes G-41 and G-51 (low annual use customers) 15 percent and for rate classes G-42, G-43, G-53 and G-54 (medium and high annual use customers) 10 percent. Exh. 7 at 210-213. Concerning volumetric rates, Liberty proposed to continue its current use of declining block rates for all classes. *Id.* at 213-214.

OCA. The OCA originally proposed reducing customer charges for all classes and flattening, or eliminating, any existing declining rate block structures. Exh. 14 at 106.

Settlement. The rates in the settlement are significantly different than the rates in Liberty's initial proposal. Customer charges for residential non-heating and heating customers would be set at $14.88 per month, which is $2.00 lower than the current R-1 amount and more than $9.00 lower than the current R-3 charge. For R-3 customers, the head and tail block volumetric rates would be set at the same level. R-4 rates would be set at 40 percent of the R-3 rates. All C&I rate components would be increased proportionally. Exh. 29 at 10 and 25. The OCA supported the settlement rate design because it would promote energy efficiency.

Staff. Staff did not recommend changes to Liberty's proposed customer charges. Staff proposed to set the head and tail blocks at the same level and to allocate any decoupling refunds to the head block and any decoupling surcharges to the tail block. Staff proposed this approach for all rate classes to promote energy conservation, because under decoupling, Liberty has an enhanced opportunity to recover its fixed costs. Exh. 18 at 16-18.

Ruling. Given that we approve the settlement decoupling mechanism, it follows that we approve the settlement rate design. We agree with Staff that decoupling greatly increases the Company's ability to recover its fixed costs and therefore, we are comfortable with the significant decreases to the residential customer charges contained in the settlement. Similarly, we support the flat rate block structure for residential customers, which we agree should encourage conservation. Accordingly, we approve the settlement rate design.

O. Tax Act Impacts

During the course of this proceeding, the federal Tax Cuts and Jobs Act of 2017 (2017 Tax Act) was enacted, effective for tax year 2018. The 2017 Tax Act reduced the corporate income tax rate from 35 percent to 21 percent, which reduces a utility's required annual revenues. On January 3, 2018, the Commission opened Docket No. IR 18-001 to investigate how the 2017 Tax Act will affect the expenses of New Hampshire public utilities. *See Investigation to Determine Rate Effects of Federal and State Corporate Tax Reductions,* Order No. 26,096 (January 3, 2018)[2].

The settlement filed in this case calculated the revenue requirement effect of the 2017 Tax Act as $2,394,065, which would have been subtracted from the settlement agreement revenue deficiency of $10.3 million. Exh. 29 at 23. Staff questioned Liberty's methodology and thus, the accuracy of this figure. Recognizing that the Commission would be reviewing the impact of the 2017 Tax Act in a separate investigation, for purposes of this case, Liberty, Staff,

[2] In Order 26,096, the Commission also ordered an investigation of the impacts of the reductions to the New Hampshire Business Enterprise Tax and the Business Profits Tax.

and the OCA agreed that this figure of $2,394,065 should be subtracted from the revenue deficiency ultimately approved in this case. The adjustment may be subject to further adjustment pending the outcome of the separate tax investigation. 3/21/18 PM, Tr. at 45-52.

Ruling. The Commission adopts this approach as reasonable and will use a separate docket to refine the figure of $2,394,065 and make rate adjustments accordingly. In addition, because the final rates will be reconciled back to the effective date of the temporary rates granted in this docket (July 1, 2017), and the difference will be recouped, the recoupment calculation will need to address the difference in the tax rates in 2017 and 2018. Reconciliation of any differences will be addressed in the separate docket established to deal with tax adjustments.

P. <u>Residential Low Income Assistance Program</u>

Liberty. Liberty did not propose a change to the Residential Low Income Assistance Program (RLIAP) in this docket. In response to Staff's proposed change, Liberty stated that any changes to the program should be addressed in a generic docket where the other affected New Hampshire utilities could be involved, so that any changes would be uniform across the utilities.

OCA. The OCA took no position on the RLIAP.

Settlement. The settlement states that the Commission should open a generic docket to address changes to the RLIAP. Exh. 29 at 14.

Staff. Staff recommended that the RLIAP be restructured so that the discount would be calculated on a residential customer's total bill, rather than the base rate portion of the bill as it is currently done. Staff recommended the change so that the discount offered to participants would be closer to the program goals established by the Commission. Staff stated that the change was needed because the base rate portion of a customer's gas bill has increased in recent years while the cost of gas potion has decreased, and thus the total discounts given were trending higher than planned. Exh. 56 at 25-29.

Ruling. We decline to make any changes to the RLIAP in this case and will open a separate docket to consider changes to the RLIAP.

Q. Step Adjustment

Liberty. Liberty proposed one step adjustment effective May 1, 2018, to recover the costs associated with plant investments made during 2017. It sought an increase in base rates of $5,921,000 for the EnergyNorth division, based on $41,438,000 of plant investments, and $151,000 for Keene division investments of $745,000. Exh. 3 at 28-29 and 76-77.

Liberty updated the proposed step adjustment in its rebuttal testimony, where the step increase in rates would recover $5,095,000 on plant investments of $27,465,000, covering both the EnergyNorth and Keene Divisions. Exh. 23 at 39. This figure represents estimated investments for 2017. Liberty proposed to update this figure to reflect actual investments. The amount of $5,095,000 would act as a cap on the proposed step adjustment. The $5,095,000 amount in the rebuttal testimony also reflected an additional $419,600 in O&M expenses related to pension and benefit costs that had previously been capitalized and now needed to be charged to expense due to Financial Accounting Standard (FAS) Update No. 2017-17. Exh. 23 at 22. Liberty stated that it estimated the FAS 2017-17 effect based on 2017 actuarial assumptions and capitalization percentages. *Id.* The figure also included $173,000 in legal fees incurred in 2017 in connection with litigation Liberty undertook in an effort to reduce fees charged by the cities of Concord and Manchester for claimed road degradation, as well as $186,000 in degradation fees incurred during 2017. *Id.* at 39.

OCA. The OCA took no position on the step adjustment.

Settlement. The settlement agreement contained a step adjustment equal to $5,044,835 based on plant investments of $27,955,000 and the same pension/benefit costs, legal fees and degradation fees as the rebuttal testimony. Exh. 29 at 18.

Staff. Staff supported the step adjustment in concept but raised two issues. First, Staff stated that the pension/benefits amount should be updated for 2018 actuarial assumptions when available. 3/6/18 AM, Tr. at 13. Second, Staff disagreed with the inclusion of the full amount of the 2017 legal fees and degradation fees in the step increase and instead recommended that legal fees be amortized over three years, and degradation fees be amortized over 20 years. Exh. 54; 3/21/18 Tr. at 67-76, 137-139.

Ruling. Based on the agreement of the parties, we approve a step increase effective May 1, 2018, estimated at $4,729,953 and limited to $5,044, 835, and reflecting pension and benefit numbers using the latest available actuarial information. Regarding amortization of legal fees and degradation fees, we agree with Staff that to include the full 2017 amount for those items in permanent rates would mean that customers would be paying that full amount each year. We find that a three-year amortization of legal fees and a 20-year amortization of degradation fees is consistent with how Liberty originally proposed to treat those test year costs, is more reflective of what customers would pay in a single year, and is thus more appropriate.

R. <u>Recoupment</u>

The Commission approved a temporary rate increase effective July 1, 2017, in the amount of $6,750,000. The permanent rate increase of $8,060,117 approved in this order is to be effective as of May 1, 2018. Pursuant to RSA 378:29, Liberty may collect an amount equal to what would have been collected if the permanent rate increase had been effect during the temporary rate period. For clarity, the step increase is not reconciled with temporary rates and is effective May 1, 2018.

The settlement includes a recoupment calculation using the settlement revenue deficiency of $10.3 million and provides for collection through the LDAC, with reconciliation. Exh. 29 at 9, 20. We adopt that calculation and recovery method, but modify the amounts for the revenue deficiency approved herein of $8,060,117. *See* Appendix 5 to this Order.

S. Rate Case Expenses

We will provide for the recovery of just and reasonable rate case expenses through the LDAC, using the method outlined in the settlement. Exh. 29 at 9-10. Those costs are currently estimated to be $530,000, subject to review and approval. *Id.* at 22.

V. CONCLUSION

As we observed above, this is an unusual situation. Under New Hampshire law, the rates originally proposed by Liberty were suspended until April 28, 2018, while we investigated the request. Liberty and the OCA reached an agreement that would have resolved all of the issues in the case, but Staff did not join the settlement. Therefore, at the hearing on the merits, Liberty presented neither its full original case, nor its rebuttal position, except as a way to argue for the reasonableness of the settlement. That approach made sense in the context of the hearing, as the settlement did not itemize adjustments to Liberty's original request to arrive at the agreed-upon revenue deficiency. Instead, the "compromise" total revenue figure reflected, in Liberty's view, allowances for the contrary positions taken by the OCA and Staff in their original submissions.

Our choices, therefore, are that we could approve the settlement, accept Liberty's rate request, or set rates based on the record. Given that reality and the way the case was presented, we approached our deliberations using the entire evidentiary record. We went through the areas where Staff identified problems or issues with Liberty's original or rebuttal positions, and resolved those disputes based on governing law, precedent, ratemaking principles, and our collective judgment. The disputes ranged across every aspect of the case. They included revenue and expense issues like the proper time to count customers, payroll, prepayments of obligations like property taxes, and multiple aspects of the depreciation of assets; and they included determinations about the prudence of certain of Liberty's large capital investments, like the construction and use of the Concord training center and the iNATGAS facility. As explained above, the result of all of the decisions we had to make led to a conclusion that we could not approve Liberty's request or the settlement offered by Liberty and the OCA, because neither would have produced just and reasonable rates. Instead, we compiled the effects of the various decisions and calculated a revenue deficiency that will produce rates we find are just and reasonable.

This case also presented significant matters that do not affect the Company's revenue requirement. The two most significant were the proposed consolidation of the rates of the Keene Division with rates charged by the EnergyNorth Division; and the proposed decoupling of rates with monthly weather normalization.

The decision on consolidation presented a number of conflicting objectives, as argued well by the Company and Staff. On balance, we concluded that consolidation is necessary to the continued viability of the Keene Division and is consistent with the approach we approved for the Company's other recent expansions, and determined that the modest shifts of costs to the rest of Liberty's customers are not unreasonable.

Decoupling, as approved in this order, represents a significant change in how Liberty operates. Liberty, the OCA, and Staff all agreed that some measure of decoupling was appropriate for the Company at this time. Decoupling eliminates certain perverse incentives for the Company to encourage usage of gas by its customers, by adjusting rates to ensure a certain level of recovery by Liberty. Including monthly weather normalization, which was championed by the OCA and agreed to by Liberty in its settlement with the OCA, was opposed by Staff. Monthly weather normalization will further reduce risks to Liberty by reducing fluctuations in revenue caused by changes in the weather. If decoupling is implemented successfully, customers should see enhanced opportunities for cost-effective energy efficiency measures to reduce consumption and lower their energy costs.

The decision to authorize decoupling with weather normalization leads to two other decisions. First, it allows the reduction in fixed customer charges, a traditional part of any utility's rate structure. Because decoupling reduces the risk that the utility will not receive its expected revenue, it allows fixed charges to be reduced. It also makes variable charges, based on usage, a larger part of a customer's bill and thus encourages conservation and efficient use. Second, the risk reduction allows for a small reduction in the appropriate return on equity. While the settlement called for that a return on equity of 9.4 percent, a figure Staff agreed would be appropriate, the reduction in risk associated with decoupling leads us to reduce the return on equity to 9.3 percent.

We recognize that this order calls for major changes to the way Liberty interacts with its customers, and we applaud Liberty for bringing forward a number of innovative proposals. As set forth in the body of the order, we will be monitoring the situation in Keene, including the effects of the rate consolidation on the rest of Liberty's customers, and the implementation and effects of decoupling closely in the next few years. In its next rate case, which Liberty must file with a test year no later than 2020, we will require Liberty to demonstrate its efforts to increase energy efficiency in its service territories. We expect Liberty to be in close contact with Staff to ensure smooth transitions and eliminate surprises going forward.

Based upon the foregoing, it is hereby

ORDERED, that Liberty's Petition for Permanent Rates filed on April 28, 2017, is hereby denied; and it is

FURTHER ORDERED, that the Liberty Agreement Regarding Permanent Rates filed by Liberty and the OCA on February 27 and as revised on March 1, 2018, is hereby denied; and it is

FURTHER ORDERED, that Liberty be permitted to increase its base distribution rates effective with service rendered on and after May 1, 2018, by $8,060,117 on an annual basis; and it is

FURTHER ORDERED, that Liberty be permitted to increase base rates for a step adjustment currently estimated to be $4,729,953, said adjustment to be updated for actual figures but such increase to be capped at $5,044,835, effective with service rendered on and after May 1, 2018; and it is

FURTHER ORDERED, that Liberty shall decrease its base rates by an amount equal to $2,394,065 to reflect the impacts of the 2018 Tax Act, said figure to be reviewed and updated in a proceeding established pursuant to DG 18-001 and any adjustment to this number to be made through the LDAC; and it is

FURTHER ORDERED, that effective with service rendered on and after May 1, 2018, customers in Liberty's EnergyNorth and Keene divisions will pay the same distribution rates; and it is

FURTHER ORDERED, that, subject to review, adjustment, and final approval, Liberty is authorized to begin recovery of $530,000 of rate case expenses, through the LDAC effective May 1, 2018, and it is

FURTHER ORDERED, that any adjustments following review and final approval of rate case expenses shall be recovered through the LDAC; and it is

FURTHER ORDERED, that Liberty is authorized to begin recovery of the difference between the authorized annual temporary and permanent rates, through the LDAC effective May 1, 2018; and it is

FURTHER ORDERED, that Liberty shall file its next distribution rate case using a test year ending no later than December 31, 2020, and that rate case shall include a report on the effects of decoupling as detailed above; and it is

FURTHER ORDERED, that Liberty shall file illustrative tariffs and draft customer notices detailing the rates, terms, and conditions associated with decoupling within 45 days from the date of this order; and it is

FURTHER ORDERED, that Staff's Motion for Confidential Treatment filed on January 8, 2018, is hereby granted; and it is

FURTHER ORDERED, that Liberty shall file tariffs conforming with this Order within 15 days of the date of this order, in accordance with N.H. Code Admin. Rules Puc 1603.02(b).

By order of the Public Utilities Commission of New Hampshire this twenty-seventh day of April, 2018.

Martin P. Honigberg Chairman	Kathryn M. Bailey Commissioner	Michael S. Giaimo Commissioner

Attested by:

Debra A. Howland
Executive Director

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Appendices
Docket No. DG 17-048

Liberty Utilities (EnergyNorth and Keene)
List of Appendix

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Summary Comparison of Computation of Revenue Requirement and Revenue Deficiency

Line	Description	Company Proposed (A)	Commission Adjustments (B)	Total (C)
1	Rate Base	$ 252,009,027	$ (7,619,599)	$ 244,389,428
2	Rate of Return	7.36%	-0.56%	6.80%
3	Return Requirement	18,547,864	(1,929,383)	16,618,481
4	Adjusted Net Operating Income	9,735,083	1,757,176	11,492,259
5	Deficiency	8,812,781	(3,686,560)	5,126,222
6	Income Tax Effect	5,732,161	(2,397,875)	3,334,286
7	Revenue Deficiency	$ 14,544,943	$ (6,084,435)	$ 8,460,508
8	iNATGAS Adjustment (Appendix 2)		$ (400,391)	$ (400,391)
9	Revenue Deficiency with iNATGAS Adjustment		$ (6,484,826)	$ 8,060,117

Other Base Rate Adjustments Effective May 1, 2018

Line	Description	Total
10	Impact of Tax Act (Appendix 3)	$ (2,394,065)
11	Increase in Annual Revenue	$ 5,666,052
12	2018 Step Adjustment Revenue Requirement (Appendix 4)	$ 4,729,953
13	Increase in Annual Revenue	$ 10,396,005

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Revenue Requirements and Revenue Deficiency

Line	Description	Company Proposed (A)	Adjustments (B)	Total (C)
1	**Rate Base**			
2	Plant in Service	$ 477,955,645	$ (1,327,047)	$ 476,628,598
3	Accumulated Depreciation & Amortization	(156,540,351)	73,137	(156,467,214)
4	Net Plant in Service	$ 321,415,293	$ (1,253,910)	$ 320,161,384
5	Material and Supplies	$ 6,948,817	$ (3,662,176)	$ 3,286,641
6	Prepayments	2,767,078	(2,767,078)	-
7	Cash Working Capital	2,756,124	63,566	2,819,690
8	Accumulated Deferred Income Tax	(80,054,998)	-	(80,054,998)
9	Customer Deposits	(1,823,289)	-	(1,823,289)
10	Total Rate Base	$ 252,009,027	$ (7,619,598)	$ 244,389,428
11	**Rate of Return**	7.36%		6.80%
12	**Return Requirement**	$ 18,547,864	$ (1,929,383)	$ 16,618,481
13	**Revenues**			
14	Operating Revenue	$ 70,845,966	$ 929,551	$ 71,775,517
15	Other Revenues	881,259	-	881,259
16	Total Revenues	$ 71,727,225	$ 929,551	$ 72,656,776
17	**Expenses**	$ (903,867)		
18	O&M-Gas		0	$ (903,867)
19	O&M-Distribution	12,815,613	(46,752)	12,768,861
20	Customer Accounting	6,158,080	-	6,158,080
21	Sales and New Business	163,927	-	163,927
22	Administration & General	12,823,203	(288,014)	12,535,189
23	Depreciation and Amortization	19,270,782	(1,701,987)	17,568,795
24	Taxes other than Income Taxes	11,145,837	(27,545)	11,118,292
25	Income Taxes	1,843,566	1,236,672	3,080,238
26	Ratemaking Adjustment per DG 11-040	(1,325,000)	-	(1,325,000)
27	Total Operating Expenses	$ 61,992,142	$ (827,625)	$ 61,164,516
28	**Net Operating Income**	$ 9,735,083	$ 1,757,176	$ 11,492,259
29	**Income Deficiency**	$ 8,812,781	$ (3,686,560)	$ 5,126,222
30	Revenue Conversion Factor	1.65044		1.65044
31	Revenue Deficiency	$ 14,544,943	$ (6,084,435)	$ 8,460,508
32	iNATGAS Adjustment		$ (400,391)	(400,391)
33	**Revenue Deficiency with iNATGAS Adjustment**		$ (6,484,826)	$ 8,060,117

Notes and Sources
Company Proposed - Exhibit 24A (Simek & Dane Rebuttal Testimony)

Distribution Revenue	$ 71,727,225	$ 72,656,776
Revenue Deficiency	$ 14,544,943	$ 8,060,117
% Increase over Test Year Distribution Revenue	20.3%	11.1%

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Computation of Gross Up for Income Taxes

Line	Description	Company (A)	Adjustment (B)	Adjusted Amount (C)
1	NH Tax Rate	8.20%		8.20%
2	Federal Statutory Tax rate	34.00%		34.00%
3	Federal Effective Tax rate (1-State rate*Federal rate)	31.21%		31.21%
4	Total Composite Tax rate	39.41%		39.41%
5	Revenue Requirement Gross-Up Factor	60.590%		60.590%
6	Revenue Conversion Factor	1.65044		1.65044

Notes and Sources

Exhibit 53 - Bates page 21 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Rate of Return Calculation - 9.30% ROE

Line	Description	Capital Structure	Cost %	Weighted Cost %
		(A)	(B)	(C)
	Company Proposed Rate of Return			
1	Common Stock	50.00%	10.30%	5.15%
2	Long-Term Debt	50.00%	4.425%	2.21%
3	Total	100.00%		7.36%
	Commission Rate of Return			
4	Common Stock	49.21%	***9.30%***	4.58%
5	Long-Term Debt	49.85%	***4.42%***	2.20%
6	Short-Term Debt	0.95%	2.49%	0.02%
7	Total	100.00%		6.80%

Notes and Sources
Company Proposed: Exhibit 53 - Bates page 23 (Laflamme & Mullinax Supplemental Testimony)
Commission Rate of Return: Exhibit 29 - Bates page 4 (Settlement Agreement)
Commission Rate of Return uses the Settlement Agreement capital structure and cost of debt.

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Impact of Commission **Rate of Return** on Company's Revenue Deficiency

Line	Description	Company Proposed (A)	Adjustment (B)	Commission (C)
1	**Total Rate Base**	$ 252,009,027		$ 252,009,027
2	**Rate of Return**	7.36%	-0.56%	6.80%
3	**Return Requirement**	$ 18,547,864	$ (1,411,251)	$ 17,136,614
4	**Net Operating Income**	$ 9,735,083		$ 9,735,083
5	**Income Deficiency**	$ 8,812,781		$ 7,401,531
6	Revenue Conversion Factor	1.65044		1.65044
7	Revenue Deficiency	$ 14,544,943	$ (2,329,181)	$ 12,215,762

Notes and Sources

Column A: Summary Totals from Schedule 1
Line 2: Schedule 2

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Commission Ratemaking Adjustments

Line	Description	Company Proposed	Commission Adjustment 1	Commission Adjustment 2	Commission Adjustment 3	Commission Adjustment 4	Commission Adjustment 5	Commission Adjustment 6	Commission Adjustment 7	Commission Adjustment 8	Commission Adjustment 9	Commission Adjustment 10	Total Adjustments	Totals
		(A)	(B)	(C)	(D)	(E)	(F)	(H)	(E)	(G)	(I)	(K)	(J)	(M)
	Reference Schedule		Schedule 3.1	Schedule 3.2	Schedule 3.3	Schedule 3.4	Schedule 3.5	Schedule 3.6	Schedule 3.7	Schedule 3.8	Schedule 3.9	Schedule 3.10		
1	**Rate Base**													
2	Plant in Service	$ 477,955,645				$ (1,327,047)							$ (1,327,047)	$ 476,628,598
3	Accumulated Depreciation & Amortiza	(156,540,351)				73,137							73,137	(156,467,214)
4	Net Plant in Service	321,415,294	-	-	-	(1,253,910)	-	-	-	-	-	-	(1,253,910)	320,161,384
														-
5	Material and Supplies	6,948,817			(3,662,176)								(3,662,176)	3,286,641
6	Prepayments	2,767,078		(2,767,078)									(2,767,078)	-
7	Cash Working Capital	2,756,124	63,566										63,566	2,819,690
8	Accumulated Deferred Income Tax	(80,054,998)											-	(80,054,998)
9	Customer Deposits	(1,823,289)											-	(1,823,289)
10	Total Rate Base	$ 252,009,026	$ 63,566	$ (2,767,078)	$ (3,662,176)	$ (1,253,910)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,619,598)	$ 244,389,428
11	**Rate of Return**	7.36%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
12	**Return Requirement**	$ 18,547,864	$ 4,322	$ (188,161)	$ (249,028)	$ (85,266)	$ -	$ -	$ -	$ -	$ -	$ -	$ (518,133)	$ 16,618,481
13	**Revenues**													
14	Operating Revenue	$ 70,845,966							$ 929,551				$ 929,551	$ 71,775,517
15	Other Revenues	881,259				$ -							-	881,259
16	Total Revenues	$ 71,727,225	$ -	$ -	$ -	$ -	$ -	$ -	$ 929,551	$ -	$ -	$ -	$ 929,551	$ 72,656,776
17	**Operating Expenses**													
18	O&M-Gas	$ (903,867)											$ -	$ (903,867)
19	O&M-Distribution	12,815,613									(46,752)		(46,752)	12,768,861
20	Customer Accounting	6,158,080											-	6,158,080
21	Sales and New Business	163,927											-	163,927
22	Administration & General	12,823,203						(209,833)		(78,181)			(288,014)	12,535,189
23	Depreciation and Amortization	19,270,782				(44,191)	(1,657,796)						(1,701,987)	17,568,795
24	Taxes other than Income Taxes	11,145,837						(18,960)		(8,585)			(27,545)	11,118,292
25	Income Taxes	1,843,566				17,416	653,372	90,172	366,354	34,196	18,426	56,736	1,236,672	3,080,238
26	Ratemaking Adjustment per DG 11-04	(1,325,000)											-	(1,325,000)
27	Total Operating Expenses	$ 61,992,141	$ -	$ -	$ -	$ (26,775)	$ (1,004,424)	$ (138,621)	$ 366,354	$ (52,570)	$ (28,326)	$ 56,736	$ (827,625)	$ 61,164,516
														-
28	**Net Operating Income**	$ 9,735,084	$ -	$ -	$ -	$ 26,775	$ 1,004,424	$ 138,621	$ 563,197	$ 52,570	$ 28,326	$ (56,736)	$ 1,757,176	$ 11,492,260
29	**Income Deficiency**	$ 8,812,780	$ 4,322	$ (188,161)	$ (249,028)	$ (112,041)	$ (1,004,424)	$ (138,621)	$ (563,197)	$ (52,570)	$ (28,326)	$ 56,736	$ (2,275,309)	$ 5,126,221
30	Revenue Conversion Factor	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044
31	**Revenue Deficiency**	$ 14,544,943	$ 7,134	$ (310,548)	$ (411,005)	$ (184,916)	$ (1,657,739)	$ (228,785)	$ (929,521)	$ (86,763)	$ (46,750)	$ 93,639	$ (3,755,255)	$ 8,460,506
														$ 8,460,508
32	Percent of Total		0.0%	2.1%	2.8%	1.3%	11.4%	1.6%	6.4%	0.6%	0.3%	-0.6%		

Adjustment 1	Cash Working Capital
Adjustment 2	Remove Prepayments Included in Cash Working Capital
Adjustment 3	Remove Fuel Inventory from Materials & Supplies
Adjustment 4	Training Center at $2,347,000
Adjustment 5	Six Year Recovery Period of Theoretical Reserve Imbalance
Adjustment 6	Modify Payroll, Payroll Taxes, and Benefits for Vacancies
Adjustment 7	Adjust Revenue to Year-End Customer Count
Adjustment 8	Remove Severance Associated with Resignations
Adjustment 9	Remove Keene Production Cost
Adjustment 10	Interest Synchronization

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NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 1
Cash Working Capital

Line	Description	Company Proposed (A)	Adjustment (B)	Amount (C)
1	**Distribution Expenses**			
2	O&M-Gas	$ (903,867)	$ -	$ (903,867)
3	O&M-Distribution	12,815,613	(46,752)	12,768,861
4	Customer Accounting	6,158,080	-	6,158,080
5	Sales and New Business	163,927	-	163,927
6	Administration & General	12,823,203	(288,014)	12,535,189
7	Total O&M Expense for CWC Calculation	$ 31,056,956	$ (334,766)	$ 30,722,190
8	**Taxes and Interest Expense**			
9	Taxes other than Income Taxes	11,145,837	(27,545)	11,118,292
10	Income Taxes	1,843,566	-	1,843,566
11	Less Deferred Income Taxes	(6,135,425)	-	(6,135,425)
12	Income Taxes (Staff's Adjustments)	-	1,179,936	1,179,936
13	Interest Synchronization	-	56,736	56,736
14	Total Taxes and Interest Expense	$ 6,853,978	$ 1,209,127	$ 8,063,105
15	Total Distribution Expenses Taxes and Interest	$ 37,910,934	$ 874,362	$ 38,785,296
16	Lead/Lag Days Ratio	7.27%		7.27%
17	Total Cash Working Capital	$ 2,756,125	$\boxed{\$\ 63,566}$	$ 2,819,691
18	**Impact to Rate Base**	**$ 2,756,125**	**$ 63,566**	**$ 2,819,691**

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 2
Remove Prepayments Included in Cash Working Capital

Line	Description	Company Proposed (A)	Adjustment (B)	Amount (C)
1	EnergyNorth			
2	Prepaid Municipal Property Taxes	$ 2,431,418	$ (2,431,418)	
3	Prepaids	273,561	(273,561)	
4	Keene			
5	Prepaid Municipal Property Taxes	40,229	(40,229)	$ -
6	Prepaids	21,870	(21,870)	-
7	Total Prepayments	$ 2,767,078	$ (2,767,078)	$ -
8	**Impact to Rate Base**	$ 2,767,078	$ (2,767,078)	$ -

Notes and Sources

Proposed EnergyNorth: Exhibit 53 - Bates page 28 (Laflamme & Mullinax Supplemental Testimony)
Column A: Attachment DBS/DSD-2, Schedule RR-EN-5-1 (Revised 11/21/17) and Schedule RR-K

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 3
Remove Fuel Inventory from Materials & Supplies

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Plant Supplies	$ 3,170,967	$ -	$ 3,170,967
2	Gas Stored Underground	2,710,013	(2,710,013)	-
3	Fuel Stock - Propane	884,306	(884,306)	-
4	UG Storage - LNG	67,857	(67,857)	-
6	5-Quarter Average	$ 6,833,143	$ (3,662,176)	$ 3,170,967
7	**Impact to Rate Base**	$ 6,833,143	$ (3,662,176)	$ 3,170,967

Notes and Sources

Exhibit 53 - Bates page 29 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 4
Training Center at $2,347,000
(Management Approved Cost - Exhibit 56, Bates page 93)

Line	Description	Company Proposed (A)	Adjustment (B)	Total (C)
1	**Rate Base**			
2	Concord Training Center	$ 3,674,047	$ (1,327,047)	$ 2,347,000
3	Accumulated Depreciation (See Note)	(218,377)	73,137	(145,240)
4	**Impact to Rate Base**	$ 3,455,670	$ (1,253,910)	$ 2,201,760
5	**Operating Income**			
6	*Revenue*			
7	Granite State Lease Payments Concord Training Center	$ 96,764	$ -	$ 96,764
8	*Expense*			
9	Depreciation Expense	$ 124,757	$ (44,191)	$ 80,566
10	Admin and General			
11	Property and Liability Insurance	350		350
12	Utilities	20,031		20,031
13	All Other Admin and O&M	51,329		51,329
14	Total Admin and General		-	
15	Property Taxes	28,516	-	28,516
16	Total Expenses	224,982	(44,191)	180,792
17	Total Operating Income	$ (128,218)	$ 44,191	$ (84,028)
18	NH Income Tax	8.20%	0.00%	8.20%
19	Effect on NH income tax expense	$ (10,514)	$ 3,624	$ (6,890)
20	Federal Taxable	$ (117,704)		$ (77,138)
21	Federal Income Tax Rate	34%	0.00%	34%
22	Effect on Federal income tax expense	$ (40,019)	$ 13,792	$ (26,227)
23	Total Taxes	$ (50,533)	$ 17,416	$ (33,117)
24	**Impact to Operating Income**	$ (77,685)	$ 26,775	$ (50,911)

Notes and Sources
Exhibit 17 - Bates page 55 (Laflamme & Mullinax Testimony)

	Cost Basis	Depreciation	as % of cost
390 General Structures/Equipment	$ 3,585,294	$ 211,757	5.91%
Other Training Center Plant	88,753	6,619	
Training Center	3,674,047	218,377	
Approved Cost	2,347,000	138,620	(cost * 5.91%)
Other Training Center Plant	88,753	6,619	
Aug '14 Approved Cost	2,435,753	$ 145,240	
SPF Testimoy (BP 93) Aug '14 approved cost	2,347,000		
Actual Cost	3,674,047		
Adjustment - Original less Actual	$ (1,327,047)		

	Plant in Service	Depreciation Rate	Annual Depreciation
390 General Structures/Equipment	$ 3,743,921		
Fast Track Costs Removed in 11/21/17 Update	(158,627)		
Adjusted 390	$ 3,585,294	3.33%	119,390
394 Tools, Shop, Garage Equipment	39,231	5.26%	2,064
397 Communications Equipment	18,313	6.67%	1,221
398 Miscellaneous Equipment	31,209	6.67%	2,082
	$ 3,674,047		$ 124,757
Column A, Lines 10-13: Response to Staff 2-26			
Adjusted 390	2,258,247	3.33%	75,200
394 Tools, Shop, Garage Equipment	39,231	5.26%	2,064
397 Communications Equipment	18,313	6.67%	1,221
398 Miscellaneous Equipment	31,209	6.67%	2,082
	$ 2,347,000		$ 80,566
			$ (44,191)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 5
Six Year Recovery Period of Theoretical Reserve Imbalance

Line	Description	Company Proposed	Adjustment	Amount
		(A)	(B)	(C)
1	Depreciation per Books	$ 156,434,621	-	$ 156,434,621
2	Theoretical Reserve with Net Salvage	165,193,965	-	165,193,965
3	Accumulated Reserve on Accounts 392, 396, and 12·	1,187,434	-	1,187,434
4	Depreciation, Theoretical Reserve with Net Salvage	166,381,399		166,381,399
5	Difference	9,946,778		9,946,778
6	Recovery Period	3.00	3.00	6.00
7	Reserve Imbalance Annual Recovery	$ 3,315,593	$ (1,657,796)	$ 1,657,796
18	NH Income Tax	8.20%	0.00%	8.20%
19	Effect on NH income tax expense	$ (271,879)	$ 135,940	$ (135,939)
20	Federal Taxable	$ 3,043,714		$ 1,521,857
21	Federal Income Tax Rate	34%	0.00%	34%
22	Effect on Federal income tax expense	$ (1,034,863)	$ 517,432	$ (517,431)
23	Total Taxes	$ (1,306,742)	$ 653,372	$ (653,370)
24	**Impact to Operating Income**	$ (2,008,851)	$ 1,004,424	$ (1,004,426)

Notes and Sources
Column A: Exhibit 53 - Bates page 32 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 6
Modify Payroll, Payroll Taxes, and Benefits for Vacancies

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	**Payroll**			
2	Proforma Total Salary and Wages	$ 29,788,526		$ 29,788,526
3	Less Salaries for Average Vacancies			
4	Average Vacant Positions during 2017		3.50	
5	Average Salaries and Wages per Position		$ 96,092	
6	Adjusted Total Salaries and Wages	$ 29,788,526	$ (336,322)	$ 29,452,204
7	Allocation factor to EN	71.2%		71.2%
8	Salaries and Wages to EN	$ 21,203,848		$ 20,964,450
9	Allocation factor to EN OpEx	72.1%		72.1%
10	Salaries and Wages to EN OpEx	15,293,697	(172,671)	15,121,026
11	**Payroll Taxes**			
12	Proforma Total Salary and Wages	$ 29,788,526	$ (336,322)	$ 29,452,204
13	Payroll Tax Rate (%)	10.98%		10.98%
14	Adjusted Total Payroll Taxes	3,270,922		3,233,992
15	Allocation factor to EN	71.2%		71.2%
16	Payroll Taxes to EN	$ 2,328,284		$ 2,301,997
17	Allocation factor to EN OpEx	72.1%		72.1%
18	Payroll Taxes to EN OpEx	1,679,321	(18,960)	1,660,361
19	**Employer Benefits**			
20	Proforma Total Salary and Wages	$ 29,788,526	(336,322)	$ 29,452,204
21	Health Care and Other / Proforma Total Salaries and Wages	17.5%		17.5%
22	Health Care and Other	5,203,308	(58,747)	5,144,561
23	Proforma Total Salary and Wages	$ 29,788,526		$ 29,452,204
24	401(k) Matching / Proforma Total Salaries and Wages	4.00%		4.00%
25	401(k) Matching	1,191,541		1,178,088
26	Adjusted Total Health Care and 401(k) Match	$ 6,394,849		$ 6,322,649
27	Allocation factor to EN	71.4%		71.4%
28	Health Care and 401(k) Match to EN	$ 4,563,252		$ 4,511,731
29	Allocation factor to EN OpEx	72.1%		72.1%
30	Health Care and 401(k) Match to EN OpEx	3,291,474	(37,162)	3,254,312
31	Total Payroll, Payroll Taxes, and Benefits	$ 20,264,491	$ (228,793)	$ 20,035,699
32	NH Income Tax	8.20%	0%	8.20%
33	Effect on NH income tax expense	$ (1,661,688)	$ 18,761	$ (1,642,927)
34	Federal Taxable	$ 18,602,803		$ 18,392,772
35	Federal Income Tax Rate	34%	0%	34%
36	Effect on Federal income tax expense	$ (6,324,953)	$ 71,411	$ (6,253,542)
37	Total Income Taxes	$ (7,986,641)	$ 90,172	$ (7,896,469)
38	**Impact to Operating Income**	$ (12,277,850)	$ 138,621	$ (12,139,230)

Notes and Sources

Exhibit 53 - Bates page 34 (Laflamme & Mullinax Supplemental Testimony)
Column A, Line 1: Attachment DBS/DSD-2, Schedule RR-EN-3-2 (Revised 11/21/17)
Column B, Line 3 Calculation
Average Vacancies

As of 1/1/16 (Staff Tech 3-13)	3.00
As of 11/1/17 (Staff Tech 3-13)	4.00
Average vacancies	3.50

Column B, Line 4: Calculation

Total Salaries and Wages (Att DBS/DSD-2, Sch RR-EN-3-2 Rev 11/21/17)	$ 29,788,526
Number of Employees Att DBS/DSD-2, Sch RR-EN-3-2 Rev 11/21/17)	310
Average Salaries and Wages per position	$ 96,092

Column A, Lines 7 and 9: Attachment DBS/DSD-2, Schedule RR-EN-3-2 (Revised 11/21/17)
Column A, Lines 12-18: Attachment DBS-DSD-2. Schedule RR-EN-3-3 (Revised 11/21/17)
Column A, Lines 20-30: Attachment DBS-DSD-2, Schedule RR-EN-3-4 (Revised 11/21/17)

Salaries and Wages to EN OpEx	(172,671)
Health Care and 401(k) Match to EN OpEx	(37,162)
Adjustment to Carryforward to Schedule 3	(209,833)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 7
Adjust Revenue to Year-End Customer Count

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Operating Revenue	$ 83,244,364	$ 929,551	$ 84,173,915
2	NH Income Tax	8.20%	0.00%	8.20%
3	Effect on NH income tax expense	$ 6,826,038	$ 76,223	$ 6,902,261
4	Federal Taxable	$ 76,418,326		$ 77,271,654
5	Federal Income Tax Rate	34%	0%	34%
6	Effect on Federal income tax expense	$ 25,982,231	$ 290,131	$ 26,272,362
7	Total Taxes	$ 32,808,269	$ 366,354	$ 33,174,623
8	**Impact to Operating Income**	$ 50,436,095	$ 563,197	$ 50,999,292

Notes and Sources

Exhibit 53 - Bates page 39 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 8
Remove Severance Associated with Resignations

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Payroll - Severance	$ 144,130	$ (78,181)	$ 65,949
2	Payroll Tax Rate (%)	10.98%		10.98%
3	Payroll Taxes	15,826	$ (8,585)	7,242
4	Total Severance Payroll and Payroll Taxes	$ 159,956	$ (86,766)	$ 73,191
5	NH Income Tax	8.20%	0.00%	8.20%
6	Effect on NH income tax expense	$ (13,116)	$ 7,114	$ (6,002)
7	Federal Taxable	$ 146,840		$ 67,189
8	Federal Income Tax Rate	34%	0.00%	34%
9	Effect on Federal income tax expense	$ (49,926)	$ 27,082	$ (22,844)
10	Total Taxes	$ (63,042)	$ 34,196	$ (28,846)
11	**Impact to Operating Income**	$ (96,914)	$ 52,570	$ (44,345)

Notes and Sources
Exhibit 53 - Bates page 41 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 9
Remove Keene Production Cost

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Keene Production Costs	$ 46,752	$ (46,752)	$ -
2	NH Income Tax	8.20%	0.00%	8.20%
3	Effect on NH income tax expense	$ (3,834)	$ 3,834	$ -
4	Federal Taxable	$ 42,918		$ -
5	Federal Income Tax Rate	34%	0.00%	34%
6	Effect on Federal income tax expense	$ (14,592)	$ 14,592	$ -
7	Total Taxes	$ (18,426)	$ 18,426	$ -
8	**Impact to Operating Income**	$ (28,326)	$ 28,326	$ -

Notes and Sources

Staff Tech 1-1: Exhibit 53 - Bates page 74 (Laflamme & Mullinax Supplemental Testimony)
Column A: Response to Staff Tech 1-1, Schedule RR-K-3-5
Schedule RR-K-5: Exhibit 3 - Bates page 63 (Simek & Dane Testimony)

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NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 10
Interest Synchronization

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Rate Base	$ 252,009,027	(7,619,599)	244,389,428
2	Interest Component of Rate of Return	2.21%		2.22%
3	Interest Attributable to Rate Base	5,569,399		5,425,445
4	NH Income Tax	8.20%	0.0%	8.20%
5	Effect on NH income tax expense	$ (456,691)	$ 11,805	$ (444,886)
6	Federal Taxable	$ 5,112,708		$ 4,980,559
7	Federal Income Tax Rate	34%	0.0%	34%
8	Effect on Federal income tax expense	$ (1,738,321)	$ 44,931	$ (1,693,390)
9	Total Taxes	$ (2,195,012)	$ 56,736	$ (2,138,276)
10	**Impact to Operating Income**	$ 2,195,012	$ (56,736)	$ 2,138,276

Notes and Sources

Column A and C, Line 2: Schedule 2 (see below)

	(A)	(C)
Long-Term Debt	2.21%	2.20%
Short-Term Debt	-	0.02%
	2.21%	2.22%

Commission
Revenue Requirement for iNATGAS Investment
Computation of Revenue Requirement Using Projected with AFUDC & Actual Capital Investment

		Projected	Actual
Capital Investment		**Projected**	**Actual**
Year of Operation		**1**	**1**
Calendar Year		**2017**	**2017**
Investment			
Compressors		1,000,000	1,100,000
Piping, meter set, survey, etc		865,000	3,080,084
Land (pro-rated)		200,000	200,000
Contingency (Projected)		180,000	-
AFUDC (Projected - Exhibit 51)		51,307	435,510
Total Amount		2,296,307	4,815,594
Deferred Tax Calculation			
Annual Tax Depreciation (no bonus in 2014)	MACRS 15 year	104,815	230,780
Annual Book Depreciation (30-yr prop)	3.33%	69,877	160,520
Annual Book/Tax Timer		34,938	70,260
Book/Tax Timer		34,938	70,260
Effective Tax Rate		39.41%	39.41%
Deferred Tax Reserve		13,720	27,640
Rate Base Calculation			
Plant In Service		2,296,307	4,815,594
Accumulated Depreciation		(69,877)	(160,520)
Net Plant in Service		2,226,430	4,655,074
Deferred Tax Reserve		(13,720)	(27,640)
Year End Rate Base		2,212,710	4,627,434
Revenue Requirement Calculation			
Year End Rate Base		2,212,710	4,627,434
Pre-Tax ROR		9.78%	9.78%
Return and Income Taxes		216,403	452,563
Book Depreciation - annual		69,877	160,520
Property Taxes *	3.03%	67,461	141,049
Annual Revenue Requirement		353,741	754,132
Revenue at Minimum Take-or-Pay		192,600	192,600
Revenue Deficiency		161,141	561,532

Commission Proforma Adjustment for iNATGAS Revenue Requirement (Projected minus Actual) **(400,391)**

Staff Proposed Capital Structure/ROR

	Ratio	Rate	Weighted Rate	Tax Rate	Pre Tax
Long Term Debt	49.85%	4.42%	2.20%		2.20%
Short Term Debt	0.95%	2.49%	0.02%		0.02%
Common Equity	49.21%	9.30%	4.58%	39.41%	7.55%
	100.01%		6.80%		9.78%

* Property tax rate reflects actual calendar year 2016 ratio of municipal tax expense to average net plant in service

DG 17-048
Impact of Tax Act

	Description	
1	Permanent rate increase	10,300,000
2	Original gross-up	1.6504
3	Increase before gross-up (line 1 * line 2)	6,240,911
4	Gross-up with new tax rates	1.3789
5	Revised Gross-up increase (line 3 * line 4)	8,605,593
6	Difference in Gross-up (line 5 - line 1)	(1,694,407)
7	Excess DIT ($27,321,620 /39.05 years)*	(699,657)
8	Total annual amount to return to customers (line 6 + line 7)	(2,394,065)

* Revaluing the existind deferred tax assets and liabilities at the lower tax rates resulted in a net amount of excess deferred tax liaiblity of $27,321,620 which will be amortized and returned to customers over the average remaining life of the underlying assets which is 39.05 years.

Notes & Source:
Exhibit 29 - Settlement Agreement, Attachment E (Bates page 23)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities
2018 Step Adjustment
Settlement Step Increase adjusted for ROR, current tax rates, legal & degradation fees

Line	Description	Misc. Intangible Plant	LNG Plant	Mains	Station Equipment	General-Structures	Mains	Meas. & Reg. Station Equip.	Services	Meters	Structures and Improvements	Office Equipment	Vehicles	Stores Equipment	Tools	Total
	FERC Account	*303*	*320*	*367*	*369*	*375*	*376*	*378*	*380*	*381*	*390*	*391*	*392*	*394*	*394*	
1	Capital Spending - EnergyNorth	$ 2,105,141	$ 2,020,000	$14,414,334	$ 300,000	$ 1,215,000	$ 300,000	$ 325,000	$ 1,115,000	$ 1,600,000	$ 1,156,662	$ 760,384	$ 1,978,000	$ -	$ 175,000	$ 27,464,521
2	Capital Spending - Keene	$ 25,000		$ 236,000				$ 55,000	$ 50,000	$ 10,000		$ 65,000	$ 45,000	$ 4,000		$ 490,000
3	Capital Spending - Total	$ 2,130,141	$ 2,020,000	$14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
	Deferred Tax Calculation															
4	Tax Method	MACRS15	MACRS20	MACRS20	MACRS20	MACRS39	MACRS20	MACRS20	MACRS20	MACRS20	MACRS39	MACRS7	MACRS5	MACRS7	MACRS7	
5	Tax Depreciation Rate	5.00%	3.75%	3.75%	3.75%	1.28%	3.75%	3.75%	3.75%	3.75%	1.28%	14.29%	20.00%	14.29%	14.29%	
6	Bonus Depreciation @ 0.00%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Tax Basis	$ 2,130,141	$ 2,020,000	$ 14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
8	MACRS Depreciation	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	$ 1,450,946
9	Tax Depreciation - Federal	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	$ 1,450,946
10	Tax Depreciation - State	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	
11	Book Depreciation Rate	16.13%	2.86%	1.92%	2.86%	2.86%	1.92%	2.86%	3.55%	3.03%	3.33%	5.28%	20.00%	3.33%	5.26%	
12	Book Depreciation	$ 343,592	$ 57,772	$ 281,286	$ 8,580	$ 34,749	$ 5,760	$ 10,868	$ 41,358	$ 48,783	$ 38,517	$ 43,580	$ 404,600	$ 133	$ 9,205	$ 1,328,783
13	Tax over (under) Book - Federal	$ (237,085)	$ 17,978	$ 268,101	$ 2,670	$ (19,172)	$ 5,490	$ 3,382	$ 2,330	$ 11,592	$ (23,688)	$ 74,332	$ -	$ 438	$ 15,795	$ 122,163
14	Tax over (under) Book - State	(237,085)	17,978	268,101	2,670	(19,172)	5,490	3,382	2,330	11,592	(23,688)	74,332	0	438	15,795	122,163
15	Deferred Taxes - Federal @ 21.00%	(49,788)	3,775	56,301	561	(4,026)	1,153	710	489	2,434	(4,974)	15,610	0	92	3,317	25,654
16	Deferred Taxes - State @ 7.90%	(18,730)	1,420	21,180	211	(1,515)	434	267	184	916	(1,871)	5,872	0	35	1,248	9,651
17	Deferred Tax Balance @ 27.24%	$ (68,517)	$ 5,196	$ 77,481	$ 772	$ (5,541)	$ 1,587	$ 977	$ 673	$ 3,350	$ (6,846)	$ 21,482	$ -	$ 127	$ 4,565	$ 35,305
18	Rate Base Calculation															
19	Plant in Service	$ 2,130,141	$ 2,020,000	$14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
20	Accumulated Depreciation	(343,592)	(57,772)	(281,286)	(8,580)	(34,749)	(5,760)	(10,868)	(41,358)	(48,783)	(38,517)	(43,580)	(404,600)	(133)	(9,205)	(1,328,783)
21	Deferred Tax Balance	68,517	(5,196)	(77,481)	(772)	5,541	(1,587)	(977)	(673)	(3,350)	6,846	(21,482)	0	(127)	(4,565)	(35,305)
22	**Rate Base**	$ 1,855,067	$ 1,957,032	$14,291,566	$ 290,648	$ 1,185,792	$ 292,653	$ 368,155	$ 1,122,969	$ 1,557,867	$ 1,124,991	$ 760,322	$ 1,618,400	$ 3,740	$ 161,230	$ 26,590,433
23	Revenue Requirement Calculation															
24	Return on Rate Base @ 8.51%	$ 157,934	$ 166,615	$ 1,216,735	$ 24,745	$ 100,954	$ 24,915	$ 31,343	$ 95,606	$ 132,631	$ 95,778	$ 64,731	$ 137,785	$ 318	$ 13,727	$ 2,263,818
25	Depreciation Expense	343,592	57,772	281,286	8,580	34,749	5,760	10,868	41,358	48,783	38,517	43,580	404,600	133	9,205	1,328,783
26	EN Property Tax @ 2.06%		41,512	296,222	6,165	24,969	6,165	6,679			23,770					405,483
27	Keene Property Tax @ 4.17%			9,838				2,293	2,084	417						14,633
28	Keene Insurance @ 4.25%			10,032				2,338	2,125	425		2,763	1,913	170		19,767
29	EN Insurance @ 0.20%		3,983	28,421	592	2,396	592	641	2,198	3,155	2,281	1,499	3,900	0	345	50,001
30	**Annual Revenue Requirement**	$ 501,526	$ 269,882	$ 1,842,535	$ 40,081	$ 163,068	$ 37,432	$ 54,162	$ 143,372	$ 185,411	$ 160,345	$ 112,574	$ 548,198	$ 622	$ 23,277	$ 4,082,483
31	**Adjustments**															
32	**Updated Pension and OPEB Costs (Staff Tech 3-15)**															$ 419,583
33	**2017 Legal Fees (Staff Corrected - Exhibit 54)**															$ 57,506
34	**2017 Degradation Fees (Staff Correct - Exhibit 54)**															$ 9,303
35	**Cast Iron/Bare Steel - 2016 Carry Over Adjustment (Settlement Agreement - Exhibit 29, Bates page 8)**															$ 5,375
36	**Cast Iron/Bare Steel - 2017 Carry Over Adjustment (Settlement Agreement - Exhibit 29, Bates page 8)**															$ 155,703
37	**Total Adjustments**															$ 647,470
38	**Total (Adjusted) Annual Revenue Requirement**															$ 4,729,953

Source: Exhibit 29 - Bates page 18 (Settlement Agreement)

DG 17-048
Reconciliation of Temporary & Permanent Rates
Recoupment of Under Recovery

	Description		
1	Permanent rate increase	$8,060,117	
2	Temporary Rate Increase	$6,750,000	
3	Annual Recoupment (line 1 - line 2)		$1,310,117
4	Test Year Weatehr Normalized Sales		159,761,663
5	Recoupment per Therm Surcharge (line 3 / line 4)		$0.0082
6	Times Actual/Estimated July 1, 2017 thru April 30, 2018 Sales		161,741,745
7	Recoupment (line 5 * line 6)		$1,326,355

Source:
Exhibit 29 - Settlement Agreement, Attachment C (Bates page 20)

DG 17-048
Depreciation Accrual Rates

FERC ACCOUNT NUMBER	DESCRIPTION	ASL	NET SALVAGE %	WHOLE LIFE DEPREC. ACCRUAL RATES (Note 1)
303.00	CAPITALIZED SOFTWARE	6.2	0	16.13
	PRODUCTION PLANT			
305.00	STRUCTURES AND IMPROVEMENTS	35.0	0	2.86
311.00	LP GAS EQUIPMENT	35.0	0	2.86
320.00	OTHER EQUIPMENT-LNG	35.0	0	2.86
320.10	OTHER EQUIPMENT-PRODUCTION	35.0	0	2.86
	STORAGE PLANT			
361.00	STRUCTURES AND IMPROVEMENTS-LNG	35.0	0	2.86
363.50	OTHER EQUIPMENT-LNG	35.0	0	2.86
	TRANSMISSION PLANT (Note 2)			
366.20	STRUCTURES AND IMPROVEMENTS (reclass to 375)	35.0	0	2.86
366.30	STRUCTURES AND IMPROVEMENTS-OTHER (reclass to 375)	35.0	0	2.86
367.00	MAINS (reclass to 376)	60.0	-15	1.92
369.00	MEASURING AND REGULATING STATION EQUIP. (reclass to 3	35.0	0	2.86
	DISTRIBUTION PLANT			
380.00	SERVICES	45.0	-60	3.55
381.00	METERS	32.0	0	3.13
381.10	METERS-INSTRUMENT	32.0	0	3.13
381.20	METERS-ERTS	15.0	0	6.67
382.00	METER INSTALLATIONS	32.0	0	3.13
387.00	OTHER EQUIPMENT	19.0	0	5.26
	GENERAL PLANT			
390.00	STRUCTURES AND IMPROVEMENTS	35.0	0	2.86
391.00	OFFICE FURNITURE AND EQUIP.	18.0	5	5.28
391.10	OFFICE FURNITURE AND EQUIP.-COMPUTERS	10.0	0	10.00
391.20	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	5.0	0	20.00
393.00	STORES EQUIPMENT	30.0	0	3.33
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	19.0	0	5.26
394.10	TOOLS, SHOP & GARAGE EQUIPMENT-CNG STATION	19.0	0	5.26
397.00	COMMUNICATION EQUIPMENT	10.0	0	10.00
398.00	MISCELLANEOUS GENERAL EQUIPMENT	15.0	0	6.67

Note 1: The calculation of deprecation accrual rates is based on the whole-life technique as follows:
1-(net salvage percent) divided by average service life

Note 2: Incorrectly classified as transmission plant, corrected through reclass as distribution plant.

Liberty Bill Impact Analysis - Residential Heating Customer

Cost of Gas Filing Methodology
Rates Effective May 1, 2019 - Estimate Based on Commission Order

Winter Season (Jan. - Apr., Nov. - Dec.) — Summer Season (May - Oct.)
Residential Heating (R3)

Rates Effective May 1, 2018		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		51	90	117	141	130	89	618	51	25	16	14	14	22	142	760
Winter:																
Cust. Chg	$14 88	$14 88	$14.88	$14 88	$14 88	$14 88	$14 88	$89 28								
Headblock	$0.5564	$28.33	$50.08	$55 64	$55 64	$55 64	$49 25	$294 56								
Tailblock	$0.5564	$0.00	$0.00	$9 67	$22 93	$16 53	$0 00	$49 13								
HB Threshold	100															
Summer:																
Cust. Chg	$14.88								$14 88	$14 88	$14.88	$14 88	$14 88	$14.88	$89 28	$178 56
Headblock	$0.5564								$11 13	$11 13	$9 01	$7 84	$7 82	$11 13	$58 06	$352 62
Tailblock	$0 5564								$17 20	$2 99	$0 00	$0 00	$0 00	$0 93	$21 13	$70 26
HB Threshold	20															
Total Base Rate Amount		$43 21	$64 96	$80 19	$93 45	$87 05	$64 13	$432 98	$43 21	$29 00	$23 89	$22 72	$22 70	$26 94	$168 46	$601 44
COG Rate - (Winter)		$0 6445	$0.6445	$0 6445	$0 8056	$0 8056	$0 8056	$0 7382								
COG amount - Winter		$32.81	$58.01	$75.66	$113 76	$104 50	$71 32	$456 05								
COG Rate - (Summer)									$0 3133	$0.3133	$0.3133	$0.3133	$0.3133	$0 3133	$0.3133	$0.6587
COG amount - Summer									$15 95	$7 95	$5 07	$4 42	$4 40	$6 79	$44 59	$500.64
LDAC	$0 0945	$0.0945	$0.0945	$0.0945	$0 0945	$0.0945	$0 0945	$0 0945	$0 0945	$0.0945	$0 0945	$0 0945	$0.0945	$0 0945	$0.0945	$0.0945
LDAC amount		$4.81	$8.50	$11.09	$13 34	$12 25	$8.36	$58.36	$4 81	$2.40	$1 53	$1 33	$1 33	$2 05	$13.45	$71 81
Total Bill		$80.83	$131.47	$166.94	$220.55	$203.80	$143.81	$947.39	$63.97	$39.34	$30.50	$28.47	$28.43	$35.78	$226.50	$1,173.89

Winter Season (Jan. - Apr., Nov. - Dec.) — Summer Season (May - Oct.)
Residential Heating (R3)

Rate Prior to Temporary Rates		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		51	90	117	141	130	89	618	51	25	16	14	14	22	142	760
Winter:																
Cust. Chg	$22.10	$22.10	$22.10	$22 10	$22 10	$22 10	$22 10	$132.60								
Headblock	$0.3495	$17 79	$31.46	$34 95	$34 95	$34 95	$30.94	$185 04								
Tailblock	$0 2892	$0.00	$0.00	$5 03	$11 92	$8 59	$0 00	$25.54								
HB Threshold	100															
Summer:																
Cust. Chg	$22 10								$22 10	$22 10	$22 10	$22 10	$22 10	$22 10	$132 60	$265 20
Headblock	$0 3495								$6.99	$6 99	$5 66	$4 93	$4 91	$6 99	$36 47	$221 51
Tailblock	$0 2892								$8.94	$1 55	$0 00	$0 00	$0 00	$0 48	$10 98	$36 52
HB Threshold	20															
Total Base Rate Amount		$39 89	$53 56	$62 08	$68.97	$65 64	$53.04	$343.18	$38.03	$30 64	$27 76	$27 03	$27 01	$29 57	$180 05	$523 23
COG Rate - (Winter)		$0 6445	$0 6445	$0 6445	$0 8056	$0 8056	$0.8056	$0 7382								
COG amount - Winter		$32 81	$58 01	$75 66	$113.76	$104 50	$71 32	$456 05								
COG Rate - (Summer)									$0 3133	$0 3133	$0.3133	$0 3133	$0 3133	$0.3133	$0 3133	$0.6587
COG amount - Summer									$15.95	$7 95	$5.07	$4 42	$4 40	$6 79	$44 59	$500 64
LDAC	$0 0856	$0 0856	$0 0856	$0 0856	$0 0856	$0 0856	$0 0856	$0 0856	$0 0856	$0 0856	$0.0856	$0 0856	$0 0856	$0 0856	$0.0856	$0.0856
LDAC amount		$4 36	$7.70	$10.05	$12 09	$11 10	$7 58	$52.88	$4 36	$2 17	$1 39	$1 21	$1 20	$1 86	$12 18	$65.06
Total Bill		$77.07	$119.27	$147.78	$194.82	$181.24	$131.93	$852.11	$58.34	$40.77	$34.22	$32.65	$32.62	$38.22	$236.82	$1,088.94

DIFFERENCE	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill	$3.76	$12.20	$19.15	$25.73	$22.56	$11.88	$95.28	$5.63	($1.42)	($3.73)	($4.18)	($4.19)	($2.44)	($10.33)	$84.95
% Change	4.88%	10.23%	12.96%	13.21%	12.44%	9.00%	11.18%	9.65%	-3.49%	-10.89%	-12.80%	-12.84%	-6.39%	-4.36%	7.80%
Base Rate	$3.31	$11 40	$18 11	$24 48	$21 40	$11 09	$89 80	$5 18	($1 65)	($3 87)	($4 30)	($4 31)	($2 63)	($11 59)	$78.21
% Change	8.30%	21 28%	29.18%	35.49%	32 61%	20.91%	26 17%	13.61%	-5 37%	-13 94%	-15 93%	-15 96%	-8 91%	-6.44%	14 95%
COG & LDAC	$0 45	$0.80	$1 04	$1 25	$1 15	$0 79	$5 48	$0 45	$0 23	$0 14	$0 13	$0 12	$0.19	$1 26	$6.75
% Change	1.22%	1.22%	1.22%	1.00%	1.00%	1.00%	1.08%	2.23%	2.23%	2.23%	2 23%	2.23%	2 23%	2.23%	1.19%

Docket No. DG 22-___
Attachment ELM-1

Appendix 7
Page 2 of 2
DG 17-048

Liberty Bill Impact Analysis - KEENE Residential Heating Customer

Cost of Gas Filing Methodology
Rates Effective May 1, 2019 - Estimate Based on Commission Order

Winter Season (Jan. - Apr., Nov. - Dec.) / Summer Season (May - Oct.)
Keene Residential to EnergyNorth Residential Heating (R3)

Rates Effective May 1, 2018

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		40	76	104	110	117	87	534	57	29	17	17	22	17	159	693
(Average per DG 18-052 Keene Summer COG)																
Winter:																
Cust. Chg	$14 88	$14 88	$14 88	$14 88	$14 88	$14 88	$14 88	$89 28								
Headblock	$0 5564	$22 25	$42 28	$55 64	$55 64	$55 64	$48 40	$279 85								
Tailblock	$0 5564	$0 00	$0 00	$2 23	$5 56	$9 46	$0 00	$17 25								
HB Threshold	100															
Summer:																
Cust. Chg	$14 88								$14 88	$14 88	$14 88	$14 88	$14 88	$14 88	$89 28	$178 56
Headblock	$0 5564								$11 13	$11 13	$9 46	$9 46	$11.13	$9 46	$61 76	$341 61
Tailblock	$0 5564								$20 59	$5 01	$0 00	$0.00	$1 11	$0 00	$26.71	$43 95
HB Threshold	20															
Total Base Rate Amount		$37 13	$57 16	$72 74	$76 08	$79 97	$63 28	$386 38	$46 59	$31 01	$24 34	$24 34	$27 12	$24 34	$177.74	$564 12
COG Rate - (Winter)		$1 2533	$1 2533	$1 3008	$1 5666	$1 5666	$1 5666	$1 4468								
COG amount - Winter		$50 13	$95 25	$135 28	$172.33	$183 29	$136.29	$772.58								
COG Rate - (Summer)									$0 6281	$0 6281	$0 6866	$0 7766	$0 7851	$0 7851	$0 6887	$1 2729
COG amount - Summer									$35 80	$18.21	$11 67	$13 20	$17 27	$13 35	$109 51	$882 09
LDAC	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0.0945	$0 0945	$0 0945	$0 0945	$0.0945
LDAC amount		$3.78	$7 18	$9 83	$10 39	$11 05	$8 22	$50 45	$5 39	$2 74	$1 61	$1 61	$2 08	$1 61	$15.02	$65.47
Total Bill		$91.05	$159.59	$217.85	$258.80	$274.32	$207.80	$1,209.41	$87.78	$51.97	$37.62	$39.15	$46.47	$39.29	$302.27	$1,511.68

Winter Season (Jan. - Apr., Nov. - Dec.) / Summer Season (May - Oct.)
Keene Residential to EnergyNorth Residential Heating (R3)

CURRENT (Temporary Rates not Requested)

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		40	76	104	110	117	87	534	57	29	17	17	22	17	159	693
(Average per DG 18-052 Keene Summer COG)																
Winter:																
Cust. Chg	$9 00	$9 00	$9 00	$9 00	$9 00	$9 00	$9 00	$54 00								
Block 1	$1 1522	$46 09	$87 57	$92 18	$92 18	$92 18	$92 18	$502.36								
Block 2	$0.9442	$0.00	$0 00	$22 66	$28 33	$34.94	$6 61	$92 53								
Block 3	$0 7946	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00								
BL1 Threshold	80															
BL2 Threshold	120															
Summer:																
Cust. Chg	$9 00								$9 00	$9 00	$9.00	$9 00	$9 00	$9 00	$54 00	$108.00
Block 1									$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$502 36
Block 2	$0 9442								$0 00	$0.00	$0 00	$0.00	$0 00	$0 00	$0.00	$92.53
Block 3	$0 7946								$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	$0.00	$0.00
BL1 Threshold	80															
BL2 Threshold	120															
Total Base Rate Amount		$55 09	$96 57	$123 84	$129 50	$136 11	$107 79	$648.89	$9 00	$9 00	$9 00	$9.00	$9.00	$9 00	$54 00	$702 89
COG Rate - (Winter)		$1.2533	$1 2533	$1 3008	$1 5666	$1 5666	$1 5666	$1 4468								
COG amount - Winter		$50 13	$95 25	$135 28	$172 33	$183.29	$136 29	$772.58								
COG Rate - (Summer)									$0 6281	$0 6281	$0 6866	$0.7766	$0.7851	$0.7851	$0 6887	$1 2729
COG amount - Summer									$35.80	$18 21	$11 67	$13 20	$17.27	$13.35	$109.51	$882.09
LDAC	$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	$0.0000
LDAC amount		$0 00	$0 00	$0 00	$0.00	$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0 00
Total Bill		$105.22	$191.82	$259.12	$301.83	$319.40	$244.08	$1,421.47	$44.80	$27.21	$20.67	$22.20	$26.27	$22.35	$163.51	$1,584.98

DIFFERENCE:

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill		($14.17)	($32.22)	($41.27)	($43.03)	($45.08)	($36.28)	($212.06)	$42.98	$24.75	$16.94	$16.94	$20.20	$16.94	$138.76	($73.30)
% Change		-13.47%	-16.80%	-15.93%	-14.26%	-14.11%	-14.87%	-14.92%	95.93%	90.96%	81.97%	76.32%	76.88%	75.82%	84.87%	-4.62%
Base Rate		($17 95)	($39 40)	($51 10)	($53 42)	($56 14)	($44 50)	($262 51)	$37 59	$22 01	$15 34	$15.34	$18 12	$15 34	$123.74	($138.77)
% Change		-32.59%	-40 80%	-41 26%	-41 25%	-41 24%	-41 29%	-40.46%	417 70%	244 61%	170 42%	170.42%	201.33%	170 42%	229.15%	-19.74%
COG & LDAC		$3.78	$7 18	$9 83	$10 39	$11 05	$8 22	$50 45	$5 39	$2.74	$1 61	$1.61	$2 08	$1 61	$15.02	$65 47
% Change		7.54%	7.54%	7 26%	6 03%	6.03%	6 03%	6.53%	15.04%	15.04%	13.76%	12.17%	12.03%	12.03%	13.72%	7.42%

(1) Residential Heating Typical Usage: Single family detached home using gas for heat, hot water and cooking (from DG 18-052 Summer COG)

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

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Docket #: 17-048-1 Printed: April 26, 2018

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

David B. Simek
Manager, Rates & Regulatory Affairs
O: 603-216-3514
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RECEIVED
JUN 11 2018
PUBLIC UTILITIES COMMISSION

June 11, 2018

Via Hand Delivery and Electronic Mail

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

Re: DG 17-048; Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities Distribution Service Rate Case Compliance

Dear Ms. Howland:

In compliance with Commission Order No. 26,122 dated April 27, 2018, enclosed for filing please find Liberty Utilities' illustrative tariff (see Attachment A) and draft customer notice detailing the rates, terms, and conditions associated with decoupling (see Attachment B). The notice also includes educational material that provides a definition of decoupling, a description of how the mechanism will work, and the changes customers can expect to see on their monthly bills. The Company plans to work directly with Staff and the OCA to further develop this communication and educational material following their initial review of the enclosed information, as shown in the attached timeline for customer communications (see Attachment C).

Included with this filing is the LDAC section of the Company's tariff (Section 17). The Proposed Revenue Decoupling Mechanism is detailed under the LDAC section of the Company's tariff. The Revenue Decoupling Adjustment Clause (RDAC) includes detail regarding the RDAC purpose, effective date, applicability, definitions, the underlying calculations and formulas, application to customer bills, and reporting requirements.

Liberty will contact the Commission Staff and the OCA in the next few weeks to commence discussion on the enclosed material and to begin refining the informational and educational material on decoupling.

Thank you for your attention to this matter. Please do not hesitate to call if you have any questions.

Sincerely,

David B. Simek

David B. Simek

Enclosures
cc: Service List

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

A. Purpose. The purpose of the Local Distribution Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), Revenue Decoupling Adjustment Clause ("RDAC") charges , Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), rate case expenses ("RCE"), Residential Low Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time.

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	CC 17(C)	RDAC 17(D)	ES 17(E)	RCE 17(F)	RLIAP 17(G)
Residential Non-Space Heating – R-1, R-5	1	1	X	1	X
Residential Space Heating – R-3, R-4, R-6, R-7	1	1	X	1	X
Small C&I – G-41, G-51, G-44, G-55	1	1	X	1	X
Medium C&I – G-42, G-52, G-45, G-56	1	1	X	1	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	1	1	X	1	X

Notes:
N/A Not applicable
X Applicable to all
1 As ordered by the NHPUC

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the NHPUC as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to

actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

D. Revenue Decoupling Adjustment Clause

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's RDAC eliminates the link between volumetric sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

2. Effective Date: The RDAC shall take effect beginning on November 1, 2018, and replace the Lost Revenue Adjustment Mechanism (LRAM) established in Order No. 25,932 (Docket No. DE 15-137).

3. Applicability: The Revenue Decoupling Adjustment Factor shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC.

4. Definitions: The following definitions shall apply throughout the RDAC:

   a. Actual Base Revenue is the actual revenue derived from the Company's distribution rates for a given Decoupling Year for a Customer Class. The Company will use monthly distribution revenues and Actual Number of Customers to determine the Monthly Actual Base Revenue per Customer.

   b. Actual Number of Customers is the actual number of Equivalent Bills for the applicable Customer Class for the applicable month of the Decoupling Year.

   c. Billing Year is the 12-months commencing November 1 immediately following the completion of the Decoupling Year.

   d. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

e. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment billing rates. The two Customer Class Groups are as follows:

Residential Customer Class Group (CG1): defined as both Residential Non-Heating Customer Class and Residential Heating Customer Class, shall consist of all customers taking service pursuant to the Company's residential rate schedules. CG1 shall include customers taking service under rate schedules R-1, R-3, R-4, R-5, R-6 and R-7.

The Commercial and Industrial Customer Class Group (CG2): shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

f. Decoupling Year. The first Decoupling Year shall be the 10-month period from November 1, 2018 to August 31, 2019. Each subsequent Decoupling Year shall be the twelve months commencing September 1 through August 31.

g. Equivalent Bill. The number of days in the billing period of each customer's bill divided by 30.

h. Real-time weather normalization adjustment is the difference between actual distribution revenue billed to each customer in each billing cycle for each month or portion thereof during the Winter Period, and what distribution revenue for each customer's bill would have been based on normalized therm deliveries for the same period. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

i. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

j. Winter Period. The time period from November 1 of a given year through April 30 of the following year.

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Decoupling Year, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next Billing Year, effective November 1.

The Revenue Decoupling Adjustment shall be determined by calculating the monthly difference between the Benchmark Base Revenue per Customer times the actual number of Equivalent Bills for the applicable Customer Class and the Actual Base Revenue for that month. The sum of these monthly Revenue Decoupling Adjustments in the Decoupling Year shall be divided by forecasted Billing Year sales to derive the volumetric rate per therm to be applied to customers' bills in the Billing Year. The Revenue Decoupling Adjustment shall also include a reconciliation component for the previous Decoupling Year, which represents the difference between the accrued decoupling amount in the Decoupling Year compared to the actual revenues billed in the billing Year.

b. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CG=1}^{CG=2} \left[\left(BRPC_{T-1}^{CG} \, x \, ACUSTS_{T-1}^{CG} \right) - AR_{T-1}^{CG} \right) \right]$$

And:

$$RDAF = \frac{RD + DEF_{bal}}{P\!: Thru_T}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CG}$:	The Actual Number of Equivalent Bills for the applicable Customer Class for the most recently completed Decoupling Year (T-1)
AR_{T-1}^{CG}:	The Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year, (T-1), as defined in Section 4(D). For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.
$BRPC_{T-1}^{CG}$:	The Benchmark Base Revenue Per Equivalent Bill for the applicable Customer Class as determined in accordance with Section 4 (D) for the most recently completed Decoupling Year, stated on a monthly basis (T-1).
cg	Customer Class Groups as defined in Section 4(D).
DEF_{bal}	The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.
P: Thru:$_T$	Forecast Throughput Volumes inclusive of all firm tariff throughput for the Billing Year.
RD	The Revenue Decoupling adjustment to revenues, representing the sum of the monthly Revenue Decoupling Adjustments in the Decoupling Year.
$RDAF_T$:	The Revenue Decoupling Adjustment Factor for the Billing Year.

6. <u>Calculation of the RDAC Reconciliation Adjustments</u>

Account 1163-1756 shall contain the accumulated difference between annual revenues and the Revenue Decoupling Adjustment, as calculated by multiplying the RDAF times firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues annually, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

   a. The RDAF ($ per therm) shall be calculated annually for each Customer Group and shall be truncated at the nearest one one-hundredth of a cent per therm. The annual calculated Customer Group RDAF will be applied to the monthly firm tariff throughput for each customer in that particular Customer Group, effective November 1 of the given year.

   b. The real-time weather normalization adjustment is calculated as the difference between actual distribution revenue billed to each customer in each billing cycle for each month or portion thereof during the Winter Period, and what distribution revenue for each customer's bill would have been based on normalized therm deliveries for the same period. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

8. Information to be Filed with the Commission

   Information pertaining to the RDAC will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the LDAC. Such information shall include:

   a. The calculation of the applicable revenue decoupling revenue dollar adjustment for the Decoupling Year.

   b. The calculation of the revenue decoupling reconciliation dollar adjustment for the previous Decoupling Year.

   c. The calculation of the proposed decoupling rate per therm for each customer class group to be applied in the Billing Year.

   d. The calculation of the monthly Benchmark Base Revenue per Customer, to be utilized in the upcoming Decoupling Year. If distribution rates change during the Decoupling Year, the monthly Benchmark Base Revenue per Customer for the remaining months of the Decoupling Year will be revised and filed with the Commission.

E. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

   The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation (“RCE”) shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the

RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A: TPev}$$

where:

A: Tpev	Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.
RLIAP	RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.
RA_{RLIAP}	RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{X} = CC^{X} + RDAC^{X} + ES + GREF^{x} + RCE + RLIAP$$

and:

$$ES^{X} = RHS + MGP$$

where:

$LDAC^{X}$ = Annualized class specific LDAC.

CC^X = Annualized class specific CC or EE Charge.

$RDAC^X$ = Annualized class specific RDAC.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^X$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

K. Other Rules.

1. (1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

L. Amendments to Uniform System of Accounts.

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(E).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 17(G).

1163-1756 **Revenue Decoupling Adjustment Factor:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(D).

Draft Decoupling Message

Bill Insert

As part of the approval of Liberty Utilities' recent rate case, we will be implementing a change in the way we charge our customers for gas delivery service.

In April, the New Hampshire Public Utilities Commission issued a ruling on our rate case filing (DG 17-048). As part of the filing we requested revenue decoupling. Our request was granted and as a result you will see a change on your bill.

Revenue decoupling separates a utility's revenue from overall gas usage. If customers use more gas as a result of colder than normal temperatures, customers will receive a bill credit. Conversely, if customers use less gas as a result of warmer than normal temperatures, there will be an additional charge on customers' bills. This allows the company to more accurately set and meet budgets and removes the disincentive to promote energy efficiency programs. It also provides for more stability in bill amounts that would otherwise vary due to temperature extremes.

For a complete explanation of decoupling, please visit our website…

Website, etc.

What is Revenue decoupling? It's the disconnection or decoupling of a utility's revenue from customer usage. The Commission has determined a just and reasonable revenue level, based on the fixed costs to run and maintain a safe and reliable gas system. Under decoupling, this revenue will not be affected by customer usage that varies due to abnormal weather.

Why did Liberty ask for decoupling? This arrangement means the company can better budget and plan for expenses and revenues. It also means the company is not penalized when customers use less gas due to conservation and energy efficiency measures taken. Decoupling will also compensate for extreme weather events that put Liberty's revenue significantly above or below budget. The benefit to customers is less fluctuation in the distribution charges on their bills and further incentive to participate in energy efficiency programs.

Does this mean Liberty is guaranteed a profit regardless of how they manage their business? No. The company has an agreed level of revenue but not a guaranteed profit. The company still needs to control costs and make good business decisions in order to be profitable. Both of which are reviewed and regulated by the Commission.

How will decoupling work? Before decoupling, when we forecasted our budget, we predicted our revenue using several factors including historic trends based on weather. We know the typical amount of gas used in a "normal" month but sometimes a month can be colder or warmer than normal. If a month was colder than normal, the company made more money due to increased usage. If a month was warmer than normal, the company made less money due to decreased usage.

With decoupling we apply an adjustment to customers' bills in order to compensate for variations in expected weather during the customer's billing cycle. We calculate the difference between the typical (or normal) weather and the actual weather and apply a credit or a charge to customers' bills so that the revenue collected matches our forecast.

How will this affect my bill?

Each month you will see a new line item on your bill called Normal Weather Adjustment. This will show a credit or charge on your bill to compensate for a colder or warmer than normal month.

If the month is colder than normal, our customers will use more gas. This means we will collect more revenue than budgeted. The Normal Weather Adjustment would apply a credit to customers' bills to refund that over collection.

If a month is warmer than normal, customers will use less gas than expected and the company will fall short of its expected revenue. In this case the Normal Weather Adjustment will show up as a charge on customers' bills.

PLEASE NOTE that the Gas Supply Charge is based on market pricing. We purchase gas on the open energy market and pass those costs on to customers without a markup in price. Gas supply pricing can vary significantly. This is especially true when comparing summer to winter pricing. Decoupling will not affect the Gas Supply Charge on customers' bills.

Is my bill still based on how much gas I use? Yes, you are still charged based on the number of therms of gas you use.

Will my bill go up if I use less gas? No. Using less means you will be charged less for distribution charge, less for distribution adjustment and less for Gas Supply. Even in months where there is a normal weather adjustment charge, you will still see a reduction in your bill for using less energy.

What is the main purpose of decoupling?

The main purpose of decoupling is to promote energy efficiency. Customers who take advantage of energy efficiency measures will reduce their usage, lower bills and help the environment.

Separating a utility's revenue from overall customer usage means that the utility will have more incentive to promote energy efficiency programs, rather than selling more gas, because the utility will not incur a revenue loss as a result of energy efficiency measures utilized by customers.

Is decoupling a new concept?

Liberty Utilities is the first utility company in New Hampshire to make it part of their rate structure. While decoupling is a new concept in New Hampshire, the concept has been around for many years and is being used in over half the states in the country.

Decoupling Communications Timeline

When	Deadline	Communications Channel	Messaging	Completed Y/N
September		**CSR Talking Points**	**Explanation of Decoupling**	
	3-Sep	Develop Content		
	12-Sep	Approvals from Regulatory		
	14-Sep	Final Layout to Customer Service		
October		**Bill Insert**	**Decoupling is coming, direct to website for more info**	
	13-Jul	Develop Content		
	27-Jul	Approvals from Regulatory		
	17-Aug	Create Layout		
	17-Aug	Send to PUC for input		
	31-Aug	Proof and Approvals		
	3-Sep	Send File to Printer		
	14-Sep	Approve Print Proof		
	21-Sep	In Hand at Fiserv (Bill Print Provider)		
	24-Sep	Email to Employees and Regulators with PDF Copy		
	28-Sep	Approve Bill Print		
	1-Oct	Inserts start going out will bill cycles		
October 1st		**Web Page**	**·Overview of decoupling** **·Benefits to the customer and the company** **· Comparison of traditional and Decoupled Bills** **·Video - Decoupling overview**	
	30-Jul	Develop Content		
	10-Aug	Approvals from Regulatory		
	24-Aug	Create Page Layout in Test Environment		
	7-Sep	Make final changes in Test Environment		
	14-Sep	Make final changes		
	24-Sep	Move page to Production - Page goes live		
	24-Sep	Test in live and final changes		
	24-Sep	Send to PUC for input		
	25-Sep	Email to Employees with link to page		
October 1st		**Animated Video**	**High level explanation of Decoupling**	
	2-Jul	Develop Storyboard - Based on PG&E Video		
	9-Jul	Approvals from Regulatory		
	23-Jul	Develop Draft Video		
	30-Jul	Review with Regulatory		
	6-Aug	Make Final Changes		
	10-Aug	Final Review and Proof		
	17-Aug	Export Final File, Post to YouTube, Test		
	17-Aug	Send to PUC for input		
	20-Aug	Email with link to Employees		
October 1st		**Social Media**	**Decoupling is coming, direct to website for more info**	
	14-Sep	Develop posts for FB and Twitter		
	26-Sep	Schedule publish date		
October 15th		**Social Media**	**Video - Decoupling overview**	
	17-Aug	Develop posts for FB and Twitter		
	24-Aug	Schedule publish date		
November		**Customer Newsletter (bill Insert)**	**Article: Overview of Decoupling, direct to website for more info**	
	17-Aug	Develop Content		
	31-Aug	Approvals from Regulatory		
	14-Sep	Create Layout		
	24-Sep	Proof and Approvals		
	5-Oct	Send File to Printer		
	15-Sep	Approve Print Proof		
	15-Sep	Send to PUC for input		
	25-Oct	Email to Employees with PDF copy		
	25-Oct	In Hand at Fiserv (Bill Print Provider)		
	30-Oct	Approve Bill Print		
	1-Nov	Inserts start going out will bill cycles		

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

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

Distribution Service Rate Case

<u>Response to September 24 Secretarial Letter</u>

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company"), through counsel, respectfully responds to the September 24, 2018, Secretarial Letter (the "Secretarial Letter"), answering the three questions posed by the Commission.

In support of this motion, the Company states as follows:

1. Order No. 26,122 (Apr. 27, 2018) (the "Order") resolved the merits of this rate case and approved the "settlement decoupling proposal." *Id.* at 45 ("we approve the settlement decoupling proposal in concept"); *see* Hearing Exhibit 29 (the Liberty-OCA *Agreement Regarding Permanent Rates*); Day 5 Transcripts of March 23, 2018, Morning Session, and March 23, 2018, Afternoon Session, containing the testimony of Dr. Johnson and Mr. Therrien.

2. Because of its relevance to the Secretarial Letter, below is the text of the decoupling proposal contained in the Liberty-OCA *Agreement Regarding Permanent Rates* as it relates to the tariff and customer bills:

> The Settling Parties agree that the Company should implement a "full" decoupling mechanism that contains the following elements: (1) real-time weather normalization, calculated at the individual customer level; (2) revenue per customer design, with accrual calculations at the rate class level and billing rates aggregated into two rates – Residential and C&I; (3) Managed Expansion Program customers are subject to decoupling, but the expansion surcharge dollars (i.e., the 30% distribution premium) are

> excluded from the decoupling calculation; and (4) special contract customers are not subject to decoupling and will be excluded entirely from the decoupling calculation.
>
> The real-time weather normalization adjustment is calculated as the difference between actual distribution revenue billed to each customer in each billing cycle for each month, and what distribution revenue for each customer's bill would have been based on normalized therm deliveries. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").
>
> The annual revenue per customer adjustment will be determined by calculating the difference between actual annual distribution revenue per customer and approved annual distribution revenue per customer for two groups of customers: (a) the residential classes and (b) the commercial and industrial classes. Approved annual distribution revenue per customer for each of these two groups will be based on the approved distribution revenues and test year average customer counts for each group. The difference in total distribution revenues is calculated using this revenue per customer variance multiplied times the actual average annual customer count. This amount will be recovered from or refunded to each group over the subsequent 12-month period through a uniform charge per therm for each group.
>
> * * *
>
> The Settling Parties agree that the decoupling mechanism shall take effect beginning on November 1, 2018. On that date, decoupling will replace the Lost Revenue Adjustment Mechanism established in Order No. 25,932 (Docket No. DE 15-137), and the Company will cease any and all recovery of lost revenues attributable to energy efficiency programs outside of the decoupling mechanism.

Hearing Exhibit 29, at 10-12.

3. In summary, the "settlement decoupling proposal" that the Commission approved is "a full decoupling mechanism, that is based on revenue per customer, and includes a real-time component for weather." Day 5 Transcript, morning session, at 28 (Therrien).

4. The Commission did not order changes to the Liberty-OCA decoupling proposal that are relevant here, but directed the Company to file illustrative tariffs and customer notification materials well in advance of the mechanism's November 1 implementation date to allow time for discussion with Staff and the OCA to fine tune the details:

> Because decoupling is slated for November 1, Liberty is directed to file within 45 days of this order illustrative tariffs demonstrating the rates, terms, and conditions required to implement decoupling in conformance with existing law. Due to the novelty of the decoupling process in New Hampshire, Liberty must also submit at the same time customer notice and educational materials for review and approval by the Commission.

Order at 46; *see* eleventh ordering clause, Order at 56 ("Liberty shall file illustrative tariffs and draft customer notices detailing the rates, terms, and conditions associated with decoupling within 45 days from the date of this order").

5. Liberty filed the illustrative tariffs and draft customer notices on June 11, 2018, along with a timeline of key dates related to the development, review, and issuance of customer informational materials.

6. Liberty contacted Staff a week later to arrange a meeting to discuss the compliance filing and obtain Staff's comments. After the first agreed meeting date had to be cancelled, Staff did not provide Liberty with additional dates on which it could meet. Over the succeeding months, Liberty asked Staff for status updates on Staff's review of the compliance filing, but received no substantive responses.

7. In order to meet the mandated November 1 implementation date for decoupling, Liberty did the following during the months of June through August:

   a. Liberty directed its billing vendor make the necessary changes to its software to implement the approved decoupling mechanism. As discussed during hearing, these software changes were substantial and required significant lead time to develop and test. *See, e.g.*, Day 5, morning session, at 35-40, 105-111; Day 5, afternoon session, at 4-16, 26-28, 49-54, 101-103. The computer changes have been completed and are now being tested.

   b. Liberty also directed its billing vendor make the necessary changes to the bill presentation so that it would include the "Normal Weather Adj" line that appears on the sample bill introduced as hearing Exhibit 61, a programming task that also required lead time to implement and test prior to November 1. No party objected to the appearance of Exhibit 61 during hearing, the Order did not comment on its appearance, and Staff made no suggested changes. That software change has also been completed and is being tested.

c. Liberty continued to work on, revise, and eventually finalize the customer notice that the Company will send to customers with October bills. The mailing had to be finalized in late August to allow for printing and shipping to the bill mailing vendor in September to be ready for inclusion in October bills.

d. Finally, the Company revised the decoupling Q&A that would be put on its website, prepared a separate web page for decoupling, and created a short video to be posted on the website and distributed through social media, all to be ready by October 1.

8. On September 11, 2018, three months after the Company's June 11 compliance filing and only three weeks before the start of formal customer notification, Staff informed Liberty for the first time that it had questions about the compliance filing, including the issues raised in the Secretarial Letter. Following are Staff's questions, which were included in an email setting the agenda for a previously scheduled meeting on another topic (the numbered paragraphs correspond to the issues also raised in the Secretarial letter):

> Staff has a number of topics it would like to address at our meeting on Friday 9/14, so I provide this email as an "agenda" of sorts.
>
> * * *
>
> **Draft Decoupling Tariff filed 6/11/18**
>
> [1] Regarding the Order at 46, which requires that the decoupling tariff be "in conformance with existing law". There are questions about how this tariff squares with the provisions of RSA 378:3 and Appeal of Pennichuck Water Works, 120 NH 562 – both of which, arguably, prohibit rate adjustments made after the service is provided, as is the case with the real-time weather adjustment.
>
> Staff believes that the decoupling tariff must show the calculation of the real-time weather normalization – so that customers can follow the calculation behind the new line item adjustment on their bill. What weather data will be used? How will the weather data and the corresponding effect on usage be calculated? For example, how will base load be isolated on a monthly basis so that only heat sensitive load will be adjusted.

> [2] Staff wishes to explore ways to make the formula at Section D.5.b on p. 4 easier to follow (especially by customers).
>
> [3] Staff wants to explore why the real-time weather normalization is only set up for winter months, when we recall that during the case it was presented as a year round event.
>
> Concerning Section D.8 – Staff believes the Commission should be provided with monthly (or perhaps daily) information as to how the real-time weather adjustment was derived for each billing cycle.
>
> Staff has comments on the customer write up, which we will try to finalize for the meeting.[1]

9. Staff, Liberty, and the OCA met on Friday, September 14, at which Liberty conveyed the information discussed in this Response, and more, and also agreed to modify the tariff language. Staff provided "high level" comments on the customer notification issues on September 17. Liberty responded to those comments on September 24, provided updated customer notifications, a link to the decoupling video, and answered other questions that Staff raised. The Secretarial Letter was also issued September 24.

Question 1 – Twelve Month versus Six Month WNA

10. The Secretarial Letter states that "*Liberty proposed* a real-time weather normalization adjustment that would be made year round. According to … the illustrative tariff, however, the adjustment will only be performed during the six winter months." (Emphasis added.) The Secretarial Letter directed Liberty to "provide the reasoning behind *its decision* to now propose an illustrative tariff that limits the adjustment to the six winter

[1] The Company did not receive these comments until September 17, they were described as "high level" suggestions, and they referenced the materials filed on June 11. The Company had independently made changes during its internal review that unknowingly anticipated Staff's comments.

months [and] to explain in detail any benefits and drawbacks to its customers from the change to a winter-only adjustment." (Emphasis added.)

11. First, the Commission did not approve Liberty's weather normalization adjustment ("WNA") mechanism. The Order approved the different proposal contained in the Liberty-OCA settlement, quoted above. Liberty's initial proposal did contain a WNA mechanism with separate summer and winter periods, *see* Exhibit 8, Direct Testimony of Gregg Therrien, at Bates 318, but the WNA mechanism in the Liberty-OCA settlement, which is the proposal that the Commission approved, did not propose for it to apply 12 months per year. The approved WNA mechanism is silent as to whether it would apply for six or 12 months.[2] The Company found nothing helpful in the hearing transcript.

12. Second, implementing a year round WNA mechanism would produce unintended and unacceptable results. A fundamental step in the WNA is to compute the percentage difference between the actual and normal heating degree days (HDDs) during the applicable billing period.[3] Because HDDs are much lower in the summer and shoulder months, the percentage difference between actual and normal can be large and variable while the absolute difference in the HDDs is small. Such large relative differences and variability may give rise to inappropriately large weather adjustments for certain highly weather sensitive customers for small actual differences in HDDs.

13. For example (and these are the actual numbers behind the sample bill discussed at hearing, Exhibit 61, a corrected copy of which is attached to this Response), if the normal

[2] The reference to "annual" in the third paragraph of the settlement proposal applies to the annual revenue-per-customer adjustment, not to the time over which the decoupling mechanism will be in effect.

[3] The WNA mechanism uses this percentage to reconcile the actual therms used for heat to the therms that would have been used for heat under normal weather.

HDDs for a billing period are 897 therms, but the actual HDDs for that period were 887 therms (warmer than normal), the 10 therm difference represents a variance from normal of only 1.1%. Since the WNA mechanism is largely driven by this percentage change in actual-to-normal HDDs, the upward adjustment in Exhibit 61 was only $0.50 (out of a total variable distribution charge of $80.93). Also attached is an example of bill that resulted in a $3.73 WNA credit, covering a period colder than normal. As with Exhibit 61, this sample is based on an actual bill.

14. There are fewer HDDs in the shoulder and summer months, so a relatively small change in actual weather can give rise to a large percentage change between actual and normal HDDs. For example (and this is actual data discussed with Staff and the OCA on September 27), during the billing period of May 24 through June 22, 2018, the actual HDDs were 43 and the normal HDDs were 78, resulting in an 81% difference. A percentage difference of this magnitude is not uncommon during the shoulder and summer months. And since this percentage change is an important driver in the WNA mechanism, its application would lead to a relatively large percentage adjustment to the variable distribution portion of a relatively small bill. Such a potentially large adjustment would not be appropriate and may send conflicting and confusing price signals. Such an adjustment does not accurately reflect changes in a customer's weather-related consumption, which is small or non-existent during the non-heating season.

15. Third, the Company's billing system currently performs a "base usage" calculation for all customers, which is each customer's average use during two consecutive June, July, and August periods. Base usage is assumed to be the customer's non-heating load, which is important information that the Company uses for various billing purposes, including for

the WNA mechanism. In order to capture the base usage, the Company must disable certain functions of the billing software that are otherwise necessary for the WNA mechanism. That is, the Company cannot calculate the base usage and the WNA mechanism at the same time, so it is impossible to implement the WNA mechanism over the three summer months.

16. Paragraphs 11 through 15 above constitute the "reasoning behind [the] decision to now propose an illustrative tariff that limits the [WNA] adjustment to the six winter months."

17. The Secretarial Letter also asked the Company "to explain in detail any benefits and drawbacks to its customers from the change to a winter-only adjustment."

18. The primary customer benefit is avoiding the inappropriate and confusing adjustments that the WNA mechanism would compute if implemented over the shoulder and summer months, as described above.

19. The Company does not see customer drawbacks to a winter-only WNA mechanism. To the extent customers will not have access to the mechanism's effect of smoothing the variation in distribution charges, that effect will be small during the summer (assuming away the anomalies discussed above) given the low usage during that period.

<u>Question 2 – Specific Tariff Language</u>

20. The Secretarial Letter states that the proposed tariff language, specifically Section 17.D.7.b, "falls short" of the transparency the Commission would like to see. The Company discussed this issue with Staff and the OCA during the September 14 meeting and again during a meeting on September 27. The Company agreed to revise the tariff language and is filing that revised language under separate cover. The revisions include specific formulae

for the revenue decoupling and for the WNA mechanism, with appropriate definitions and descriptions.

<u>Question 3 – "Compliance with Existing Law"</u>

21. The third question posed by the Secretarial Letter quotes the Order's statement that the decoupling tariff must be "in compliance with existing law" and states that Liberty's compliance filing "does not address this requirement." The Commission thus directed Liberty "to file a legal memorandum explaining how the real-time weather normalization portion of the tariff as filed is 'in compliance with exiting law,'" citing RSA 378:3 and *Appeal of Pennichuck Water Works,* 120 N.H. 562 (1980). This Response is Liberty's legal memorandum.

22. It is Liberty's position that the WNA mechanism as set forth in the tariff is "in compliance with existing law" for the following reasons.

<u>RSA 378:3</u>

23. First, the opening phrase of RSA 378:3 shields the WNA mechanism from any other alleged deficiencies that may exist under that statute. RSA 378:3 states, in full:

> 378:3 Change. Unless the commission otherwise orders, no change shall be made in any rate, fare, charge or price, which shall have been filed or published by a public utility in compliance with the requirements hereof, except after 30 days' notice to the commission and such notice to the public as the commission shall direct.

Regardless of how one interprets the required "notice" and the meaning of "any rate, fare, charge or price," discussed below, the opening phrase "unless the commission otherwise orders" must also be given full effect. *State Employees Ass'n of New Hampshire, SEIU,* *Local 1984(SEA) v. New Hampshire Div. of Personnel*, 158 N.H. 338, 345 (2009) ("We also note the 'elementary principle of statutory construction that all of the words of a statute must be given effect and that the legislature is presumed not to have used superfluous or redundant words'") (citation omitted). So, if the Commission were to approve a "change" in a "rate" without "30 days' notice to the commission," a change that would otherwise violate RSA 378:3, that change would nonetheless be "in compliance with existing law" because the "commission otherwise order[ed]" that change.

24. Here, the Commission knew that the WNA mechanism would adjust the customer's bill based on variation in HDDs during the immediately preceding billing period. That is, the Commission specifically understood that the WNA mechanism has a backward-looking function, a comparison of actual to normal HDDs, before it calculates the final bill.

> The real-time weather normalization adjustment is calculated as the difference between actual distribution revenue billed to each customer in each billing cycle for each month, and what distribution revenue for each customer's bill would have been based on normalized therm deliveries

Liberty-OCA Settlement, Hearing Exhibit 29, at 11.

> The settlement also includes important non-revenue provisions, including … a decoupling plan under which revenue per customer targets would be established for each rate class. Each month, and again at the end of each year, rates would be adjusted up or down to allow the Company to collect the established revenue per customer targets. The monthly adjustments would account for changes in weather. In months when temperatures were colder than normal, customers would receive a credit on their bill to return the increased revenues that Liberty would have collected due to higher usage during the colder than normal temperatures. During warmer months, customers would pay a charge to make up for the reduced revenues attributable to the warmer temperatures.

Order at 6-7.

25. With this knowledge that the WNA mechanism would apply a credit or charge based on the prior month's weather, and with presumed knowledge of RSA 378:3's notice

requirement, the Commission approved and ordered implementation of the WNA mechanism. Thus, the WNA mechanism is "in compliance with existing law" because the Commission "otherwise order[ed]" its implementation.

26. Second, even if the Commission disregarded the "otherwise orders" language, RSA 378:3 does not render WNA mechanism illegal because the mechanism does not change "any rate, fare, charge or price." As described above, the WNA reconciles the therms actually used to the therms that would have been used under normal weather. The WNA mechanism calculates a percentage difference between actual and normal usage and multiplies that by the approved rates, giving rise to dollar adjustment. There is no change in rates and all rate components on a customer's bill will be calculated at Commission-approved rates.

27. The WNA mechanism is simply a reconciling mechanism intended to true up the effects of weather: "Rate cases are premised on normal weather, and known and measurable adjustments are made in order to normalize the rate year. That does not change with decoupling. Decoupling is a reconciling mechanism after those base rates are established." Day 5, morning session, at 32 (Therrien).

28. Third, even if the "otherwise orders" language is ignored, and even if the WNA adjustment is a "change" in a "rate, fare, charge or price," the WNA mechanism still complies with RSA 378:3 because the revised tariff language, attached, provides "30 days' notice to the commission" of that change. The tariff language describes the formulae that will be used to calculate the WNA, which is similar to the notice currently given for other billing components and arrangements such as calculating the "therm factor" and budget billing.

<u>Appeal of Pennichuck</u>

29. The Secretarial Letter directed Liberty "to explain how the tariff complies … with the NH Supreme Court's ruling in *Appeal of Pennichuck Water Works*." *Pennichuck* stands for the well-known proposition that "the earliest date on which the PUC can order temporary rates to take effect is the date on which the utility files its underlying request for a change in its permanent rates." 120 N.H. at 567. More specifically, the Secretarial Letter cited *Pennichuck* as authority for the "customers right to rely on the rates in effect at the time they consume utility service," echoing the more specific statement in *Pennichuck*: "In no event may temporary rates be made effective as to *services rendered* before the date on which the permanent rate request is filed." *Id.* (emphasis in original).

30. Liberty does not dispute these established principles, but contends that they do not apply to the WNA mechanism for reasons similar to the discussion of RSA 378:3 above. First, the WNA mechanism does not change approved "rates." The use of the term "rates" in the temporary and permanent rate statutes, RSA 378:27 through 378:29, which were the statutes at issue in *Pennichuck*, is without ambiguity. The WNA mechanism only applies approved rates.

31. And second, *Pennichuck* held that a utility could not recover rate increases for services prior to the filing of the rate case, i.e., prior to notice of the proposed rate change. Even if the WNA mechanism was considered to change rates, customers *do* have notice of

those changes through the tariff language that describes how the WNA mechanism will operate.

32. Thus, the WNA mechanism does not run afoul of the holding in *Pennichuck*.

Conclusion

33. Liberty is concerned over the process that led to the Secretarial Letter and the need for this Response. The first two questions should have been vetted during the typical process of post-order tariff review among Staff, Liberty, and the OCA, with the result being either a Staff recommendation for approval or a more developed and focused disagreement to be resolved by the Commission. Despite the Company's efforts, that process did not occur. Rather, the issues Staff raised at the last moment became the subject of a Secretarial Letter – in effect a Commission order – without the opportunity for any input from the Company. This denial of an opportunity to be heard raises due process concerns. Indeed, in the case of Question 2, the Secretarial Letter was issued before Liberty could even produce the tariff changes it agreed to make.

34. The third question, a purely legal issue, should have been raised during hearing, not five months after the Order was issued and four months after it became final. Nothing prevented the issue from being raised earlier. The Commission did not invoke RSA 365:28 to reopen the hearing, which of course requires notice and hearing, and the issue is not akin to a jurisdictional issue that a court may raise at any time. The Commission has authority

and precedent to approve mechanisms that adjust bills without violating the principles of *Pennichuck*. Again, the "therm factor" adjustment is an example.[4]

35. The Company has responded to all questions in the Secretarial Letter and to all questions and issues otherwise raised by Staff. Liberty respectfully asks the Commission to approve the tariff provisions and compliance filing.

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

By its Attorney,

Date: October 1, 2018 By: ______________________________
Michael J. Sheehan, Senior Counsel #6590
116 North Main Street
Concord, NH 03301
Telephone (603) 724-2135
michael.sheehan@libertyutilities.com

Certificate of Service

I hereby certify that on October 1, 2018, a copy of this response has been electronically forwarded to the service list.

By: ______________________________
Michael J. Sheehan

[4] The therm factor is a long accepted adjustment that converts the customer's "usage" into "therms" by a calculation that can only be done after the billing period when the Company knows the exact BTUs of the gas delivered during that month. The adjusted therms are multiplied by the approved rates, which is similar to the WNA adjustment discussed here. The therm factor adjustment has occurred without Commission concern for years.

EXHIBIT
#61
DG 17-048

Liberty Utilities

Liberty Utilities
P.O. Box 1380
Londonderry, NH 03053-1380
Visit our website at www.libertyutilities.com

FOR QUESTIONS REGARDING YOUR BILL CALL (800) 833-4200
FOR EMERGENCIES CALL (855) 327-7758

Statement

ACCOUNT INFORMATION	
Account number:	00000000-00000000
Statement #:	0000000X
Bill Date:	4/21/2015
Due date:	5/19/2015
Next meter read	
Service address:	

Meter #	Rate Code	Read Type	Days	Service dates	(Current	- Prev.)	x Multiplier	= Usage	Therm Factor	Therms
00NH000000	40-GR3	Actual	33	3/13/2015-4/16/2015	146	56	1.00000	90.00	1.03060	93

IF YOU SMELL GAS, LEAVE THE PREMISES and CALL US IMMEDIATELY: Our emergency toll-free number is 1-855-327-7758 or call 911.

ACCOUNT ACTIVITY	
Previous Balance:	0.00
Payments Received:	0.00
Balance Forward:	0.00
Current Charges:	
Minimum chg $0.6617 per day for 29 days	19.19
Distribution Chg 96.6670 units x 0.31400	30.35
Distribution Chg 139.3330 units x 0.25940	36.14
Normal Weather Adj $65.50 x -1.000%	0.66 CR
Distribution Adj 236.0000 units x 0.07720	18.22
Gas Supply Chg 236.0000 units x 0.79011	186.47
Miscellaneous Charges/Credits:	
Total Amount Due:	289.71

Total Distribution Chg = SUM(Distribtn Chg)

Normal Weather Adjustment (WNA)

Weather Normalization Factor (WNF)

SPECIAL MESSAGE

Please consider making a tax deductible donation to the Neighbor Helping Neighbor Fund by visiting nhnfund.org.

KEEP THIS PORTION FOR YOUR RECORDS

Please include your account number on your check.
Make checks payable to Liberty Utilities

DETACH AND RETURN THIS REMITTANCE PORTION OF THE BILL WITH YOUR PAYMENT

BALANCE FORWARD	CURRENT CHARGES	AMOUNT DUE	ENCLOSED AMOUNT
0.00	289.71	289.71	

Check Number:

Payment Coupon

Please check box and see reverse for: ☐ Update phone/address

Service Address:

0
0
0

LATE PAYMENT FEE:
Payments received after the due date are subject to 1.5% per month late fee.

Liberty Utilities- NH
75 Remittance Dr, Ste 1032
Chicago, IL 60675-1032

00000000-00000000

Statement #: 0000000X
Bill Date: 4/21/2015
Due Date: 5/19/2015

Statement

Liberty Utilities
P.O. Box 1380
Londonderry, NH 03053-1380
Visit our website at www.libertyutilities.com

FOR QUESTIONS REGARDING YOUR BILL CALL (800) 833-4200
FOR EMERGENCIES CALL (855) 327-7758

ACCOUNT INFORMATION	
Account number:	44507426-44111982
Statement #:	
Bill Date:	4/6/2018
Due date:	
Next meter read	
Service address:	

Meter #	Rate Code	Read Type	Days	Service dates	(Current	- Prev.)	x Multiplier	= Usage	Therm Factor	Therms
0006133194	40-GR3	Actual	30	03/08/2018-04/06/2018	2353	2210	1.00000	143.00	1.03230	148

IF YOU SMELL GAS, LEAVE THE PREMISES and CALL US IMMEDIATELY: Our emergency toll-free number is 1-855-327-7758 or call 911.

ACCOUNT ACTIVITY	
Previous Balance:	0.00
Payments Received:	0.00
Balance Forward:	0.00
Current Charges:	
Minimum chg $0.8143 per day for 30 days	24.43
Distribution Chg 100.0000 units x 0.38630	38.63
Distribution Chg 48.0000 units x 0.31970	15.35
Normal Weather Adj $53.98 x -6.9100%	3.73 CR
Distribution Adj 148.0000 units x 0.08560	12.67
Gas Supply Chg 148.0000 units x 0.80560	119.23
Miscellaneous Charges/Credits:	
Total Amount Due:	206.58

SPECIAL MESSAGE

Please consider making a tax deductible donation to the Neighbor Helping Neighbor Fund by visiting nhnfund.org.

KEEP THIS PORTION FOR YOUR RECORDS

Please include your account number on your check.
Make checks payable to Liberty Utilities

Payment Coupon

Please check box and see reverse for: ☐ Update phone/address

Service Address:

LATE PAYMENT FEE:
Payments received after the due date are subject to 1.5% per month late fee.

DETACH AND RETURN THIS REMITTANCE PORTION OF THE BILL WITH YOUR PAYMENT

BALANCE FORWARD	CURRENT CHARGES	AMOUNT DUE	ENCLOSED AMOUNT
0.00	206.58	206.58	

Check Number:

Liberty Utilities- NH
75 Remittance Dr, Ste 1032
Chicago, IL 60675-1032

44507426-44111982
Statement #:
Bill Date: 4/6/2018
Due Date:

Page	**Revision**
25	Original
26	Original
27	Original
28	Original
29	Original
30	Original
31	Original
32	First Revised
33	First Revised
34	First Revised
35	First Revised
36	First Revised
37	First Revised
38	First Revised
39	First Revised
40	First Revised
41	First Revised
41A	Original
41B	Original
42	Original
43	Original
44	First Revised
45	Original
46	First Revised
47	Original
48	First Revised
49	Original
50	First Revised
51	Original
52	First Revised
53	Original
54	First revised
55	Original

The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE AND NORMAL WEATHER ADJUSTMENT

A. Purpose. The purpose of the Local Distribution Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), Revenue Decoupling Adjustment Clause ("RDAC"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), rate case expenses ("RCE"), Residential Low

Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time. The purpose of the Normal Weather Adjustment ("NWA") is to establish procedures that allow the Company, subject to the jurisdiction of NHPUC, to calculate and apply, for each customer on a monthly basis, the Weather Normalization Factor ("WNF").

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	CC 17(C)	RDAC 17(D)	ES 17(E)	RCE 17(F)	RLIAP 17(G)
Residential Non-Space Heating – R-1, R-5	1	1	X	1	X
Residential Space Heating – R-3, R-4, R-6, R-7	1	1	X	1	X
Small C&I – G-41, G-51, G-44, G-55	1	1	X	1	X
Medium C&I – G-42, G-52, G-45, G-56	1	1	X	1	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	1	1	X	1	X

Notes:
N/A Not applicable
X Applicable to all
1 Applicable to Non-Managed Expansion Program Customers

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

D Revenue Decoupling Adjustment Clause.

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its rates for firm gas sales and firm transportation in order to reconcile Actual Base Revenue per Customer with Benchmarked Base Revenue per Customer. The Company's RDAC eliminates the link between volumetric sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.. The purpose of the NWA is to adjust each customer's bill for the difference in delivery charges caused by the variation in actual HDDs from normal HDDs during the Winter Period.

2. Effective Date: The RDAC and NWA shall take effect beginning on November 1, 2018, and replace the Lost Revenue Adjustment Mechanism (LRAM) established in Order No. 25,932 (Docket No. DE 15-137).

3. Applicability: The Revenue Decoupling Adjustment Factor and NWA shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC and NWA.

4. Definitions: The following definitions shall apply throughout the RDAC and NWA:

   a. Actual Base Revenue is the actual revenue derived from the Company's distribution rates for a given Decoupling Year for a Customer Class. The Company will use monthly distribution revenues and Actual Number of Customers to determine the Monthly Actual Base Revenue per Customer.

   b. Actual Number of Customers is the actual number of Equivalent Bills for the applicable Customer Class for the applicable month of the Decoupling Year.

   c. Billing Year is the 12-months commencing November 1 immediately following the completion of the Decoupling Year.

   d. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

e. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment. The two Customer Class Groups are as follows:

Residential Customer Class Group (CG1): defined as both Residential Non-Heating Customer Class and Residential Heating Customer Class, shall consist of all customers taking service pursuant to the Company's residential rate schedules. CG1 shall include customers taking service under rate schedules R-1, R-3, R-4, R-5, R-6 and R-7.

The Commercial and Industrial Customer Class Group (CG2): shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

f. Decoupling Year. The first Decoupling Year shall be the 10-month period from November 1, 2018 to August 31, 2019. Each subsequent Decoupling Year shall be the twelve months commencing September 1 through August 31.

g. Equivalent Bill. The number of days in the billing period of each customer's bill divided by 30.

h. Real-time normal weather adjustment is the difference between actual distribution revenue billed to each customer in each billing cycle for each month or portion thereof during the Winter Period, and what distribution revenue for each customer's bill would have been based on weather normalized therm deliveries for the same period. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

i. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

j. Winter Period. The time period from November 1 of a given year through April 30 of the following year inclusive.

k. Base Load Factor for each customer is the most recent two-year average daily delivered therms for actual bills rendered during the months of June through August for that customer. If a customer has less than two-year's billing history, then the customer's available history for the months of June through August will be used to calculate the average daily delivered therms; and if a customer has no billing history for the months of June through August, then the average daily delivered therms for the months of June through August for the rate schedule under which the customer is served will be used.

l. Base Usage for each bill is the current Base Load Factor times the number of days in billing period.

m. Heating Usage for each bill is the difference between the actual delivered therms for that bill less the Base Usage for that bill. If the calculated Heating Usage is less than zero, then the Heating Usage for that bill is set equal to zero.

n. Heating Degree Days (HDD) for each day is sixty-five (65) minus the average temperature in degrees Fahrenheit for that day. If the calculated HDD is less than zero, then the HDD for that day is set equal to zero.

o. Normal Heating Degree Days (Normal HDD) for each day is the thirty-year average HDD for that day.

p. Normal Weather Adjustment Slope (NWA Slope) for each bill is the Heating Usage divided by the sum of actual HDD during the billing period.

q. Normal Heating Usage for each bill is the NWA Slope times the sum of the Normal HDD for the billing period.

r. Normal Usage for each bill is the sum of the Base Usage and the Normal Heating Usage.

s. Normal Weather Normalization Factor (NWF) for each bill is

$$\mathrm{NWF} = \frac{\mathrm{DeliveryCharge_{Normal}}}{\mathrm{DeliveryCharge_{Actual}}} - 1$$

where Delivery Charge Normal is the calculated delivery charge for Normal Usage for the rate schedule applicable to that bill or portion thereof during the Winter Period and Delivery Charge Actual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Decoupling Year, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next Billing Year, effective November 1.

The Revenue Decoupling Adjustment shall be determined by calculating the monthly difference between the Benchmark Base Revenue per Customer times the actual number of Equivalent Bills for the applicable Customer Class and the Actual Base Revenue for that month. The sum of these monthly Revenue Decoupling Adjustments in the Decoupling Year shall be divided by forecasted Billing Year sales to derive the volumetric rate per therm to be applied to customers' bills in the Billing Year. The Revenue Decoupling Adjustment shall also include a reconciliation component for the previous Decoupling Year, which represents the difference between the accrued decoupling amount in the Decoupling Year compared to the actual revenues billed in the billing Year.

b. Revenue Decoupling Adjustment Formulas

$$\mathrm{RD_{CG}} = \sum_{\mathrm{RC=1}}^{\mathrm{RC=n}} \left[\left(\mathrm{BRPC_{T-1}} \text{ x } \mathrm{ACUSTS_{T-1}}\right) - \mathrm{AR_{T-1}}\right)\right]$$

And:

$$\mathrm{RDAF_{CG}} = \frac{\mathrm{RD_{CG}} + \mathrm{CGDEF_{t-1}}}{\mathrm{FTV_{CG}}}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}$ — The Actual Number of Equivalent Bills for the applicable Customer Class for the most recently completed Decoupling Year (T-1)

AR_{T-1} — The Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year, (T-1), as defined in Section 4(D). For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.

$BRPC_{T-1}$ — The Benchmark Base Revenue Per Equivalent Bill for the applicable Customer Class as determined in accordance with Section 4 (D) for the most recently completed Decoupling Year, stated on a monthly basis (T-1).

cg — Customer Class Groups as defined in Section 4(D).

$CG\mathrm{DEF}$ — The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.

FTV_{CG} — Forecast Throughput Volumes inclusive of all firm tariff throughput for the Billing Year.

rc — Rate Classes in a Customer Group.

RD_{CG} — The Revenue Decoupling adjustment to revenues, representing the sum of the monthly Revenue Decoupling Adjustments in the Decoupling Year.

$RDAF_{cg}$ — The Revenue Decoupling Adjustment Factor for the Billing Year.

6. Calculation of the RDAC Reconciliation Adjustments

Account 1163-1756 shall contain the accumulated difference between annual revenues and the Revenue Decoupling Adjustment, as calculated by multiplying the RDAF times firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues annually, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

The RDAF ($ per therm) shall be calculated annually for each Customer Group and shall be truncated at the nearest one one-hundredth of a cent per therm. The annual calculated Customer Group RDAF will be applied to the monthly firm tariff throughput for each customer in that particular Customer Group, effective November 1 of the given year.

8. Calculation of Normal Weather Adjustment

The Normal Weather Adjustment (NWA) for each bill is

$$\mathrm{NWA} = \mathrm{DeliveryCharge}_{\mathrm{Actual}} \times \mathrm{NWF}$$

where Delivery Charge Actual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

9. Application of the NWA to Customer Bills

The NWA charge or credit will be separately stated, and added to or subtracted from each bill as applicable. Each bill will have a separate line titled "Normal Weather Adj.," which line will include the total variable distribution charges, the NWF percentage, and the resulting charge or credit.

10. Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the LDAC. Such information shall include:

a. The calculation of the applicable revenue decoupling revenue dollar adjustment for the Decoupling Year by Customer Class Group.

b. The calculation of the revenue decoupling reconciliation dollar adjustment for the previous Decoupling Year by Customer Class Group.

c. The calculation of the proposed decoupling rate per therm for each customer class group to be applied in the Billing Year.

d. The calculation of the monthly Benchmark Base Revenue per Customer, to be utilized in the upcoming Decoupling Year. If distribution rates change during the Decoupling Year, the monthly Benchmark Base Revenue per Customer for the remaining months of the Decoupling Year will be revised and filed with the Commission.

E. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A\text{: } TPev}$$

where:

A: Tpev Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

RLIAP RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{RLIAP} RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{X} = CC^{X} + RDAC^{X} + ES + GREF^{x} + RCE + RLIAP$$

and:

ES^{X} = RHS + MGP

where:

$LDAC^{X}$ = Annualized class specific LDAC.

CC^{X} = Annualized class specific CC or EE Charge.

$RDAC^{X}$ = Annualized class specific RDAC.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^{X}$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

K. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

L. Amendments to Uniform System of Accounts.

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(E).

1930-1745 **<u>Rate Case Expense/Temporary Rates Reconciliation Adjustment</u>:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(F).

1169-1756 **<u>Residential Low Income Assistance Program Reconciliation Adjustment</u>:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 17(G).

1163-1756 **<u>Revenue Decoupling Adjustment Factor</u>:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(D).

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. <u>DEFINITIONS</u>

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. <u>Residential</u>: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

B. <u>Commercial</u>: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

C. <u>Industrial</u>: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

D. <u>Large Volume</u>: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

E. <u>Seasonal</u>: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

F. <u>Firm Sales Service</u>: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

G. <u>Firm Transportation Service</u>: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

H. <u>Plant Protection Gas:</u> Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not

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The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE AND NORMAL WEATHER ADJUSTMENT

A. Purpose. The purpose of the Local Distribution Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), Revenue Decoupling ~~Lost Revenues~~ Adjustment Clause~~Mechanism~~ ("RDAC~~LRAM~~"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), ~~recover gas restructuring expenses ("GRE"),~~ rate case expenses ("RCE"), Residential Low

Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time. The purpose of the Normal Weather Adjustment ("NWA") is to establish procedures that allow the Company, subject to the jurisdiction of NHPUC, to calculate and apply, for each customer on a monthly basis, the Weather Normalization Factor ("WNF").

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	**CC 17(C)**	**RDAC 17(D)**	**ES 17(E)**	**RCE 17(F)**	**RLIAP 17(G)**
Residential Non-Space Heating – R-1, R-5	1	1	X	1	X
Residential Space Heating – R-3, R-4, R-6, R-7	1	1	X	1	X
Small C&I – G-41, G-51, G-44, G-55	1	1	X	1	X
Medium C&I – G-42, G-52, G-45, G-56	1	1	X	1	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	1	1	X	1	X

Notes:
N/A Not applicable
X Applicable to all
1 Applicable to Non-Managed Expansion Program Customers

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

2. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

~~Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time.~~

~~B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."~~

~~**Applicability**~~	~~**CC 17(C)**~~	~~**LRAM 17(C.1)**~~	~~**ES 17(D)**~~	~~**GRE 17(E)**~~	~~**RCE 17(F)**~~	~~**RLIAP 17(G)**~~
~~Residential Non-Space Heating – R-1, R-5~~	~~2~~	~~2~~	~~X~~	~~N/A~~	~~2~~	~~X~~
~~Residential Space Heating – R-3, R-4, R-6, R-7~~	~~2~~	~~2~~	~~X~~	~~N/A~~	~~2~~	~~X~~
~~Small C&I – G-41, G-51, G-44, G-55~~	~~2~~	~~2~~	~~X~~	~~X~~	~~2~~	~~X~~
~~Medium C&I – G-42, G-52, G-45, G-56~~	~~2~~	~~2~~	~~X~~	~~X~~	~~2~~	~~X~~
~~Large C&I – G-43, G-53, G-54, G-46, G-57, G-58~~	~~2~~	~~2~~	~~X~~	~~X~~	~~2~~	~~X~~

~~**Notes:**~~
~~N/A Not applicable~~
~~X Applicable to all~~
~~1 Applicable to Non-Managed Expansion Program Customers~~
~~2 As ordered by the NHPUC~~

~~C. Conservation Charges Allowable for LDAC.~~

~~1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.~~

~~2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.~~

3. ~~Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.~~

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

D Revenue Decoupling Adjustment Clause.

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its rates for firm gas sales and firm transportation in order to reconcile Actual Base Revenue per Customer with Benchmark Based Revenue per Customer. The Company's RDAC eliminates the link between volumetric sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.. The purpose of the NWA is to adjust each customer's bill for the difference in delivery charges caused by the variation in actual HDDs from normal HDDs during the Winter Period.

2. Effective Date: The RDAC and NWA shall take effect beginning on November 1, 2018, and replace the Lost Revenue Adjustment Mechanism (LRAM) established in Order No. 25,932 (Docket No. DE 15-137).

3. Applicability: The Revenue Decoupling Adjustment Factor and NWA shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC and NWA.

4. Definitions: The following definitions shall apply throughout the RDAC and NWA:

   a. Actual Base Revenue is the actual revenue derived from the Company's distribution rates for a given Decoupling Year for a Customer Class. The Company will use monthly distribution revenues and Actual Number of Customers to determine the Monthly Actual Base Revenue per Customer.

   b. Actual Number of Customers is the actual number of Equivalent Bills for the applicable Customer Class for the applicable month of the Decoupling Year.

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~~4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.~~

~~5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.~~

~~6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.~~

~~C.1 Lost Revenue Adjustment Mechanism Allowable for LDAC.~~

~~1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Lost Revenue Adjustment Rate, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers lost revenue related to Energy Efficiency programs, pursuant to Order No. 25,932 in Docket DE 15-137, Energy Efficiency Resource Standard.~~

~~Applicability: A Lost Revenue Adjustment charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the New Hampshire Public Utilities Commission (the "Commission") as determined in accordance with the provision of this rate schedule. Such Lost Revenue Adjustment charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.~~

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~~Calculation of Lost Revenue Adjustment: The Lost Revenue Adjustment for each Rate Category will be derived by dividing the projected annual lost revenue, plus the reconciliation balance, by forecast firm annual throughput. The reconciliation balance shall reflect both actual and projected data, as necessary, through October of the prior rate period.~~

~~7. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the Lost Revenue Adjustment Rate applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.~~

~~8.~~5. ~~Reconciliation Adjustment: Account 1920-1863 shall contain the cumulative difference between the Lost Revenue Adjustment Rate revenues collected and actual costs, plus carrying charges. The~~

c. Billing Year is the 12-months commencing November 1 immediately following the completion of the Decoupling Year.

d. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

e. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment. The two Customer Class Groups are as follows:

Residential Customer Class Group (CG1): defined as both Residential Non-Heating Customer Class and Residential Heating Customer Class, shall consist of all customers taking service pursuant to the Company's residential rate schedules. CG1 shall include customers taking service under rate schedules R-1, R-3, R-4, R-5, R-6 and R-7.

The Commercial and Industrial Customer Class Group (CG2): shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

f. Decoupling Year. The first Decoupling Year shall be the 10-month period from November 1, 2018 to August 31, 2019. Each subsequent Decoupling Year shall be the twelve months commencing September 1 through August 31.

g. Equivalent Bill. The number of days in the billing period of each customer's bill divided by 30.

h. Real-time normal weather adjustment is the difference between actual distribution revenue billed to each customer in each billing cycle for each month or portion thereof during the Winter Period, and what distribution revenue for each customer's bill would have been based on weather normalized therm deliveries for the same period. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

i. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

j. Winter Period. The time period from November 1 of a given year through April 30 of the following year inclusive.

k. Base Load Factor for each customer is the most recent two-year average daily delivered therms for actual bills rendered during the months of June through August for that customer. If a customer has less than two-year's billing history, then the customer's available history for the months of June through August will be used to calculate the average daily delivered therms; and if a customer has no billing history for the months of June through August, then the average daily delivered therms for the months of June through August for the rate schedule under which the customer is served will be used.

l. Base Usage for each bill is the current Base Load Factor times the number of days in billing period.

m. Heating Usage for each bill is the difference between the actual delivered therms for that bill less the Base Usage for that bill. If the calculated Heating Usage is less than zero, then the Heating Usage for that bill is set equal to zero.

c. Heating Degree Days (HDD) for each day is sixty-five (65) minus the average temperature in degrees Fahrenheit for that day. If the calculated HDD is less than zero, then the HDD for that day is set equal to zero.

d. Normal Heating Degree Days (Normal HDD) for each day is the thirty-year average HDD for that day.

~~Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.~~

~~D. Environmental Surcharges ("ES") Allowable for LDAC.~~

~~1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.~~

~~2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.~~

~~3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate~~

~~The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.~~

~~4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.~~

~~5. Definitions:~~

~~Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result~~

~~6.~~4. ~~Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the~~

p. Normal Weather Adjustment Slope (NWA Slope) for each bill is the Heating Usage divided by the sum of actual HDD during the billing period.

q. Normal Heating Usage for each bill is the NWA Slope times the sum of the Normal HDD for the billing period.

r. Normal Usage for each bill is the sum of the Base Usage and the Normal Heating Usage.

s. Normal Weather Normalization Factor (NWF) for each bill is

$$NWF = \frac{DeliveryCharge_{Normal}}{DeliveryCharge_{Actual}} - 1$$

where *DeliveryChargeNormal* is the calculated delivery charge for Normal Usage for the rate schedule applicable to that bill or portion thereof during the Winter Period and *DeliveryChargeActual* is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Decoupling Year, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next Billing Year, effective November 1.

The Revenue Decoupling Adjustment shall be determined by calculating the monthly difference between the Benchmark Base Revenue per Customer times the actual number of Equivalent Bills for the applicable Customer Class and the Actual Base Revenue for that month. The sum of these monthly Revenue Decoupling Adjustments in the Decoupling Year shall be divided by forecasted Billing Year sales to derive the volumetric rate per therm to be applied to customers' bills in the Billing Year. The Revenue Decoupling Adjustment shall also include a reconciliation component for the previous Decoupling Year, which represents the difference between the accrued decoupling amount in the Decoupling Year compared to the actual revenues billed in the billing Year.

b. Revenue Decoupling Adjustment Formulas

$$RD_{CG} = \sum_{RC=1}^{RC=n} [(BRPC_{T-1}\, x\, ACUSTS_{T-1}) - AR_{T-1})]$$

And:

$$RDAF_{CG} = \frac{RD_{CG} + CGDEF_{t-1}}{FTV_{CG}}$$

Where the terms in the above equation have the following meanings:

~~Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.~~

ISSUED: October~~May~~ 0~~18~~1, 2018 ISSUED BY: /s/Susan L. Fleck
Susan L. Fleck
EFFECTIVE: November~~May~~ 01, 2018 TITLE: President

Authorized by NHPUC Order No. 26,122 dated April 27, 2018, in Docket No. DG 17-048

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7. ~~Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.~~

8. ~~Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.~~

E. ~~Expenses Related to Gas Restructuring.~~

1. ~~Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates on an annual basis for the recovery of NHPUC-approved costs associated with the Gas Restructuring Collaborative (Docket DE 98-124).~~

2. ~~Applicability: The Gas Restructuring Expenses ("GRE") shall be applied to all firm tariffed customers eligible to receive delivery service from the Company as determined in accordance with the provisions of Section 17(F) of this clause. The GRE shall be determined annually by the Company as defined below, subject to review and approved by the NHPUC as provided for in this clause.~~

3. ~~GRE Allowable for LDAC: Costs associated with the Gas Restructuring Collaborative (DE 98-124), including, but not limited to, any legal, consulting, customer focus group(s) and survey(s), customer education campaign(s), materials and advertising, subject to review and approval by the NHPUC.~~

4. ~~Effective Date of GRE Charge: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the GRE applicable to all consumption of tariffed customers eligible to receive delivery service for the subsequent twelve month period commencing with the calendar month of November.~~

5. ~~Definition: Gas Restructuring Initiatives are activities facilitating the development, design and implementation of unbundled services for all customers.~~

6. ~~GRE Factor Formula:~~

~~GREF = GRE + RAGRE~~
~~A: TPev~~

~~where:~~

~~A:Tpev~~ ~~Forecast Annual Throughput Volumes of all tariffed customers eligible to receive firm delivery-only service from the Company.~~

~~GRE~~ ~~Gas Restructuring Expenses as defined in Section 17(F).05.~~

$ACUSTS_{T-1}$	The Actual Number of Equivalent Bills for the applicable Customer Class for the most recently completed Decoupling Year (T-1)
AR_{T-1}	The Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year, (T-1), as defined in Section 4(D). For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.
$BRPC_{T-1}$	The Benchmark Base Revenue Per Equivalent Bill for the applicable Customer Class as determined in accordance with Section 4 (D) for the most recently completed Decoupling Year, stated on a monthly basis (T-1).
cg	Customer Class Groups as defined in Section 4(D).
$CGDEF$	The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.
FTV_{CG}	Forecast Throughput Volumes inclusive of all firm tariff throughput for the Billing Year.
rc	Rate Classes in a Customer Group.
RD_{CG}	The Revenue Decoupling adjustment to revenues, representing the sum of the monthly Revenue Decoupling Adjustments in the Decoupling Year.
$RDAF_{cg}$	The Revenue Decoupling Adjustment Factor for the Billing Year.

6. Calculation of the RDAC Reconciliation Adjustments

Account 1163-1756 shall contain the accumulated difference between annual revenues and the Revenue Decoupling Adjustment, as calculated by multiplying the RDAF times firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues annually, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

The RDAF ($ per therm) shall be calculated annually for each Customer Group and shall be truncated at the nearest one one-hundredth of a cent per therm. The annual calculated Customer Group RDAF will be applied to the monthly firm tariff throughput for each customer in that particular Customer Group, effective November 1 of the given year.

8. Calculation of Normal Weather Adjustment

The Normal Weather Adjustment (NWA) for each bill is

$$\mathrm{NWA} = \mathrm{DeliveryCharge}_{\mathrm{Actual}} \times \mathrm{NWF}$$

where DeliveryChargeActual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

ISSUED: October~~May~~ 0~~1~~8, 2018 ISSUED BY: /s/Susan L. Fleck
Susan L. Fleck
EFFECTIVE: November~~May~~ 01, 2018 TITLE: President

Authorized by NHPUC Order No. 26,122 dated April 27, 2018, in Docket No. DG 17-048

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9. Application of the NWA to Customer Bills

~~RA_{GRE} Gas Restructuring Expense Reconciliation Adjustment - Account 1920-1744, inclusive of the associated Account 1920-1744 interest, as outlined in Section 17(E)(7).~~

~~7. Reconciliation Adjustments: Account 1920-1744 shall contain the accumulated difference between revenues toward Gas Restructuring Expenses as calculated by multiplying the Gas Restructuring Expense Factor ("GREF") times monthly volumes of customers eligible to receive firm delivery service and Gas Restructuring expenses allowed, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end-of-month balance.~~

~~8. Application of GREF to Bills: The GREF ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.~~

~~9. Information to be Filed with the NHPUC: Information pertaining to the Gas Restructuring Expenses shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual GREF filing shall be required on or before the first business day in September of each year. The GREF filing shall contain the calculation of the new annual GREF to become effective November 1 and shall include the updated annual Gas Restructuring Expense reconciliation balance.~~

~~F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.~~

~~1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.~~

~~2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.~~

~~3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.~~

~~4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.~~

~~5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.~~

~~6.~~10. ~~Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery~~

The NWA charge or credit will be separately stated, and added to or subtracted from each bill as applicable. Each bill will have a separate line titled "Normal Weather Adj.," which line will include the total variable distribution charges, the WNF percentage, and the resulting charge or credit.

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9. Information to be Filed with the Commission

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Information pertaining to the RDAC will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the LDAC. Such information shall include:

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a. The calculation of the applicable revenue decoupling revenue dollar adjustment for the Decoupling Year.

b. The calculation of the revenue decoupling reconciliation dollar adjustment for the previous Decoupling Year.

c. The calculation of the proposed decoupling rate per therm for each customer class group to be applied in the Billing Year.

d. The calculation of the monthly Benchmark Base Revenue per Customer, to be utilized in the upcoming Decoupling Year. If distribution rates change during the Decoupling Year, the monthly Benchmark Base Revenue per Customer for the remaining months of the Decoupling Year will be revised and filed with the Commission.

E. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.~~among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.~~

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~~Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.~~

~~At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.~~

~~Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.~~

~~Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.~~

~~G. Recoverable Residential Low Income Assistance Program Costs.~~

~~Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.~~

~~Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.~~

~~Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.~~

~~RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP~~

4. *Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.*

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5. *Definitions:*

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. *Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.*

7. *Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.*

8. *Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.*

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

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1. *Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.*

2. *Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.*

3. *Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.*

~~Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.~~

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ISSUED:	October~~May~~ 0~~18~~, 2018	ISSUED BY:	/s/Susan L. Fleck Susan L. Fleck
EFFECTIVE:	November~~May~~ 01, 2018	TITLE:	President

Authorized by NHPUC Order No. 26,122 dated April 27, 2018, in Docket No. DG 17-048

~~MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.~~

~~GREF* = Total firm annualized class specific Gas Restructuring Expense Factor.~~

~~RCE = Rate Case Expense Factor.~~

~~RLIAP = Residential Low Income Assistance Program Rate~~

~~J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).~~

~~J. Other Rules.~~

~~1. (1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.~~

~~1. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.~~

~~2. The Company may implement an amended LDAC with the NHPUC approval at any time.~~

~~3. The NHPUC may, at any time, require the Company to file an amended LDAC.~~

~~4. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.~~

~~K. Amendments to Uniform System of Accounts.~~

~~1920-1744 **Gas Restructuring Expense Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(E).~~

~~1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C).~~

~~1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(D).~~

~~1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the~~

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3. *Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.*

4. *RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.*

5. *RLIAP Factor Formula*

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A: TPev}$$

where:

A: Tpev — Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

RLIAP — RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{RLIAP} — RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. *Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.*

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

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I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^X = CC^X + RDAC^X + ES + GREF^x + RCE + RLIAP$$

and:

ISSUED: ~~May~~ October ~~18~~ 01, 2018 — ISSUED BY: /s/Susan L. Fleck, Susan L. Fleck

EFFECTIVE: ~~May~~ November 01, 2018 — TITLE: President

Authorized by NHPUC Order No. 26,122 dated April 27, 2018, in Docket No. DG 17-048

ES^X = RHS + MGP

where:

$LDAC^X$ = Annualized class specific LDAC.

CC^X = Annualized class specific CC or EE Charge.

$RDAC^X$ = Annualized class specific RDAC.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^X$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

H. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

I. Other Rules.

1. *The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.*

2. *Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.*

3. *The Company may implement an amended LDAC with the NHPUC approval at any time.*

4. *The NHPUC may, at any time, require the Company to file an amended LDAC.*

5. *The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.*

J. Amendments to Uniform System of Accounts.

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(C).

~~H.~~K. 1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(E).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 17(G).

1163-1756 **Revenue Decoupling Adjustment Factor:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(D).

~~difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(F).~~

~~1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(G).~~

~~1163-1756 **Lost Revenue Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C.1).~~

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

B. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

C. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

D. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

E. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

F. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

G. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

H. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not

CHAIRMAN
Martin P. Honigberg

COMMISSIONERS
Kathryn M. Bailey
Michael S. Giaimo

EXECUTIVE DIRECTOR
Debra A. Howland

THE STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION
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1-800-735-2964

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FAX (603) 271-3878

Website:
www.puc.nh.gov

October 31, 2018

Re: DG 17-048, Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Petition for Permanent and Temporary Rates
Order on Rehearing

To the Parties:

In the rehearing phase of this proceeding, Liberty requested approval of base delivery rate changes and Local Delivery Adjustment Charge (LDAC) changes effective November 1, 2018. Liberty also requested approval of its proposed decoupling tariff effective November 1. These rate changes and the decoupling tariff were supported by Staff at the October 19, 2018 hearing in this matter.

The Commission is preparing an Order approving Liberty's requested rate changes and its decoupling tariff effective November 1, 2018. The Order is expected to be issued shortly.

In order to allow customer billing to proceed in the ordinary course, the Commission has approved the following in advance of issuing a more formal Order:

- Liberty shall decrease its LDAC effective November 1, 2018 to pass back to customers $280,147 for the adjustments detailed on Exh. 88.

- Liberty shall decrease its base delivery rates effective November 1, 2018 to pass back to customers $1,070,435 annually for the adjustment detailed on Exh. 81.

- Liberty's illustrative decoupling tariff, as updated in this proceeding, is hereby approved.

Sincerely,

Debra A. Howland
Executive Director

cc: Service List DG 17-048

SERVICE LIST - EMAIL ADDRESSES- DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

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stower@nhla.org

Docket #: 17-048-1 Printed: October 31, 2018

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 17-048

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

Petition for Permanent and Temporary Rates

Order on Rehearing

O R D E R N O. 26,187

November 2, 2018

APPEARANCES: Michael J. Sheehan, Esq., on behalf of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities; the Office of the Consumer Advocate by D. Maurice Kreis, Esq., on behalf of residential ratepayers; and Paul B. Dexter, Esq., on behalf of Commission Staff.

This order resolves all pending issues raised on rehearing. In this order, the Commission approves lower distribution rates and lower LDAC rates for Liberty than were approved in Order No. 26,122. The lower rates result from new information and reductions in income tax expense following enactment of the "Tax Cuts and Jobs Act of 2017." Further, the Commission approves Liberty's decoupling tariff and customer education plan.

I. PROCEDURAL HISTORY

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty or the Company) filed a Petition for Permanent and Temporary Rates on April 28, 2017. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2017/17-048.html. The Commission approved temporary rates in Order No. 26,035 (June 30, 2017) effective July 1, 2017, increasing the Company's revenue by $6,750,000 annually. On April 27, 2018, the Commission issued Order

No. 26,122 (the April Order) approving a permanent rate increase of $8,060,117 and a step increase of $4,729,953, both for effect May 1, 2018. The April Order included approval of a new rate design with significant reductions in customer charges and corresponding increases in volumetric charges. It also approved a decoupling proposal applicable to all rate classes.

On May 25, 2018, Liberty filed a Motion for Rehearing to determine whether the April Order's rate design changes were intended to go into effect on May 1, 2018. Liberty claimed that, because it implemented the rate design changes on May 1, 2018, it would collect $3,079,391 less in 2018 than the Commission had approved. Liberty sought approval to recover this perceived shortfall through the Rate Case Temporary Rate Reconciliation component of the Local Delivery Adjustment Charge (LDAC) over an 18-month period commencing July 1, 2018.

In Order No. 26,149 (June 22, 2018) (the June Order), the Commission granted rehearing in part, and requested additional information to evaluate Liberty's claimed shortfall. *See* Order No. 26,149 at 7-9 and Appendix 1. In the June Order, the Commission clarified that Liberty would not (and should not have expected to) collect its full approved revenue requirement increase of $8,060,117 in calendar year 2018, because the recoupment provision (designed to collect the difference between temporary rates and permanent rates) extended through 2019. June Order at 7. The Commission also requested additional information to refine the recoupment calculation approved in the April Order at Appendix 5. June Order at 8-9 and Appendix 2. Liberty filed information on July 9, 2018. Hearing Exhibit (Exh.) 83. Those materials were updated several times. *See* Exh. 87 (concerning the claimed revenue shortfall); Exh. 80 and 86 (submitted July 17, 2018); and Updated Exhs. 80 and 86 (submitted October 10, 2018) (concerning recoupment).

On June 11 and October 19, 2018, Liberty filed customer education materials related to decoupling. Exh. 91. On August 9, 2018, Liberty filed a proposal to reflect the impacts of the tax law changes in its LDAC rates. Exh. 89.

The Commission held hearings on July 17, October 19, and October 22, 2018. At the hearing on October 19, Liberty presented (and Staff supported) a distribution rate reduction to correct an error that Liberty made in calculating the distribution rates it had put into effect on May 1, 2018. *See* Exh. 88; Hearing Transcript of October 19, 2018 (10/19/18 Tr.) at 25-32. Liberty also presented (and Staff supported) approval of reduced LDAC rates that reflected, among other adjustments, a refined recoupment calculation presented on Updated Exh. 86, and several other adjustments set forth on Exh. 88 related to recoupment and the treatment of Keene revenues, the distribution rate error, recovery of audit costs, and tax expense reductions.

II. POSITIONS OF THE PARTIES AND STAFF

A. Liberty

1. <u>Rates</u>

As stated above, in its Motion for Rehearing, Liberty requested approval to increase its LDAC to collect $3,079,391 over the remainder of 2018 and all of 2019 to address a perceived shortfall in 2018 income that Liberty believed would result from the timing of rate design changes approved in the April Order. At the July 17 hearing, Liberty reduced this claim to $2,171,000 acknowledging that the rate design impacts would be dampened when the months of November and December 2018 were included in the calculation, because the new rate design produces increased revenues in colder months**.** Hearing Transcript of July 17, 2018 (7/17/18 Tr.) at 60-62.

At the July 17 hearing, Liberty also presented a second rate design theory in support of its request to collect an additional $2 million (approximately) through the LDAC. The second theory focused on the refined recoupment calculation the Commission requested in the June Order. As directed, Liberty calculated the revenue that had been produced by the temporary rates that were in effect on July 1, 2017, through April 30, 2018, and compared that amount to the revenue that would have been received if the permanent rates had been in effect over that same period (assuming consistent billing determinants). Liberty submitted that analysis on July 9 (Exh. 80 and 83). The analysis attempted to demonstrate that Liberty would have collected $3,293,820 more in revenues had the permanent rates been in effect over the 10-month temporary rate period. Liberty compared that figure to the recoupment amount allowed in the April Order at Appendix 5 of $1,326,355 and concluded that the difference of $1,967,465 should be collected through the LDAC over the remaining months in 2018 and all of 2019. Liberty attributed the large difference in these two recoupment amounts to the rate design changes ordered in the April Order as well as other items that would require more study. 7/17/18 Tr. at 86 and 99-101.[1]

On October 10, Liberty provided updated versions of Exhibits 80 and 86. Updated Exh. 86 showed a refined recoupment amount of $1,661,022, compared to the recoupment amount in the April Order of $1,326,355 (an increase of $334,667), which Liberty stated should be recovered through the LDAC. 7/17/18 Tr. at 14.

At the October 19 hearing, Liberty proposed several other distribution rate reductions and LDAC reductions. 10/19/18 Tr. at 13-16. Regarding its distribution rates, Liberty discovered in the course of reconciling the two recoupment calculations (Exhibit 85) that it had over-stated the

[1] Liberty also expressed concern that the figures presented on Exhs. 79, 80, and by extension, 86, required corrections. The Commission directed Liberty to review those exhibits and provide updated versions, which Liberty did on October 10, 2018. 7/17/18 Tr. at 99-101.

rates that were charged effective May 1, 2018. The over-statement was caused by Liberty's failure to account for sales from the end of year customers adjustment, as required by the April Order at 10. Liberty proposed to reduce distribution rates effective November 1, 2018, by $1,070,435 (on an annual basis), and to refund $319,660 through the LDAC to refund the amount over-collected from May through October. Exhs. 81 and 88.

Liberty's other proposed adjustments to the LDAC were shown in Exh. 88. First, Liberty added $334,667 to the LDAC to reflect the difference between the two recoupment calculations. Second, Liberty added $160,208 to recover a portion of the costs Liberty incurred from a Commission mandated audit. Third, Liberty deducted $455,362 from the LDAC to ensure that Liberty did not also recoup from EnergyNorth customers the incremental revenues that Keene customers paid from July 1, 2017, through April 30, 2018, *i.e.*, the difference between Keene rates and EnergyNorth rates prior to the rate consolidation approved in the April Order at 38.

The net of the proposed adjustments to the LDAC was a reduction of $280,147 to be passed back to customers over a 12-month period beginning November 1, 2018. Liberty stated that if the Commission approved rates that reflected all the above adjustments, that approval would fully resolve the issues raised in Liberty's Motion for Rehearing. 10/19/18 Tr. at 58.

2. <u>Decoupling Tariffs</u>

On June 11, 2018, Liberty submitted an illustrative tariff to implement decoupling, including real-time weather normalization, as directed in the April Order at 45-46. Liberty submitted an updated version on October 22, after receiving input from Staff and the OCA. At the October 19 hearing, Liberty agreed to make additional changes suggested by the Commission.

3. Decoupling Customer Education Materials (including information on Customer Bills)

Also on June 11, Liberty filed draft customer notice and education materials related to decoupling; and Liberty filed additional materials on October 17, 2018. Exh. 91. At the October 22 hearing, Liberty indicated that, based on recent conversations with Staff, it had agreed to make certain changes to the materials (some of which were already made by the October 22 hearing). Liberty further stated that it had agreed to work with Staff to develop additional customer education materials for its website, such as heating degree day information, both current and normal, as well as other materials related to the normal weather adjustment and energy efficiency.

Liberty stated that it did not support putting customer specific base load usage on its bills at this time, due to a limited amount of space available on the bill and the time and expense of required computer programming. Similarly, Liberty did not support providing information on the bill to indicate whether the customer's billing month was colder or warmer than normal. Liberty agreed to work with Staff and the OCA to refine what useful information could be included on the bill and at what cost. Hearing Transcript of October 22, 2018 (10/22/18 Tr.) at 9-15, 33-39.

4. Decoupling Programming Costs

Liberty stated that it did not view the April Order as placing a $50,000 cap on the amount it could recover from customers related to programming costs. Liberty claimed that the $50,000 cap was part of a settlement that the Commission did not approve and does not apply. Liberty stated that it intended to seek full recovery of the decoupling-related programming costs in its next rate case. 10/19/18 Tr. at 62-66.

B. OCA

The Office of the Consumer Advocate (OCA) reiterated its support for decoupling and its expectation that Liberty would be a "champion of energy efficiency" as a result of decoupling. The OCA also cautioned against micro-managing the introduction of decoupling, which it views as Liberty's job to do prudently. The OCA stated its opinion that the $50,000 cap on recovery of decoupling programming expenses is in place, and requested that the Commission state in its order that the cap applies. 10/22/18 Tr. at 59-62.

C. Staff

1. Rates

As stated in the June Order, Staff opposed the original theory Liberty put forth on rehearing concerning the rate design impacts of the April Order. Staff maintained that the approved rates would produce the revenue intended ($8,070,112 annually, before considering tax reform) over the intended time period (12 months beginning May 1, 2018).

Concerning Liberty's second theory for additional recovery, Staff agrees the recoupment calculation on Updated Exh. 86 is more accurate. Staff also supports reducing the recoupment amount shown on Updated Exh. 86 by $455,362 to prevent Liberty from recovering from EnergyNorth customers the higher revenues that were collected from Keene customers during the temporary rate period.

Further, Staff supports a reduction in distribution rates of $1,070,435 on an annual basis to correct the error that Liberty made in calculating the rates that were implemented in May 2018. Staff agrees Liberty overstated rates because Liberty included the revenue from the end of the year customers adjustment but did not include corresponding sales volumes, as required by the April Order at 9-10; and supports the corollary LDAC reduction of $319,660 to reverse the over-charges that occurred from May 1 through October 31, 2018. Exh. 88.

Staff also supports Liberty's proposed reduction of $291,806 to distribution rates to pass back to customers the permanent portion of the reductions in income taxes. This reduction adjusts the tax placeholder amount of $2,394,065 used to calculate distribution rates put into effect on May 1, 2018. Exh. 89 at 14-17. Staff agrees with Liberty's assessment (Exh. 89 at 14) that the April Order contemplated that adjustments to the tax placeholder amount would be made through the LDAC, and supports Liberty's proposal to reflect the adjustments as changes in base rates, because they are recurring tax savings. Adjustments through the LDAC would need to be made annually. By handling these adjustments in base rates, only one set of changes is needed and thus this method is more efficient.

Finally, Staff supports Liberty's request to use $160,208 of the over-collection in tax expense between January 1 and April 30, 2018, to recover a portion of the costs Liberty incurred for the audit that followed its last rate case. Staff notes that 75 percent of the audit costs will be recovered in this fashion and the remaining 25 percent will be paid for by Liberty, and not passed on to its customers.

2. Decoupling

Staff indicated support for the decoupling tariffs filed on October 19, 2018, with the minor adjustments Liberty made to the tariff at the October 19 hearing. Exh. 92.

3. Decoupling Customer Education Materials (including information on Customer Bills)

Staff indicated general support for the customer education materials Liberty has provided so far. Staff has not yet seen other materials, including an energy efficiency awareness plan and a detailed web page on the Normal Weather Adjustment (NWA) calculation. Staff continues to recommend that Liberty include a statement on each customer's bill indicating how the weather in the recent billing period compared to normal weather.

4. Decoupling Programming Costs

Staff took no position on the $50,000 cap on decoupling programming costs.

III. COMMISSION ANALYSIS

A. Rates

We reject Liberty's first theory for recouping approximately $3 million (revised down to $2 million) through the LDAC to make up for shortfalls that it claimed it would experience in 2018. We remain unpersuaded that we should allow additional LDAC revenues in 2018 to offset the impact that rate design shifts may have on 2018 revenues. The revenue impact of revised utility rates should be evaluated by looking at the year immediately following the date of rate implementation (in this case the 12 months beginning May 1, 2018). We asked Liberty to perform such an analysis of the approved rates. Exhibit 87 confirms that the approved (corrected) rates implemented May 1, 2018, would produce $8,060,117 over 12 months, assuming no reduction in tax expense and assuming test year adjusted billing determinants. 10/19/18 Tr. at 59-60.

Concerning Liberty's second theory (additional LDAC recovery based on the refined recoupment method), we approve Liberty's proposal, as supported by Staff. The refined methodology more accurately calculates the revenues that would have actually been collected had the permanent rates been in effect during the temporary rate period. As such, the refined recoupment calculation accounts for the impact of the significant rate design changes that were implemented in the permanent rates. In addition, the refined recoupment calculation captures the impact of sales growth that occurred during the temporary rate period. 10/19/18 Tr. at 45-48.

We approve Liberty's proposal for handling tax reductions, including the changes to distribution rates for the permanent portion of the tax cuts (instead of LDAC reductions called for in the April Order). We agree that one permanent change is more efficient and less confusing to customers than a series of annual LDAC reductions.

Concerning the $1,070,435 annual reduction to underlying base rates that have been billed since May 1, we approve Liberty's approach, including the LDAC pass back of the one-time over-collection from May 1 through October 31, 2018, of $319,660, with a final reconciliation once October sales are known.

B. Decoupling Tariff

We reviewed Liberty's illustrative tariff filed on June 11 as well as the revised version filed October 22. We find that the October 22 tariff adequately describes the decoupling mechanism, including the real-time weather adjustment, and we approve it. We require Liberty to file a compliance version of this tariff within 15 days of this order.

C. Decoupling Education Plan

We reviewed Liberty's education materials filed on June 11 and the additional materials filed October 17, which included a bill insert, a newsletter, and links to a decoupling web page including Frequently Asked Questions and a video explaining decoupling. We approve the materials that have been presented to us to date. We direct Liberty to work with Staff to improve these education materials as the decoupling process unfolds over the next 12 months. In addition, we require Liberty to report back to the Commission's Director of Consumer Services and External Affairs on Liberty's and its customers' experience during the first 90 days of decoupling. The report shall be filed no later than February 28, 2019, and shall include an assessment of customer reaction to decoupling. At a minimum, the report should include a tally of all customer inquiries and complaints about decoupling and how Liberty responded to those inquiries and complaints. Liberty should also include any additional materials that were (or will be) developed to address those inquires and complaints.

At the October 22 hearing, Liberty admitted to distributing most of the materials (bill insert, newsletter, website, and video) to its customers without Commission approval, which we specifically required. *See* Order No. 26,122 at 46. Liberty cited a lack of response by Staff and the Commission to its June 11 filing of draft materials, and the impending November 1 deadline for implementing decoupling as its reasons for distributing the materials without the necessary approval. Liberty's attempt to shift blame for its failure to meet its obligation is inappropriate and is not a valid excuse for violating an order. It was Liberty's responsibility to obtain prior approval, and Liberty should have pursued that approval more vigorously if timing were an issue. We consider Liberty's actions to have been a direct, knowing, and purposeful violation of the April Order. RSA 365:41 allows for fines in situations where a utility violates an order of the Commission. Although we opt not to issue a fine in this first instance, we will not hesitate to impose fines should Liberty disregard any other Commission order.

At the October 22 hearing, we discussed two related, unresolved items. First, we expressed an interest in having Liberty display each customer's base usage on its bill. Base usage is needed for a customer to calculate the NWA, which will be on every customer's bill. Exh. 61. Second, we expressed a desire for Liberty to include a message on each bill indicating how weather during the past billing period compared to normal weather. While Liberty did not object in concept to adding this information to customers' bills, it cautioned that such changes would take time to develop and would be costly to implement. 10/22/18 Tr. at 13-15 and 33-39. Based on the testimony, we will not require Liberty to add this information to its bills, at this time. We believe, however, that this information is necessary for customers to be able to verify the accuracy of their bills. Accordingly, we require Liberty to work with Staff and the OCA to develop a method to make this information available on Liberty's website. Further, the next time Liberty updates its billing system or bill format, we direct Liberty to work with the Commission's Director of External Affairs and Consumer Services to determine the costs and benefits of including such information on its bills; and, if such information can be added cost effectively at that time, to do so. Prior to making such bill changes, Liberty shall report its plans to the Commission.

At the October 22 hearing, Liberty reviewed a list of decoupling communication efforts proposed by Staff and which it had agreed to undertake. The list included developing a web page to provide information about how the NWA works, including how base usage is calculated and how a customer could obtain the individualized usage needed to calculate the NWA. 10/22/18 Tr. at 12; Exh. 93. In addition to what Liberty has agreed to do, we require the Company to develop a calculator that will assist a customer in verifying that the NWA was calculated accurately. Also on the list, Liberty agreed to develop a web page showing current heating degree day information and 30 year historic (normal) information, for Keene and Manchester. We direct Liberty to indicate on this page, for each billing cycle, how the most recent monthly weather compared to normal. We direct Liberty to work with Staff to develop these web page additions and to make the additions a priority so that customers can use the information as soon as possible after decoupling goes into effect.

D. Decoupling Programming Costs

The cost of decoupling-related programming changes was raised at the October 22 hearing, which led to a discussion of whether Liberty's recovery of any such billing system upgrades and software costs was capped at $50,000 by the April Order. To the extent there was any question, we confirm that the cap was included in the Commission's approval of decoupling in the April Order. The Commission adopted and approved the decoupling proposal contained in the Liberty/OCA Settlement (Exhibit 29 at 11), which unambiguously contained that cap. Exh. 29 at 11 ("Any costs above $50,000 will be absorbed by the Company"); Order No. 26,122 at 44-45. The Liberty/OCA panel testified in detail that $50,000 should be enough to cover the programming costs if Liberty negotiates with its billing vendor, and that the cap would serve as a useful tool for helping Liberty minimize these costs. 3/23/18 AM Tr. at 49-50.

E. Auditing the NWA

To allow the Commission's Audit Division to verify that Liberty correctly calculates the NWA over its broad spectrum of customers, we require that Liberty, starting in December 2018 and continuing for 12-months, provide to the Audit Division two randomly selected residential bills and one randomly selected non-residential bill from each billing cycle for each of the 12 months. Liberty shall also provide sufficient information, such as base usage by customer, to allow the Audit Division to review these bills for accuracy.

Based upon the foregoing, it is hereby

ORDERED, that Liberty shall decrease its LDAC effective November 1, 2018, to pass back to customers $280,147 for the adjustments detailed on Exh. 88; and it is

FURTHER ORDERED, that Liberty shall decrease distribution rates effective November 1, 2018, to pass back to customers $1,070,435 annually for the adjustment detailed on Exh. 81; and it is

FURTHER ORDERED, that Liberty shall file compliance LDAC and distribution rate tariffs consistent with this Order within 15 days of this Order; and it is

FURTHER ORDERED, that Liberty's illustrative decoupling tariff, as updated in this proceeding, is hereby approved; and it is

FURTHER ORDERED, that Liberty shall file a compliance decoupling tariff consistent with this Order within 15 days of this Order; and it is

FURTHER ORDERED, that Liberty's decoupling educational materials submitted to date are hereby approved; and it is

FURTHER ORDERED, that Liberty shall continue to develop and disseminate decoupling educational materials as described on Exhibit 93; and it is

FURTHER ORDERED, that Liberty shall report back to the Commission's Director of Consumer Services and External Affairs about its first 90 days of decoupling, as discussed herein; and it is

FURTHER ORDERED, that, during the development of any updates to Liberty's billing system or bill format, Liberty shall work with the Commission's Director of External Affairs and Consumer Services to determine whether additional information related to base usage and weather can be added to the bill in a cost effective manner, Liberty shall report its determination to the Commission, and Liberty shall make such bill changes if it is cost-effective to do so; and it is

FURTHER ORDERED, that each month, for 12 months beginning in December of 2018, Liberty shall provide to the Commission's Audit Division two randomly selected residential bills and one randomly selected non-residential bill from each billing cycle for the previous month, as well as sufficient information to allow the Audit Division to review these bills for accuracy; and it is

FURTHER ORDERED, that Liberty work with Staff and the Office of Consumer Advocate to develop a web page to provide all necessary information for customers to understand and accurately verify their individual bills as described above; and it is

FURTHER ORDERED, that Liberty's obligations under IR 18-001 to file a proposal to address the effects of tax law changes have been satisfied; and it is

FURTHER ORDERED, that Liberty shall include in its next distribution rate case, a proposal for addressing the impact of tax law changes on its accumulated deferred income tax balances.

By order of the Public Utilities Commission of New Hampshire this second day of November, 2018.

Martin P. Honigberg Chairman	Kathryn M. Bailey Commissioner	Michael S. Giaimo Commissioner

Attested by:

Margaret L. Raymond
Assistant Secretary

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

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Docket #: 17-048-1 Printed: November 02, 2018

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

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The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE AND NORMAL WEATHER ADJUSTMENT

A. Purpose. The purpose of the Local Distribution Adjustment Clause (“LDAC” or this “Clause”) is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges (“CC”), Revenue Decoupling Adjustment Factor (“RDAF”), Winter Period Surcharges (“WPS”), Environmental Surcharges (“ES”) including the Relief Holder Surcharge (“RHS”) and the Manufactured Gas Program Surcharge (“MGP”), rate case expenses (“RCE”), Residential Low

Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time. The purpose of the Normal Weather Adjustment ("NWA") is to establish procedures that allow the Company, subject to the jurisdiction of NHPUC, to calculate and apply, for each customer on a monthly basis, the Normal Weather Factor ("NWF").

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	CC 17(C)	RDAF 17(D)	ES 17(E)	RCE 17(F)	RLIAP 17(G)
Residential Non-Space Heating – R-1, R-5	1	1	X	1	X
Residential Space Heating – R-3, R-4, R-6, R-7	1	1	X	1	X
Small C&I – G-41, G-51, G-44, G-55	1	1	X	1	X
Medium C&I – G-42, G-52, G-45, G-56	1	1	X	1	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	1	1	X	1	X

Notes:
N/A Not applicable
X Applicable to all
1 Applicable to Non-Managed Expansion Program Customers

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

D Revenue Decoupling Adjustment Factor.

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAF") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its rates for firm gas sales and firm transportation in order to reconcile Actual Base Revenue per Customer with Benchmarked Base Revenue per Customer. The Company's RDAF eliminates the link between volumetric sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.. The purpose of the NWA is to adjust each customer's bill for the difference in delivery charges caused by the variation in actual HDDs from normal HDDs during the Winter Period.

2. Effective Date: The RDAF and NWA shall take effect beginning on November 1, 2018, and replace the Lost Revenue Adjustment Mechanism (LRAM) established in Order No. 25,932 (Docket No. DE 15-137).

3. Applicability: The Revenue Decoupling Adjustment Factor and NWA shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAF and NWA.

4. Definitions: The following definitions shall apply throughout the RDAF and NWA:

   a. Actual Base Revenue is the actual revenue derived from the Company's distribution rates for a given Decoupling Year for a Customer Class. The Company will use monthly distribution revenues and Actual Number of Customers to determine the Monthly Actual Base Revenue per Customer.

   b. Actual Number of Customers is the actual number of Equivalent Bills for the applicable Customer Class for the applicable month of the Decoupling Year.

   c. Billing Year is the 12-months commencing November 1 immediately following the completion of the Decoupling Year.

   d. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

e. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment. The two Customer Class Groups are as follows:

Residential Customer Class Group (CG1): defined as both Residential Non-Heating Customer Class and Residential Heating Customer Class, shall consist of all customers taking service pursuant to the Company's residential rate schedules. CG1 shall include customers taking service under rate schedules R-1, R-3, R-4, R-5, R-6 and R-7.

The Commercial and Industrial Customer Class Group (CG2): shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

f. Decoupling Year. The first Decoupling Year shall be the 10-month period from November 1, 2018 to August 31, 2019. Each subsequent Decoupling Year shall be the twelve months commencing September 1 through August 31.

g. Equivalent Bill. The number of days in the billing period of each customer's bill divided by 30.

h. Real-time normal weather adjustment is the difference between actual distribution revenue billed to each customer in each billing cycle for each month or portion thereof during the Winter Period, and what distribution revenue for each customer's bill would have been based on weather normalized therm deliveries for the same period. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

i. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

j. Winter Period. The time period from November 1 of a given year through April 30 of the following year inclusive.

k. Base Load Factor for each customer is the most recent two-year average daily delivered therms for actual bills rendered during the months of June through August for that customer. If a customer has less than two-year's billing history, then the customer's available history for the months of June through August will be used to calculate the average daily delivered therms; and if a customer has no billing history for the months of June through August, then the average daily delivered therms for the months of June through August for the rate schedule under which the customer is served will be used.

l. Base Usage for each bill is the current Base Load Factor times the number of days in billing period.

m. Heating Usage for each bill is the difference between the actual delivered therms for that bill less the Base Usage for that bill. If the calculated Heating Usage is less than zero, then the Heating Usage for that bill is set equal to zero.

n. Heating Degree Days (HDD) for each day is sixty-five (65) minus the average temperature in degrees Fahrenheit for that day. If the calculated HDD is less than zero, then the HDD for that day is set equal to zero.

o. Normal Heating Degree Days (Normal HDD) for each day is the thirty-year average HDD for that day.

p. Normal Weather Adjustment Slope (NWA Slope) for each bill is the Heating Usage divided by the sum of actual HDD during the billing period.

q. Normal Heating Usage for each bill is the NWA Slope times the sum of the Normal HDD for the billing period.

r. Normal Usage for each bill is the sum of the Base Usage and the Normal Heating Usage.

s. Normal Weather Factor (NWF) for each bill is

$$\text{NWF} = \frac{\text{DeliveryCharge}_{\text{Normal}}}{\text{DeliveryCharge}_{\text{Actual}}} - 1$$

where Delivery Charge Normal is the calculated delivery charge for Normal Usage for the rate schedule applicable to that bill or portion thereof during the Winter Period and Delivery Charge Actual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Decoupling Year, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next Billing Year, effective November 1.

The Revenue Decoupling Adjustment shall be determined by calculating the monthly difference between the Benchmark Base Revenue per Customer times the actual number of Equivalent Bills for the applicable Customer Class and the Actual Base Revenue for that month. The sum of these monthly Revenue Decoupling Adjustments in the Decoupling Year shall be divided by forecasted Billing Year sales to derive the volumetric rate per therm to be applied to customers' bills in the Billing Year. The Revenue Decoupling Adjustment shall also include a reconciliation component for the previous Decoupling Year, which represents the difference between the accrued decoupling amount in the Decoupling Year compared to the actual revenues billed in the billing Year.

b. Revenue Decoupling Adjustment Formulas

$$\text{RD}_{\text{CG}} = \sum_{\text{RC}=1}^{\text{RC}=\text{n}} \left[\left(\text{BRPC}_{\text{T}-1} \text{ x ACUSTS}_{\text{T}-1}\right) - \text{AR}_{\text{T}-1}\right)\right]$$

And:

$$\text{RDAF}_{\text{CG}} = \frac{\text{RD}_{\text{CG}} + \text{CGDEF}_{\text{T}-1}}{\text{FTV}_{\text{CG}}}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}$ The Actual Number of Equivalent Bills for the applicable Customer Class for the most recently completed Decoupling Year (T-1)

$\mathrm{AR}_{\mathrm{T-1}}$ The Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year, (T-1), as defined in Section 4(D). For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.

$\mathrm{BRPC}_{\mathrm{T-1}}$ The Benchmark Base Revenue Per Equivalent Bill for the applicable Customer Class as determined in accordance with Section 4 (D) for the most recently completed Decoupling Year, stated on a monthly basis (T-1).

cg Customer Class Groups as defined in Section 4(D).

$CG\mathrm{DEF}$ The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.

$\mathrm{FTV}_{\mathrm{CG}}$ Forecast Throughput Volumes inclusive of all firm tariff throughput for the Billing Year.

rc Rate Classes in a Customer Group.

$\mathrm{RD}_{\mathrm{CG}}$ The Revenue Decoupling adjustment to revenues, representing the sum of the monthly Revenue Decoupling Adjustments in the Decoupling Year.

$\mathrm{RDAF}_{\mathrm{cg}}$ The Revenue Decoupling Adjustment Factor for the Billing Year.

6. Calculation of the RDAC Reconciliation Adjustments

Account 1168-1823 shall contain the accumulated difference between annual revenues and the Revenue Decoupling Adjustment, as calculated by multiplying the RDAF times firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues annually, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

The RDAF ($ per therm) shall be calculated annually for each Customer Group and shall be truncated at the nearest one one-hundredth of a cent per therm. The annual calculated Customer Group RDAF will be applied to the monthly firm tariff throughput for each customer in that particular Customer Group, effective November 1 of the given year.

8. Calculation of Normal Weather Adjustment

The Normal Weather Adjustment (NWA) for each bill is

$$\mathrm{NWA} = \mathrm{DeliveryCharge}_{\mathrm{Actual}} \times \mathrm{NWF}$$

where Delivery Charge Actual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

9. Application of the NWA to Customer Bills

The NWA charge or credit will be separately stated, and added to or subtracted from each bill as applicable. Each bill will have a separate line titled "Normal Weather Adj.," which line will include the total variable distribution charges, the NWF percentage, and the resulting charge or credit.

10. Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the LDAC. Such information shall include:

a. The calculation of the applicable revenue decoupling revenue dollar adjustment for the Decoupling Year by Customer Class Group.

b. The calculation of the revenue decoupling reconciliation dollar adjustment for the previous Decoupling Year by Customer Class Group.

c. The calculation of the proposed decoupling rate per therm for each customer class group to be applied in the Billing Year.

d. The calculation of the monthly Benchmark Base Revenue per Customer, to be utilized in the upcoming Decoupling Year. If distribution rates change during the Decoupling Year, the monthly Benchmark Base Revenue per Customer for the remaining months of the Decoupling Year will be revised and filed with the Commission.

E. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation (“RCE”) shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A{:}\ TPev}$$

where:

A: Tpev	Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.
RLIAP	RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.
RA_{RLIAP}	RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{X} = CC^{X} + RDAF^{X} + ES + GREF^{x} + RCE + RLIAP$$

and:

$ES^X = RHS + MGP$

where:

$LDAC^X$ = Annualized class specific LDAC.

CC^X = Annualized class specific CC or EE Charge.

$RDAF^X$ = Annualized class specific RDAF.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^X$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

K. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

L. Amendments to Uniform System of Accounts.

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(E).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 17(G).

1163-1756 **Revenue Decoupling Adjustment Factor:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(D).

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

B. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

C. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

D. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

E. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

F. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

G. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

H. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not

I. RATE SCHEDULES

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1

Availability

This rate is available to all residential customers who do not have gas space heating equipment, who consume less than 80% of their normal usage in the six winter months of November through April and whose usage does not exceed 100 therms in any winter month. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.5007 per day or $15.02 per 30 day month
Winter Period:	All therms per 30 day month at $0.3741 per therm
Summer Period:	All therms per 30 day month at $0.3741 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days’ notice before discontinuance of service and is responsible for all charges through the end of the notice period.

2 RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-3

Availability
This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.5007 per day or $15.02 per 30 day month
Winter Period:	All therms per 30 day month at $0.5502 per therm
Summer Period:	All therms per 30 day month at $0.5502 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

3 LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4

Availability
This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.2003 per day or $6.01 per 30 day month
Winter Period:	All therms per 30 day month at $0.2201 per therm
Summer Period:	All therms per 30 day month at $0.2201 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery

4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Residential Non Heating Rate R-1.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.6510 per day or $19.53 per 30 day month
Winter Period:	All therms per 30 day month at $0.4863 per therm
Summer Period:	All therms per 30 day month at $0.4863 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program projects area who otherwise would have qualified for Residential Heating Rate R-3.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.6510 per day or $19.53 per 30 day month
Winter Period:	All therms per 30 day month at $0.7153 per therm
Summer Period:	All therms per 30 day month at $0.7153 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-3.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

6 MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Low Income Residential Heating Rate R-4.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.2603 per day or $7.81 per 30 day month
Winter Period:	All therms per 30 day month at $0.2861 per therm
Summer Period:	All therms per 30 day month at $0.2861 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00

7 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE
CLASSIFCATION NO. G-41

Availability

This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company’s records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8560 per day or $55.68 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.4566 per therm
	All over 100 therms per 30 day month at $0.3067 per therm
Summer Period:	First 20* therms per 30 day month at $0.4566 per therm
	All over 20 therms per 30 day month at $0.3067 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-42

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$5.5687 per day or $167.06 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.4152 per therm
	All over 1000 therms per 30 day month at $0.2766 per therm
Summer Period:	First 400* therms per 30 day month at $0.4152 per therm
	All over 400 therms per 30 day month at $0.2766 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$23.8983 per day or $716.95 per 30 day month
Winter Period:	All therms per 30 day month at $0.2552 per therm
Summer Period:	All therms per 30 day month at $0.1167 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the N Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44

Availability

This rate is Mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-41.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4130 per day or $72.38 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5936 per therm
	All over 100 therms per 30 day month at $0.3987 per therm
Summer Period:	First 20* therms per 30 day month at $0.5936 per therm
	All over 20 therms per 30 day month at $0.3987 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first

11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-42.

Character of Service

Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$7.2393 per day or $217.18 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.5398 per therm
	All over 1000 therms per 30 day month at $0.3596 per therm
Summer Period:	First 400* therms per 30 day month at $0.5398 per therm
	All over 400 therms per 30 day month at $0.3596 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-43.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$31.0680 per day or $932.04 per 30 day month
Winter Period:	All therms per 30 day month at $0.3318 per therm
Summer Period:	All therms per 30 day month at $0.1517 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE
CLASSIFICATION NO. G-51

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8560 per day or $55.68 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2752 per therm
	All over 100 therms per 30 day month at $0.1789 per therm
Summer Period:	First 100* therms per 30 day month at $0.2752 per therm
	All over 100 therms per 30 day month at $0.1789 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this

14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE
CLASSIFICATION NO. G-52

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company’s records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer’s consumption fail to meet the availability requirements for this rate, the customer’s service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$5.5687 per day or $167.06 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.2363 per therm
	All over 1000 therms per 30 day month at $0.1574 per therm
Summer Period:	First 1000* therms per 30 day month at $0.1712 per therm
	All over 1000 therms per 30 day month at $0.0973 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE
CLASSIFICATION NO. G-53

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$24.5947 per day or $737.84 per 30 day month
Winter Period:	All therms per 30 day month at $0.1652 per therm
Summer Period:	All therms per 30 day month at $0.0792 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-54

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$24.5947 per day or $737.84 per 30 day month
Winter Period:	All therms per 30 day month at $0.0630 per therm
Summer Period:	All therms per 30 day month at $0.0342 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

**17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE
CLASSIFICATION NO. G-55**

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-51.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4130 per day or $72.38 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.3578 per therm
	All over 100 therms per 30 day month at $0.2326 per therm
Summer Period:	First 100* therms per 30 day month at $0.3578 per therm
	All over 100 therms per 30 day month at $0.2326 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions
Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-56

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-52.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$7.2393 per day or $217.18 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.3072 per therm
	All over 1000 therms per 30 day month at $0.2046 per therm
Summer Period:	First 1000* therms per 30 day month at $0.2226 per therm
	All over 1000 therms per 30 day month at $0.1265 per therm

*****The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In

19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFCATION NO. G-57

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-53.

Character of Service

Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$31.9730 per day or $959.19 per 30 day month
Winter Period:	All therms per 30 day month at $0.2148 per therm
Summer Period:	All therms per 30 day month at $0.1030 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer

20 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-58

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-54.

Character of Service

Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$31.9730 per day or $959.19 per 30 day month
Winter Period:	All therms per 30 day month at $0.0819 per therm
Summer Period:	All therms per 30 day month at $0.0445 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-54.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

21 OUTDOOR GAS LIGHTING

Availability
This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services. Service under this rate is available at those locations which were receiving service hereunder as of July 1, 2015, and which have continuously received service hereunder since that date.

Rate Per Light Per Month	$12.81

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

22 FIRM RATE SCHEDULES EXCLUDING KEENE CUSTOMERS

	Rates effective November 1, 2018 - April 30, 2019 Winter Period				Rates Effective May 1, 2019 - October 31, 2019 Summer Period			
	Delivery Charge	**Cost of Gas Rate Page 92**	**LDAC Page 97**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 15.02			$15.02	$ 15.02			$ 15.02
All therms	$0.3741	$0.7411	$0.0660	$1.1812	$ 0.3741	$0.4445	$0.0660	$ 0.8846
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 15.02			$15.02	$ 15.02			$ 15.02
All therms	$0.5502	$0.7411	$0.0660	$ 1.3573	$ 0.5502	$0.4445	$0.0660	$ 1.0607
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 6.01			$6.01	$ 6.01			$ 6.0065
All therms	$0.2201	$0.7411	$0.0660	$ 1.0272	$0.2201	$0.4445	$0.0660	$ 0.7306
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$ 55.68			$55.68	$ 55.68			$ 55.68
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$0.4566	$ 0.7403	$ 0.0757	$ 1.2726	$ 0.4566	$ 0.4417	$ 0.0757	$ 0.9740
All therms over the first block per month at	$0.3067	$ 0.7403	$ 0.0757	$ 1.1227	$ 0.3067	$ 0.4417	$ 0.0757	$ 0.8241
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$ 167.06			$167.06	$ 167.06			$ 167.06
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$0.4152	$ 0.7403	$ 0.0757	$ 1.2312	$ 0.4152	$ 0.4417	$ 0.0757	$ 0.9326
All therms over the first block per month at	$0.2766	$ 0.7403	$ 0.0757	$ 1.0926	$ 0.2766	$ 0.4417	$ 0.0757	$ 0.7940
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$ 716.95			$716.95	$ 716.95			$ 716.95
All therms over the first block per month at	$0.2552	$ 0.7403	$ 0.0757	$1.0712	$ 0.1167	$ 0.4417	$ 0.0757	$ 0.6341
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$ 55.68			$55.68	$ 55.68			$ 55.68
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$0.2752	$ 0.7456	$ 0.0757	$ 1.0965	$ 0.2752	$ 0.4506	$ 0.0757	$ 0.8015
All therms over the first block per month at	$0.1789	$ 0.7456	$ 0.0757	$ 1.0002	$ 0.1789	$ 0.4506	$ 0.0757	$ 0.7052
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$ 167.06			$167.06	$ 167.06			$ 167.06
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$0.2363	$ 0.7456	$ 0.0757	$ 1.0576	$ 0.1712	$ 0.4506	$ 0.0757	$ 0.6975
All therms over the first block per month at	$0.1574	$ 0.7456	$ 0.0757	$ 0.9787	$ 0.0973	$ 0.4506	$ 0.0757	$ 0.6236
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$ 737.84			$737.84	$ 737.84			$ 737.84
All therms over the first block per month at	$0.1652	$ 0.7456	$ 0.0757	$0.9865	$ 0.0792	$ 0.4506	$ 0.0757	$ 0.6055
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$ 737.84			$737.84	$ 737.84			$ 737.84
All therms over the first block per month at	$0.0630	$ 0.7456	$ 0.0757	$0.8843	$ 0.0342	$ 0.4506	$ 0.0757	$ 0.5605

23 FIRM RATE SCHEDULES KEENE CUSTOMERS

	Rates effective November 1, 2018 - April 30, 2019 Winter Period				Rates Effective October 1, 2018 - October 31, 2018 Summer Period [1]			
	Delivery Charge	Cost of Gas Rate Page 92	LDAC Page 97	Total Rate	Delivery Charge	Cost of Gas Rate Page 90	LDAC Page 97	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 15.02			$15.02	$ 15.02			$ 15.02
All therms	$0.3741	$1.3802	$0.0660	$1.8203	$ 0.3938	$1.2494	$0.0945	$ 1.7377
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 15.02			$15.02	$ 15.02			$ 15.02
All therms	$0.5502	$1.3802	$0.0660	$ 1.9964	$ 0.5631	$1.2494	$0.0945	$ 1.9070
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 6.01			$6.01	$ 6.00			$ 6.0000
All therms	$0.2201	$1.3802	$0.0660	$ 1.6663	$0.2252	$1.2494	$0.0945	$ 1.5691
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$ 55.68			$55.68	$ 56.58			$ 56.58
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$0.4566	$1.3802	$ 0.0757	$ 1.9125	$ 0.4639	$1.2494	$ 0.0763	$ 1.7896
All therms over the first block per month at	$0.3067	$1.3802	$ 0.0757	$ 1.7626	$ 0.3116	$1.2494	$ 0.0763	$ 1.6373
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$ 167.06			$167.06	$ 169.75			$ 169.75
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$0.4152	$1.3802	$ 0.0757	$ 1.8711	$ 0.4219	$1.2494	$ 0.0763	$ 1.7476
All therms over the first block per month at	$0.2766	$1.3802	$ 0.0757	$ 1.7325	$ 0.2811	$1.2494	$ 0.0763	$ 1.6068
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$ 716.95			$716.95	$ 728.47			$ 728.47
All therms over the first block per month at	$0.2552	$1.3802	$ 0.0757	$1.7111	$ 0.1185	$1.2494	$ 0.0763	$ 1.4442
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$ 55.68			$55.68	$ 56.58			$ 56.58
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$0.2752	$1.3802	$ 0.0757	$ 1.7311	$ 0.2796	$1.2494	$ 0.0763	$ 1.6053
All therms over the first block per month at	$0.1789	$1.3802	$ 0.0757	$ 1.6348	$ 0.1817	$1.2494	$ 0.0763	$ 1.5074
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$ 167.06			$167.06	$ 169.75			$ 169.75
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$0.2363	$1.3802	$ 0.0757	$ 1.6922	$ 0.1740	$1.2494	$ 0.0763	$ 1.4997
All therms over the first block per month at	$0.1574	$1.3802	$ 0.0757	$ 1.6133	$ 0.0989	$1.2494	$ 0.0763	$ 1.4246
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$ 737.84			$737.84	$ 749.68			$ 749.68
All therms over the first block per month at	$0.1652	$1.3802	$ 0.0757	$1.6211	$ 0.0805	$1.2494	$ 0.0763	$ 1.4062
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$ 737.84			$737.84	$ 749.68			$ 749.68
All therms over the first block per month at	$0.0630	$1.3802	$ 0.0757	$1.5189	$ 0.0347	$1.2494	$ 0.0763	$ 1.3604

[1] For Keene rates in effect prior to May 1, 2018 please see tariff:
NHPUC NO. 1 - GAS LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP D/B/A
LIBERTY UTILITIES - KEENE DIVISION

ISSUED: November 14, 2018

EFFECTIVE: November 01, 2018

ISSUED BY: /s/Susan L. Fleck
Susan L. Fleck

TITLE: President

Authorized by NHPUC Order No. 26,184 dated October 30, 2018 in Docket No. DG 18-145 and Order No. 26,188 dated November 01, 2018 in Docket No. 18-137 and Order No. 26,187 dated November 02, 2018 in Docket No. 17-048

24 FIRM RATE SCHEDULES EXCLUDING KEENE CUSTOMERS – MANAGED EXPANSION PROGRAM

	Rates effective November 1, 2018 - April 30, 2019 Winter Period				Rates Effective May 1, 2019 - October 31, 2019 Summer Period			
	Delivery Charge	**Cost of Gas Rate Page 92**	**LDAC Page 97**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**
Residential Non Heating - R-5								
Customer Charge per Month per Meter	$ 19.53			$19.53	$ 19.53			$ 19.53
All therms	$0.4863	$0.7411	$0.0660	$1.2934	$ 0.4863	$0.4445	$0.0660	$ 0.9968
Residential Heating - R-6								
Customer Charge per Month per Meter	$ 19.53			$19.53	$ 19.53			$ 19.53
All therms	$0.7153	$0.7411	$0.0660	$ 1.5224	$ 0.7153	$0.4445	$0.0660	$ 1.2258
Residential Heating - R-7								
Customer Charge per Month per Meter	$ 7.81			$7.81	$ 7.81			$ 7.81
All therms	$0.2861	$0.7411	$0.0660	$ 1.0932	$0.2861	$0.4445	$0.0660	$ 0.7966
Commercial/Industrial - G-44								
Customer Charge per Month per Meter	$ 72.38			$72.38	$ 72.38			$ 72.38
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$0.5936	$ 0.7403	$ 0.0757	$ 1.4096	$ 0.5936	$ 0.4417	$ 0.0757	$ 1.1110
All therms over the first block per month at	$0.3987	$ 0.7403	$ 0.0757	$ 1.2147	$ 0.3987	$ 0.4417	$ 0.0757	$ 0.9161
Commercial/Industrial - G-45								
Customer Charge per Month per Meter	$ 217.18			$217.18	$ 217.18			$ 217.18
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$0.5398	$ 0.7403	$ 0.0757	$ 1.3558	$ 0.5398	$ 0.4417	$ 0.0757	$ 1.0572
All therms over the first block per month at	$0.3596	$ 0.7403	$ 0.0757	$ 1.1756	$ 0.3596	$ 0.4417	$ 0.0757	$ 0.8770
Commercial/Industrial - G-46								
Customer Charge per Month per Meter	$ 932.04			$932.04	$ 932.04			$ 932.04
All therms over the first block per month at	$0.3318	$ 0.7403	$ 0.0757	$1.1478	$ 0.1517	$ 0.4417	$ 0.0757	$ 0.6691
Commercial/Industrial - G-55								
Customer Charge per Month per Meter	$ 72.38			$72.38	$ 72.38			$ 72.38
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$0.3578	$ 0.7456	$ 0.0757	$ 1.1791	$ 0.3578	$ 0.4506	$ 0.0757	$ 0.8841
All therms over the first block per month at	$0.2326	$ 0.7456	$ 0.0757	$ 1.0539	$ 0.2326	$ 0.4506	$ 0.0757	$ 0.7589
Commercial/Industrial - G-56								
Customer Charge per Month per Meter	$ 217.18			$217.18	$ 217.18			$ 217.18
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$0.3072	$ 0.7456	$ 0.0757	$ 1.1285	$ 0.2226	$ 0.4506	$ 0.0757	$ 0.7489
All therms over the first block per month at	$0.2046	$ 0.7456	$ 0.0757	$ 1.0259	$ 0.1265	$ 0.4506	$ 0.0757	$ 0.6528
Commercial/Industrial - G-57								
Customer Charge per Month per Meter	$ 959.19			$959.19	$ 959.19			$ 959.19
All therms over the first block per month at	$0.2148	$ 0.7456	$ 0.0757	$1.0361	$ 0.1030	$ 0.4506	$ 0.0757	$ 0.6293
Commercial/Industrial - G-58								
Customer Charge per Month per Meter	$ 959.19			$959.19	$ 959.19			$ 959.19
All therms over the first block per month at	$0.0819	$ 0.7456	$ 0.0757	$0.9032	$ 0.0445	$ 0.4506	$ 0.0757	$ 0.5708

25 FIRM RATE SCHEDULES – OUTDOOR GAS LIGHTING

Outdoor Gas Lighting	
Per Light Per Month	$12.81

33. ENVIRONMENTAL SURCHARGE

Manufactured Gas Plants

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

34 RATE CASE EXPENSE AND RECOUPMENT FACTOR CALCULATION

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

1	Rate Case Expense Remaining from Docket No. DG 14-180	$51,485
2	Rate Case Expense Through June 2018 in Docket No. DG 17-048	$578,477
3	Rate Case Expense for Docket No. DG 17-048 Currently Approved for $530,000	($48,477)
4	Remaining Recoupment from DG 14-180 & DG 17-048	$1,633,854
5	July 1, 2018 Balance	$2,215,339
6	Minus November 2019 & December 2019 Recoupment	($233,408)
7	Minus DG 17-048 Rate Case Rehearing Adjustments	($240,126)
8	Minus Estimated Recoveries from July 2018 through October 2018	($312,077)
9	Total Estimated Remaining Recovery As Of November 1, 2018	$1,429,728
10	Estimated November 2018 - October 2019 Interest	$36,303
11	Total Remaining Recovery	$1,466,032
12	Estimated November 2018 - October 2019 Sales (therms)	184,654,874
13	RCE & Recoupment rate per therm November 2018 - October 2019	$0.0079

35 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION

NHPUC NO. 10 - GAS — **Proposed First Revised Page 97**
LIBERTY UTILITIES — ***Superseding Original Page 97***

Local Delivery Adjustment Clause Calculation

Residential Non Heating Rates - R-1, R-5		**Sales Customers**	**Transportation Customers**	
Energy Efficiency Charge	$0.0287			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0287		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0161			
Environmental Surcharge (ES)		0.0161		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0003		
Rate Case Expense Factor (RCEF)		0.0079		
Residential Low Income Assistance Program (RLIAP)		0.0130		
LDAC		**$0.0660**		**per therm**

Residential Heating Rates - R-3, R-4, R-6, R-7				
Energy Efficiency Charge	$0.0287			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0287		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0161			
Environmental Surcharge (ES)		0.0161		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0003		
Rate Case Expense Factor (RCEF)		0.0079		
Residential Low Income Assistance Program (RLIAP)		0.0130		
LDAC		**$0.0660**		**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55				
Energy Efficiency Charge	$0.0387			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0387	$0.0387	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0161			
Environmental Surcharge (ES)		0.0161	0.0161	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0001	0.0001	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0079	0.0079	
Residential Low Income Assistance Program (RLIAP)		0.0128	0.0128	
LDAC		**$0.0757**	**$0.0757**	**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56				
Energy Efficiency Charge	$0.0387			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0387	$0.0387	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0161			
Environmental Surcharge (ES)		0.0161	0.0161	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0001	0.0001	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0079	0.0079	
Residential Low Income Assistance Program (RLIAP)		0.0128	0.0128	
LDAC		**$0.0757**	**$0.0757**	**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57,G-58				
Energy Efficiency Charge	$0.0387			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0387	$0.0387	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0161			
Environmental Surcharge (ES)		0.0161	0.0161	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0001	0.0001	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0079	0.0079	
Residential Low Income Assistance Program (RLIAP)		0.0128	0.0128	
LDAC		**$0.0757**	**$0.0757**	**per therm**

ISSUED: November 16, 2018 — ISSUED BY: /s/Susan L. Fleck
Susan L. Fleck
EFFECTIVE: November 01, 2018 — TITLE: President

Authorized by NHPUC Order No. 26,187 dated November 2, 2018, in Docket No. DG 17-048

REDACTED

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 18-XXX

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

DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

August 31, 2018

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I. INTRODUCTION

Q. Please state your full name and business address.

A. (DS) My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire

(CM) My name is Catherine A. McNamara. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("Liberty"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

Q. Please describe your educational background and your business and professional experience.

A. (DS) I graduated from Ferris State University in 1993 with a Bachelor of Science in Finance. I received a Master's of Science in Finance from Walsh College in 2000. I also received a Master's of Business Administration from Walsh College in 2001. In 2006, I earned a Graduate Certificate in Power Systems Management from Worcester Polytechnic Institute. In August 2013, I joined Liberty as a Utility Analyst and I was promoted to Manager, Rates and Regulatory Affairs in August 2017. Prior to my employment at Liberty, I was employed by NSTAR Electric & Gas ("NSTAR") as a Senior Analyst in Energy Supply from 2008 to 2012. Prior to my position in Energy

Supply at NSTAR, I was a Senior Financial Analyst within the NSTAR Investment Planning group from 2004 to 2008.

(CM) I graduated from the University of Massachusetts, Boston, in 1993 with a Bachelor of Science in Management with a concentration in Accounting. In November 2017, I joined Liberty as an Analyst in Rates and Regulatory Affairs. Prior to my employment at Liberty, I was employed by Eversource as a Senior Analyst in the Investment Planning group from 2015 to 2017. From 2008 to 2015, I was a Supervisor in the Plant Accounting department. Prior to my position in Plant Accounting, I was a Financial Analyst/General Ledger System Administrator within the Accounting group from 2000 to 2008.

Q. Have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. (DS) Yes. I have testified on numerous occasions before the Commission.

(CM) Yes, I previously testified in EnergyNorth's Cast Iron/Bare Steel Replacement Program proceeding, Docket No. DG 18-064.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's proposed firm sales cost of gas rates for the 2018/19 Winter (Peak) Period and the Company's proposed 2018/19 Local Delivery Adjustment Clause, both effective November 1, 2018. Our testimony also explains the Company's proposed firm sales cost of gas rates for the 2019 Summer (Off-Peak) Period.

II. WINTER 2018/19 COST OF GAS FACTOR

Q. What are the proposed firm Winter sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.7411 per therm for residential customers, $0.7403 per therm for commercial/industrial high winter use customers, and $0.7456 per therm for commercial/industrial low winter use customers as shown on Proposed First Revised Page 92 (Bates 050). The Company proposes a firm transportation cost of gas rate of $0.0005 per therm as shown on Proposed First Revised Page 94 (Bates 052).

Q. Please explain tariff page Proposed Original Page 92.1 (Bates 051) and Proposed First Revised Page 92.

A. Proposed Original Page 92.1 and Proposed First Revised Page 92 contain the calculation of the 2018/19 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 92, the proposed 2018/19 Average Cost of Gas of $0.7411 per therm is derived by adding the Direct Cost of Gas Rate of $0.7056 per therm to the Indirect Cost of Gas Rate of $0.0355 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Page 92.1 and repeated on Page 92, is $61,003,856. The estimated Indirect Cost of Gas, also derived on Page 92.1 and repeated on Page 92, is $3,070,244. The Direct Cost of Gas Rate of $0.7056 and the Indirect Cost of Gas Rate of $0.0355 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 86,451,254 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 92.1, total $656,690. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $60,347,166 to determine the Total Anticipated Direct Cost of Gas of $61,003,856.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Original Page 92.1 consists of the following components:

1.	Purchased Gas Demand Costs	$10,308,483
2.	Purchased Gas Commodity Costs	41,318,346
3.	Storage Demand and Capacity Costs	922,462
4.	Storage Commodity Costs	5,125,663
5.	Produced Gas Cost	2,672,211
	Total	$60,347,166*

*$1 difference due to rounding

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Original Page 92.1, are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$2,599,354
2.	Interest	63,196

3.	Fuel Inventory Revenue Requirement	351,017
4.	Broker Revenues	(497,759)
5.	Transportation COG Revenue	(26,381)
6.	Capacity Release Margin	(1,877,737)
7.	Fixed Price Administrative Cost	45,000
	Total Adjustments	$656,690

These allowable adjustments are standard adjustments made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. We discuss the factors contributing to the prior period under collection later in this testimony.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in Docket No. DG 17-135 for the 2017/18 Winter Period?

A. The average cost of gas rate proposed in this filing of $0.7411 per therm is $0.0966 per therm more than the initial rate of $0.6445[1] per therm approved by the Commission in Order No. 26,066 (October 31, 2017) in Docket No. DG 17-135. The $0.0966 per therm increase in the rate reflects a $2,530,984 increase in the Total Unadjusted Cost of Gas.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2017/18 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0005 per therm. The rate approved in Docket No. DG 17-135 was $0.0027 per therm. The decrease in the rate relates to an estimated $88,304 decrease in costs due to the difference between the winter

1 For comparison purposes, by the end of the 2017/18 Winter Period, the residential cost of gas rate increased to $0.8056 per therm through the operation of the monthly adjustment mechanism.

season 2017/2018 beginning balance of $28,808 (an over-collection) and the winter season 2018/2019 beginning balance of ($59,496) (an under-collection).

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. Yes. The Company used, for pressure support purposes, a rate of 8.7% based on the marginal cost study used for the rate design approved in Docket No. DG 17-048. Previously the Company used an estimated percentage of 9.9% for pressure support purposes.

Q. Did the Company include a fuel inventory revenue requirement calculation in this filing?

A. Yes (Bates 192). The Company is proposing to collect $351,017 in fuel inventory revenue requirement consistent with Order No. 26,156 dated July 10, 2018, in Docket No. DG 17-048. The rate of $0.0041 per therm is determined by dividing the $351,017 by the estimated November 2018 through October 2019 COG sales volumes of 86,451,254 therms.

Q. How was the statutory tax rate of 27.24% calculated (Bates 192)?

A. The statutory rate of 27.24% was calculated by using a 21% federal tax rate and a 7.9% tax rate for the State of New Hampshire (0.21 + 0.079 – (0.21 x 0.079) = 0.2724).

Q. How was the common equity pre-tax rate of 6.290% calculated (Bates 192)?

A. The common equity pre-tax rate of 6.290% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 17-048, by 0.7276 (1 – 0.2724 [statutory tax rate – see previous question]) and multiplied by 49.20% (equity component of the capital structure approved in DG 17-048) [0.930 / 0.7276 x 0.4920 = 0.0629].

Q. Has the bad debt percentage in this filing of 1.7% changed from the bad debt percentage calculated in the Winter 2017/2018 Cost of Gas Reconciliation?

A. Yes, the bad debt percentage of 1.7% used in this filing is the calculated rate for the period of May 2017–April 2018. The Winter 2017/2018 Cost of Gas Reconciliation included a calculated rate of 1.1%, which was inadvertently carried forward from the prior period of May 2016–April 2017.

Q. What was the actual weighted average firm sales cost of gas rate for the 2017/18 winter period?

A. The weighted average cost of gas rate was $0.7321 per therm (Bates 095 Line 54). This was calculated by applying the actual monthly cost of gas rates for November 2017 through April 2018 to the monthly therm usage of an average residential heating customer using 778 therms per year, or 636 therms for the six winter period months.

III. <u>PRIOR WINTER PERIOD UNDER-COLLECTION</u>

Q. Please explain the prior period under collection of $2,459,330.

A. The prior period under-collection is also detailed in the 2017/18 Winter Period Reconciliation that was filed with the Commission on July 27, 2018. The $2,459,330 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2018. The under-collection was driven mainly by the lag in the timing of monthly cost of gas rate adjustments as compared to changes in the underlying costs. For three months within the six-month winter period the calculated COG rate adjustment was higher than the allowable 25% price increase so the Company held the rate constant at the maximum allowable rate of $0.8056 per therm.

IV. <u>FIXED PRICE OPTION</u>

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?

A. Yes. Pursuant to Order No. 24,515 in Docket No. DG 05-127, the Fixed Price Option Program ("FPO") rates are set at $0.0200 per therm higher than the initial proposed COG rate. Proposed First Revised Page 91 (Bates 049) contains the FPO rate for the 2018/19 Winter period, which is $0.7611 per therm for residential customers. This compares to the FPO rate approved for the 2017/18 winter period of $0.6645 per therm for residential customers. This represents a $0.0966 per therm, or 14.5% increase in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 636 therms is an increase of approximately $122.86 or 14.25% compared to last winter. The total bill impact reflects the implementation of the increases approved in Docket Nos. DG 17-048 effective May 1, 2018, and DG 18-064 effective July 1, 2018, relating to permanent distribution rates and the cast iron/bare steel main replacement program, respectively. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $12.71 (or 1.3%) higher than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 (Bates 189) contains the historical results of the FPO program.

V. LOCAL DELIVERY ADJUSTMENT CLAUSE ("LDAC")

Q. What are the surcharges that will be billed under the LDAC?

A. As shown on Proposed First Revised Page 97 (Bates 055), the Company is submitting for approval an LDAC of $0.0836 per therm for the residential non-heating class and residential heating class, and $0.0772 per therm for the commercial/industrial bundled sales classes, effective November 1, 2018. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Clause, the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Low Income Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 17-048.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2018, through October 31, 2019, forecasted Keene therm sales of 1,451,361 are added to the EnergyNorth therm sales forecast of 183,203,513 for a total therm sales forecast of 184,654,874.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2019 that will be filed with the Commission in the near future. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period over-recovery of the Company's residential and commercial energy efficiency programs as of October 2018. As shown on Schedule 19 Energy Efficiency (Bates 125-127), the proposed Energy Efficiency charge is $0.0450 per therm for Residential customers and $0.0387 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Clause ("RDAC").

A. The first RDAC will not take effect until November 1, 2019, after the first decoupling year is complete. It is designed to recover, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. The Actual Base Revenue per Customer is calculated after the first decoupling year. Schedule 19 RDAC (Bates 122) shows the proposed Benchmark Base Revenue per Customer calculation effective November 1, 2018, through October 31, 2019.

Q. Please explain the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism ("LRAM").

A. As shown on Schedule 19 LRAM (Bates 120-121), the proposed LRAM charge is $0.0003 per therm for residential customers and $0.0001 per therm for commercial and industrial customers. It is designed to recover lost revenues associated with energy efficiency measures installed under the EERS programs. Since the Company is implementing decoupling effective November 1, 2018, the Company will continue to implement its Lost Revenue Adjustment only as a prior period true-up mechanism effective November 1, 2018, and ending October 31, 2019.

Q. What is the proposed Residential Low Income Assistance Program ("RLIAP") charge?

A. As shown on Schedule 19 RLIAP (Bates 123-124), the proposed RLIAP charge is $0.0130 per therm. It is designed to recover administrative costs, revenue shortfall, and the prior period reconciliation adjustment relating to this program. For the 2018/19 Winter Period, the Company is providing a 60% base rate discount, consistent with the settlement agreement approved by the Commission in Order No. 24,669 (Sept. 22, 2006) in Docket No. DG 06-120. The current RLIAP charge is designed to recover $2,409,164, of which $1,864,087 is for the revenue shortfall resulting from 5,056 customers receiving a 60% discount off their base rates, and $545,077 for the prior year reconciling adjustment.

Q. In Order No. 24,824 (Feb. 29, 2008) in Docket No. DG 06-122 relating to short-term debt issues, the Company agreed to adjust its short-term debt limits each year as part of the Company's Winter Period Cost of Gas filing. Did the Company

calculate the short-term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Schedule 24 (Bates 190) the short-term debt limit for fuel and non-fuel purposes for the 2018/19 period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2018, through October 31, 2019, is calculated to be $19,222,230 and the limit for non-fuel purposes is calculated to be $94,878,262.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 95)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism, as well as the third party recoveries, are included in the Environmental Cost Summary in Schedule 20 (Bates 128) of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Casey in her pre-filed direct testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Schedule 20. The Summary included in Schedule 20 shows the remediation cost pools for the Concord Pond, Concord MGP, Manchester, Nashua, and Laconia sites, and a General Pool for costs that cannot be directly assigned to a specific site.

A summary sheet and detailed backup spreadsheets that support the 2017/18 costs are provided in Schedule 20 of this filing. Consistent with past practice, the Company met with the Commission Staff and OCA in August of this year to provide an update on the status of environmental matters. Ms. Casey's testimony describes the Company's activities with regard to all five sites.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2018, and ending October 31, 2019, is $0.0161 per therm. This surcharge will recover a total of $2,970,867 in amortized remediation costs. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing.

Q. Did the Company include a Rate Case Expense (RCE) surcharge in this filing?

A. Yes. As shown on Schedule 19 RCE (Bates 118-119), the Company is proposing to collect $1,706,158 in uncollected rate case and recoupment expense consistent with Order No. 26,122 dated April 27, 2018, in Docket No. DG 17-048. The RCE rate of $0.0092 per therm is determined by dividing the $1,706,154 by the estimated November 2018 through October 2019 sales volumes of 184,654,874 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2018 through October 2019 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 191) the Company has recalculated its Company Allowance for the period November 2018 through October 2019. The Company calculated the Company Allowance of 1.80% based on sendout and throughput data for the twelve-month period ending June 2018. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2018.

VI. CUSTOMER BILL IMPACTS

Q. What are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's winter bill as compared to the winter rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 (Bates 095) of this filing. These bill impacts reflect the implementation of the increases approved in Docket Nos. DG 17-048 effective May 1, 2018, and DG 18-064 effective July 1, 2018, relating to permanent distribution rate increases and the cast iron/bare steel main replacement program. The total bill impact over the winter period for an average residential heating customer is an increase of approximately $67.17, or 7.42%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is an increase of approximately $86.13, or 3.38% (Bates 096). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed First Revised Page 147 (Bates 056) relating to Supplier Balancing and Peaking Demand Charges and Proposed First Revised Page 148 (Bates 057) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 147.

A. In Proposed First Revised Page 147, the Company is updating the Peaking Demand Charge from $20.06 per MMBtu of Peak MDQ to $20.41 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 180).

Q. Please describe the changes to tariff Page 148.

A. Proposed First Revised Page 148 updates the Capacity Allocator percentages used to allocate pipeline, storage, and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 (Bates 183-188) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2019 COST OF GAS FACTOR

Q. What are the proposed 2019 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.4445 per therm for residential customers, $0.4417 per therm for commercial/industrial high winter use customers, and $0.4506 per therm for commercial/industrial low winter use customers as shown on Proposed Seventh Revised Page 89 (Bates 200).

Q. Please explain tariff pages Proposed First Revised Page 88 and Proposed Seventh Revised Page 89.

A. Proposed First Revised Page 88 (Bates 199) and Proposed Seventh Revised Page 89 contain the calculation of the 2019 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed

Seventh Revised Page 89, the 2019 Average Cost of Gas of $0.4445 per therm is derived by adding the Direct Cost of Gas Rate of $0.4354 per therm to the Indirect Cost of Gas Rate of $0.0091 per therm. The estimated total Anticipated Direct Cost of gas is $8,661,183 and the estimated Indirect Cost of Gas is $181,903. The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected Summer firm sales volumes of 19,890,267 therms. Proposed Seventh Revised Page 89 further shows that the Residential Cost of Gas Rate of $0.4445 per therm is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial High Winter Use Cost of Gas Rate of $0.4417 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.4506 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed First Revised Page 88. To derive the total Anticipated Direct Cost of Gas of $8,661,183, the Company starts with the Unadjusted Anticipated Cost of Gas of $8,002,703 and adds the Net Adjustment totaling $658,480.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1. Purchased Gas Demand Costs	$4,372,669
2. Purchased Gas Supply Costs	3,602,943
3. Produced Gas Costs	27,091
Total Unadjusted Anticipated Cost of Gas	$8,002,703

Q. What are the components of the adjustments to the cost of gas?

A. The adjustments to gas costs, listed on proposed First Revised Page 88, are as follows:

1. Prior Period (Over)/Under Collection	$617,043
2. Interest	41,437
Total Adjustments	$658,480

Q. How does the proposed average Residential Summer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2018 Summer Period?

A. The cost of gas rate proposed in this filing is $0.1312 per therm higher than the initial rate approved by the Commission for the 2018 Summer Period ($0.4445 vs. $0.3133) (Schedule 8, Bates 224). This increase is primarily due to an $874 thousand anticipated increase to the Supply Costs.

Q. Does this conclude your testimony?

A. Yes, it does.

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

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

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

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

REDACTED

Ln											
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
152	**D. Supply and Demand Costs by Source**										**REDACTED**
153											
154	Purchased Gas Demand Costs										
155	Pipeline Gas Demand Costs	lns 55 + 76	$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570		$ 9,738,885
156	Peaking Gas Demand Costs	ln 84	-	993,750	993,750	993,750	993,750	993,750	-		4,968,750
157	Subtotal Purchased Gas Demand Costs		$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570		$ 14,707,635
158	Less Capacity Credit	lns 56 + 77 + 85	(524,979)	(693,594)	(693,594)	(693,594)	(693,594)	(693,594)	(406,202)		(4,399,152)
159	Net Purchased Gas Demand Costs		$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368		$ 10,308,483
160											
161	Storage Gas Demand Costs										
162	Storage Demand	ln 96	$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317		$ 1,407,802
163	Less Capacity Credit	ln 97	(281,772)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)		(485,340)
164	Net Storage Demand Costs		$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389		$ 922,462
165											
166	**Total Demand Costs**	lns 159 + 164	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
167											
168	Purchased Gas Supply										
169	Commodity Costs	ln 118	$ -	$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499		$ 42,563,780
170	Less Storage Inj.(TGP Storage)	ln 131	[redacted]								
171	Less Storage Transportation	ln 132									
172	Less LNG Truck	ln 129									
173	Less Propane Truck	ln 130									
174	Plus Transportation Costs	ln 143									
175	Subtotal Purchased Gas Supply		$ -	$ 2,527,981	$ 8,837,950	$ 11,224,354	$ 10,752,485	$ 5,545,818	$ 2,138,024		$ 41,026,613
176											
177	Storage Commodity Costs										
178	Commodity Costs	ln 121	$ -	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894		$ 5,125,663
179	Transportation Costs	ln 145	-	25,361	60,588	75,479	75,113	54,742	449		291,733
180	Subtotal Storage Commodity Costs		$ -	$ 470,947	$ 1,125,101	$ 1,401,627	$ 1,394,830	$ 1,016,547	$ 8,344		$ 5,417,397
181											
182	Produced Gas Commodity Costs	ln 126	$ -	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567		$ 2,672,211
183											
184	**Subtotal Commodity Costs**	lns 175 + 180 + 182	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
185											
186	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
187											
188	**Total Commodity Costs**	lns 184 + 186	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
189											
190	**Total Demand Costs**	ln 102	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
191	**Total Supply Costs**	ln 188	-	3,013,068	10,121,153	14,458,463	12,777,150	6,591,451	2,154,935		49,116,221
192											
193	**Total Direct Gas Costs**	lns 190 + 191	$ 1,208,615	$ 4,801,183	$ 11,909,268	$ 16,246,578	$ 14,565,265	$ 8,379,566	$ 3,236,692		$ 60,347,167
194											
195							**REDACTED**				

Line	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**					
2						
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**					
4	**Contracts Ranked on a per Unit Cost Basis**					
5						
6						
7	(a)	(b)	(c)	(d)	(e)	(f)
8						
9	**Demand Costs**					
10	ENGIE Demand FLS		Peaking	MDQ	3,000	[redacted]
11	Niagara Supply		Supply	MDQ	3,199	[redacted]
12	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	[redacted]
13	Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	[redacted]
14	National Fuel - Capacity Reservation	FSS-O02357	Storage	ACQ	670,800	[redacted]
15	Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	[redacted]
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	[redacted]
17	National Fuel - Demand	FSS-O02357	Storage	MDQ	6,098	[redacted]
18	National Fuel	FST N02358	Transportation	MDQ	6,098	[redacted]
19	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	[redacted]
20	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	[redacted]
21	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	[redacted]
22	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	[redacted]
23	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	[redacted]
24	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	[redacted]
25	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	[redacted]
26	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	[redacted]
27	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	[redacted]
28	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	[redacted]
29	ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	[redacted]
30	TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	1,784	[redacted]
31	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	[redacted]
32	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	[redacted]
33	Portland Natural Gas Trans Service	FTN-ENN0005	Transportation	MDQ	1,000	[redacted]
34	Portland Natural Gas	FTN	Transportation	MDQ	1,784	[redacted]
35	ENGIE Demand	NSB041	Peaking	MDQ	10,000	[redacted]
36						
37	**Supply Costs - Commodity**					
38	TGP Supply (Z4)		Pipeline	Dkt	1,299,905	[redacted]
39	Niagara Supply		Pipeline	Dkt	398,527	[redacted]
40	ENGIE COMBO		Pipeline	Dkt	417,491	[redacted]
41	TGP Supply (Direct)		Pipeline	Dkt	1,618,368	[redacted]
42	Dawn Supply		Pipeline	Dkt	480,704	[redacted]
43	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	[redacted]
44	TGP Storage		Storage	Dkt	1,984,133	[redacted]
45	PNGTS		Pipeline	Dkt	104,401	[redacted]
46	Propane Truck		Pipeline	Dkt	44,755	[redacted]
47	LNG Truck		Pipeline	Dkt	216,940	[redacted]
48	Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	[redacted]
49	Propane		Produced	Dkt	95,092	[redacted]
50	LNG Vapor (Storage)		Produced	Dkt	219,916	[redacted]
51						
52	**Supply Costs - Volumetric Transportation**					
53	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	[redacted]
54	Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	[redacted]
55	Niagara Supply		Pipeline	Dkt	398,527	[redacted]
56	Dawn Supply		Pipeline	Dkt	480,704	[redacted]
57	TGP Storage - Withdrawals		Pipeline	Dkt	1,984,133	[redacted]
58	TGP Supply (Direct)		Pipeline	Dkt	1,618,368	[redacted]

Docket No. DG 22-___
Attachment ELM-1

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

Schedule 3
Page 1 of 2

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

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

(a)	Days in Month (b)	Prior Period Bal Apr-18 Ending Bal + May Collections	May-18 31 (c)	Jun-18 30 (d)	Jul-18 31 (e)	Aug-18 31 (f)	Sep-18 30 (g)	Oct-18 31 (h)	Nov-18 30 (i)	Dec-18 31 ( )	Jan-19 31 (k)	Feb-19 28 (l)	Mar-19 31 (m)	Apr-19 30 (n)	May-19 31 (o)	Peak Period Total (p)
Account 1163 1422 Working Capital (Over)/Under Balance Interest Calculation																
Beginning Balance	Account 1163-1422 1/	**$ 4,305**	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 4,305
Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
Prime Rate			4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Forecast Working Capital	ln 34 * 0.091%		315	325	335	335	335	335	7,979	19,792	22,236	19,935	11,469	4,430	-	87,820
Projected Revenues w/o Int.	ln 119 * ln 123		-	-	-	-	-	-	(1,063)	(7,749)	(10,994)	(11,803)	(10,039)	(6,975)	(3,249)	(51,871)
Projected Unb lled Revenue									(4,615)	(6,734)	(7,810)	(6,816)	(5,474)	(3,240)		(34,688)
Reverse Prior Month Unbilled										4,615	6,734	7,810	6,816	5,474	3,240	34,688
Add Net Adjustments			-	-	(8,581)	-	-	-	-	-	-	-	-	-	-	(8,581)
Working Capital Billed	Account 1163-1422 2/	-														-
Monthly (Over)/Under Recovery		$ 4,305	$ 4,620	$ 4,960	$ (3,270)	$ (2,932)	$ (2,608)	$ (2,283)	$ 9	$ 9,930	$ 20,114	$ 29,284	$ 32,123	$ 31,903	$ 31,986	$ 31,673
Average Monthly Balance	(ln 76 + ln 90)/2		$ 4,463	$ 4,798	$ 853	$ (3,099)	$ (2,776)	$ (2,451)	$ (1,141)	$ 4,967	$ 15,030	$ 24,721	$ 30,737	$ 32,059	$ 31,991	
Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Interest Applied	ln 92 * ln 94 / 365 * Days of Month		$ 15	$ 16	$ 3	$ (11)	$ (10)	$ (9)	$ (4)	$ 18	$ 45	$ 66	$ 91	$ 92	$ -	$ 313
(Over)/Under Balance	ln 90 + ln 96	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,986	31,986

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

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

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

Docket No. DG 22-___
Attachment ELM-1

REDACTED
Schedule 4
Page 1 of 1

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

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-18		$ -	$ -	-	$ -	$ -	$ -	[redacted]		$ -	$ -	$ -
10	Jun-18		-	-	-	-	-	-	[redacted]		-	-	-
11	Jul-18	1/	-	-	-	-	-	-	[redacted]		-	-	-
12	Aug-18	1/	-	-	-	-	-	-	[redacted]		-	-	-
13	Sep-18	1/	-	-	-	-	-	-	[redacted]		-	-	-
14	Oct-18	1/	-	-	-	-	-	-	[redacted]		-	-	-
15	Nov-18	1/	-	-	(227,504)	-	(3,273)	-	[redacted]		-	45,000	(515,120)
16	Dec-18	1/	-	-	(368,407)	-	(4,111)	-	[redacted]		-	-	(706,884)
17	Jan-19	1/	-	-	(17,997)	-	(5,091)	-	[redacted]		-	-	(307,129)
18	Feb-19	1/	-	-	703,749	-	(5,254)	-	[redacted]		-	-	383,528
19	Mar-19	1/	-	-	(369,992)	-	(4,696)	-	[redacted]		-	-	(682,508)
20	Apr-19	1/	-	-	(217,609)	-	(3,956)	-	[redacted]		-	-	(528,763)
21													
22	Subtotal May 18 - Oct 18		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23													
24	Subtotal Nov 18 - Apr 19		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
25													
26	Total Peak Period		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
27													

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

Ln											
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										**REDACTED**
2	**d/b/a Liberty Utilities**										**Schedule 5A**
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										**Page 1 of 1**
4	**Demand Costs**										
5											
6				Deferred							Peak
7				to Peak							Nov-Apr
8		Peak	Reference	May 18 -Oct 18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	[redacted]							
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 26 x days								
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 28 x days								
25	Portland Natural Gas		Sch 5B, ln 21 * Sch 5C ln 29 x days								
26	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 22 * Sch 5C ln 30 x days								
27	TransCanada via Union to Portland		Sch 5B, ln 23 * Sch 5C ln 31 x days								
28	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 24 * Sch 5C ln 32 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 25 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 36 x days								
31	National Fuel FST 2358	peak	Sch 5B, ln 27 * Sch 5C ln 38 x days								
32											
33	Subtotal Pipeline Demand Charges			$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 9,738,885
34											
35	**Peaking Supply**										
36	Tenn Gas Pipeline (Concord Latera) Z6-Z6	peak	Sch 5B, ln 30 * Sch 5C ln 26 x days	[redacted]							
37	ENGIE Demand FLS	peak	Per Contract								
38	ENGIE Demand	peak	Per Contract								
39	Subtotal Peaking Demand Charges			$ -	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ -	$ 4,968,750
40											
41	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 33 + ln 39	$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570	$ 14,707,635
42											
43	Less Transportation Capacity Credit			$ (524,979)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (406,202)	$ (4,399,152)
44											
45	**Total Supply, Pipeline & Peaking Demand**			$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368	$ 10,308,483
46											
47											
48	Dominion - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 61 x days	$ 10,464	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 20,928
49	Dominion - Storage	peak	Sch 5B, ln 36 * Sch 5C ln 62 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
50	Honeoye - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 65 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
51	National Fuel - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 67 x days	90,980	15,163	15,163	15,163	15,163	15,163	15,163	181,959
52	National Fuel - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 68 x days	153,345	25,557	25,557	25,557	25,557	25,557	25,557	306,690
53	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 41 * Sch 5C ln 71 x days	195,783	32,631	32,631	32,631	32,631	32,631	32,631	391,567
54	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 42 * Sch 5C ln 72 x days	191,928	31,988	31,988	31,988	31,988	31,988	31,988	383,856
55											
56	**Subtotal Storage Demand Costs**			$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 1,407,802
57											
58	Less Transportation Capacity Credit			$ (281,772)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (485,340)
59											
60	**Total Storage Demand Costs**		ln 56 + ln 58	$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 922,462
61											
62	**Total Demand Charges**		ln 41 + ln 56	$ 2,015,366	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 1,521,887	$ 16,115,438
63											
64	Total Transportation Capacity Credit		ln 43 + ln 58	$ (806,751)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (440,130)	$ (4,884,492)
65											
66	**Total Demand Charges less Cap. Cr.**		ln 62 + ln 64	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757	$ 11,230,946
67											
68							**REDACTED**				

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

		Peak	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply									
	Niagara Supply			3,199	3,199	3,199	3,199	3,199	3,199
Pipeline									
	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline		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		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Tenn Gas Pipeline (Concord Lateral)		Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
	Portland Natural Gas Trans Service		FTN-ENN0005	1,000	1,000	1,000	1,000	1,000	1,000
	Portland Natural Gas		FTN	1,784	1,784	1,784	1,784	1,784	1,784
	ANE (TransCanada via Union to Iroquois)		Union Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	TransCanada via Union to Portland		Union Parkway to Portland	1,784	1,784	1,784	1,784	1,784	1,784
	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
Peaking									
	Tenn Gas Pipeline (Concord Lateral)	peak		0	0	0	0	0	0
	ENGIE Demand FLS	peak		3,000	3,000	3,000	3,000	3,000	0
	ENGIE Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	0
Storage									
	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
	Honeoye - Capacity	peak	SS-NY	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

Line					Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov - Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Demand Rates**										
5					Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov - Apr
6	**Tariff Rates**				30	31	31	28	31	30	181
7					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
8	**Supply**										
9	Niagara Supply		[redacted]	Per Contract	[redacted]						
10											
11	**Pipeline**										
12	Iroquois Gas Trans Service	RTS 470-01	$5.5997	First Revised Sheet No. 4	$0.1867	$0.1806	$0.1806	$0.2000	$0.1806	$0.1867	$0.1859
13											
14	Tenn Gas Pipeline	95346 Z5-Z6	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0.2386	$0.2376
15											
16	Tenn Gas Pipeline	2302 Z5-Z6	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0.2386	$0.2376
17											
18	Tenn Gas Pipeline	8587 Z0-Z6	$23.2175	FT-A (Z0 - Z6)	$0.7739	$0.7490	$0.7490	$0.8292	$0.7490	$0.7739	$0.7706
19											
20	Tenn Gas Pipeline	8587 Z1-Z6	$20.6094	FT-A (Z1 - Z6)	$0.6870	$0.6648	$0.6648	$0.7361	$0.6648	$0.6870	$0.6841
21											
22	Tenn Gas Pipeline	8587 Z4-Z6	$8.1481	FT-A (Z4 - Z6)	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2705
23											
24	TGP Dracut	42076 FTA Z6-Z6	$4.7453	11th Rev Sheet No. 14	$0.1582	$0.1531	$0.1531	$0.1695	$0.1531	$0.1582	$0.1575
25											
26	TGP Concord Lateral	Firm Transportatio	$12.1916	Per contract	$0.4064	$0 3933	$0.3933	$0.4354	$0.3933	$0.4064	$0.4047
27											
28	Portland Natural Gas	FTN-ENN0005	$18.2633	Dmd is Negot/CMDY=Part 4.1 \	$0.6088	$0 5891	$0.5891	$0.6523	$0.5891	$0.6088	$0.6062
29											
30	Portland Natural Gas	FTN	$22.8125	Dmd is Negot/CMDY=Part 4.1 \	$0.7604	$0.7359	$0.7359	$0.8147	$0.7359	$0.7604	$0.7572
31											
32	Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.1481	11th Rev Sheet No. 14	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2705
33											
34	Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.1481	11th Rev Sheet No. 14	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0 2716	$0.2705
35											
36	Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0 2386	$0.2376
37											
38	National Fuel	FST N02358	$3.6874	4.010 Version 21.0.1 Pg 1	$0.1229	$0.1189	$0.1189	$0.1317	$0.1189	$0.1229	$0.1224
39											
40	ANE Union Gas		$3.7160								
41	TransCanada Pipelines Limited		$13 34166	Union Parkway to Iroquois							
42	Delivery Pressure Demand Charge		0.6704	Union Parkway to Iroquois							
43	Sub Total Demand Charges		17.7280								
44	Conversion rate GJ to MMBTU		1.0551								
45	Conversion rate to US$		1.2851	updated 7/6/18							
46	Demand Rate/US$		$14.5544		$0.4851	$0.4695	$0.4695	$0.5198	$0.4695	$0.4851	$0.4831
47											
48	Union Gas		$3.7160								
49	TransCanada Pipelines Limited		$22.4898	Union Parkway to Portland							
50	Delivery Pressure Demand Charge		$0.6704	Union Parkway to Portland							
51	Sub Total Demand Charges		26.8762								
52	Conversion rate GJ to MMBTU		1.0551								
53	Conversion rate to US$		1.2851	updated 7/6/18							
54	Demand Rate/US$		$22.0649		$0.7355	$0.7118	$0.7118	$0.7880	$0.7118	$0.7355	$0.7324
55											
56	**Peaking**										
57	ENGIE Demand FLS		[redacted]	Per Contract	[redacted]						
58	Subtotal Peaking Demand Charges			Per Contract							
59											
60	**Storage**										
61	Dominion - Demand	GSS 300076	$1.8672	GSS Settled,Tariff Rec #10.30 \	$0.0622	$0.0602	$0.0602	$0.0667	$0.0602	$0.0622	$0.0619
62	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
63			$1.8817		$0.0627	$0.0607	$0.0607	$0.0672	$0.0607	$0.0627	$0.0624
64											
65	Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0 2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
66											

1360

070

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

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

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

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

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

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

2018 CURRENT:

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

2017 TRUE-UP:

Debit/Credit Cost ($316,993) divided by 47,717,356,257 Dth	=	(0.0000066431)
TOTAL UNIT CHARGE	=	0.0013295571

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

PUBLIC

Dominion Energy Transmission, Inc.
FERC Gas Tariff
Fifth Revised Volume No. 1

GSS, GSS-E & ISS Rates - Settled Parties
Tariff Record No. 10.30.
Version 2.0.0
Superseding Version 1.0.0

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

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

Issued On: September 29, 2017

Effective On: November 1, 2017

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

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

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

(Footnotes continued on Sheet 4.01)

074

1364

1/ Transporter's Settlement dated August 18, 2016, in Docket No. RP16-301-000, which was approved by Commission order issued October 20, 2016, established new base tariff recourse rates referred to as "Settlement Rates" and a moratorium on changes to the Settlement Rates until September 1, 2020. All recourse Maximum and Minimum Rates listed on Sheet Nos. 4, 4B, 4C, and 5A are Settlement Rates subject to the moratorium.
2/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity 1/	

MEASUREMENT VARIANCE/FUEL USE FACTOR:

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

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

RATES FOR PART 284 STORAGE SERVICES

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

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 0.89%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ Rate per nomination.
7/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.1033 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.
8/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0015 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

Effective On: April 1, 2018

RATES FOR TRANSPORTATION SERVICES

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

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

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

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

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

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

Statement of Transportation Rates
(Rates per DTH)

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

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

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

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

Eleventh Revised Sheet No. 14
Superseding
Tenth 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	$5.5411		$11.5794	$15.5758	$15.8514	$17.4175	$18.4879	$23.1959
L		$4.9193						
1	$8.3417		$7.9962	$10.6413	$15.0745	$14.8460	$16.7429	$20.5878
2	$15.5759		$10.5774	$5.5014	$5.1427	$6.5803	$9.0504	$11.6830
3	$15.8514		$8.3784	$5.5458	$4.0009	$6.1457	$11.1149	$12.8437
4	$20.1259		$18.5544	$7.0708	$10.7456	$5.2598	$5.6884	$8.1265
5	$23.9973		$16.8625	$7.4172	$8.9748	$5.8432	$5.4810	$7.1353
6	$27.7603		$19.3678	$13.3296	$14.6845	$10.3726	$5.4568	$4.7237

Daily Base
Reservation Rate 1/

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

Maximum Reservation
Rates 2/, 3/

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

Notes:

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

Issued: September 29, 2017
Effective: November 1, 2017

Docket No. RP17-1118-000
Accepted: October 26, 2017

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum Commodity Rates 1/, 2/

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

Maximum Commodity Rates 1/, 2/, 3/

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

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0009.

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FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Fourteenth Revised Sheet No. 61
Superseding
Thirteenth Revised Sheet No. 61

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

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

Notes:

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

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

Thirteenth Revised Sheet No. 32
Superseding
Twelfth Revised Sheet No. 32

FUEL AND EPCR

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

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

EPCR 3/, 4/

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

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

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

Storage Transportation Service

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

Firm Transportation - Short Notice

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

Dawn Long Term Fixed Price

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

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

Enhanced Market Balancing Service

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

Delivery Pressure

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

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

Union Dawn Receipt Point Surcharge

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

Short Notice Balancing (SNB) Service

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

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

Energy Deficient Gas Allowance (EDGA) Service

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

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

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

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

TRANSPORTATION RATES

(A) Applicability

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

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

(B) Services

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

(C) Rates

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

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

REDACTED

Ln									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas**								
12	Dawn Supply	ln 64 * ln 104	[redacted]						
13	Niagara Supply	ln 65 * ln 109							
14	TGP Supply (Direct)	ln 66 * ln 125							
15	Dracut Supply 1 - Baseload	ln 67 * ln 114							
16	Dracut Supply 2 - Swing	ln 68 * ln 119							
17	ENG E COMBO	ln 69 * ln 131							
18	LNG Truck	ln 70 * ln 133							
19	Propane Truck	ln 71 * ln 135							
20	PNGTS	ln 72 * ln 140							
21	Portland Natural Gas	ln 73 * ln 145							
22	TGP Supply (Z4)	ln 74 * ln 150							
23									
24	Subtotal Pipeline Gas Costs		$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499	$ 42,563,780
25									
26	**Volumetric Transportation Costs**								
27	Dawn Supply	ln 64 * ln 197	[redacted]						
28	Niagara Supply	ln 65 * ln 208							
29	TGP Supply (Direct)	ln 66 * ln 235							
30	Dracut Supply 1 - Baseload	ln 67 * ln 256							
31	Dracut Supply 2 - Swing	ln 68 * ln 256							
32	ENG E COMBO	ln 69 * ln 256							
33	TGP Storage - Withdrawals	ln 79 * ln 172							
34									
35	**Total Volumetric Transportation Costs**		$ 215,648	$ 213,629	$ 237,663	$ 219,674	$ 201,319	$ 38,974	$ 1,126,907
36									
37	**Less - Gas Refill**								
38	LNG Truck	ln 88 * ln 157	[redacted]						
39	Propane	ln 89 * ln 158							
40	TGP Storage Refill	ln 90 * ln 123							
41	Storage Refill (Trans.)	ln 90 * ln 235							
42									
43	Subtotal Refills		$ (765,580)	$ (131,625)	$ (809,867)	$ (600,010)	$ (65,260)	$ -	$ (2,372,341)
44									
45	**Total Supply & Pipeline Commodity Costs**	ln 24 + ln 35 + ln 43	$ 2,553,342	$ 8,898,538	$ 11,299,833	$ 10,827,598	$ 5,600,561	$ 2,138,473	$ 41,318,346
46									
47	**Storage Gas**								
48	TGP Storage - Withdrawals	ln 79 * ln 164	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894	$ 5,125,663
49									
50	**Produced Gas**								
51	LNG Vapor	ln 82 * ln 152	[redacted]						
52	Propane	ln 83 * ln 154							
53									
54	**Total Produced Gas**	ln 51 + ln 52	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567	$ 2,672,211
55									
56									
57	**Total Commodity Gas & Trans. Costs**	ln 45 + ln 48 + ln 54	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935	$ 49,116,221
58									$ 87,958,623
59									

REDACTED

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

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

REDACTED

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

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REDACTED

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

REDACTED

Ln									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
211									
212									
213	**TGP Direct Volumetric Transportation Charge**								Average Rate
214	**Commodity Costs**	Ln 123	[redacted]						
215									
216	TGP - Max Comm. Base Rate - Z 0-6	13th Rev Sheet No. 15	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039
217	TGP - Max Commodity ACA Rate - Z 0-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
218	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052
219	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
220	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**
221	TGP - Max Comm. Base Rate - Z 1-6	13th Rev Sheet No. 15	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650
222	TGP - Max Commodity ACA Rate - Z 1-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
223	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663
224	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**
226	TGP - Fuel Charge % - Z 0 -6	13th Rev Sheet No. 32	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%
227	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
228	Prorated TGP Fuel Charge % - Z 0-6		1.45%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%
229	TGP - Fuel Charge % - Z 1 -6	13th Rev Sheet No. 32	3.88%	3.88%	3.88%	3 88%	3.88%	3.88%	3.88%
230	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
231	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
232	TGP - Fuel Charge % - Z 0-6	ln 215 x ln 229	**$0.00427**	**$0.00440**	**$0.00453**	**$0.00447**	**$0.00432**	**$0.00387**	**$0.00431**
233	TGP - Fuel Charge % - Z 1-6	ln 215 x ln 232	**$0.00771**	**$0.00796**	**$0.00818**	**$0.00808**	**$0.00781**	**$0.00699**	**$0.00779**
234	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03987**	**$0.04026**	**$0.04060**	**$0.04045**	**$0.04003**	**$0.03876**	**$0.04000**
235									
236	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
237	**Commodity Costs**	Ln 123	[redacted]						
238									
239	TGP - Max Comm. Base Rate - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
240	TGP - Max Commodity ACA Rate - Z 6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
241	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
242	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
243	TGP - Fuel Charge	ln 238 x ln 243	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**
244	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**
245									
246									
247	**TGP Dracut**								
248	**Commodity Costs - NYMEX Price**	Ln 114	[redacted]						
249									
250	TGP - Trans Charge - Comm. - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
251	TGP - Trans Charge - ACA Rate - Z6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
252	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
253	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
254	TGP - Fuel Charge	ln 249 x ln 254	[redacted]						
255	**Total Volumetric Transportation Rate - TGP Dracut**								
256									
257					**REDACTED**				

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**NYMEX Futures @ Henry Hub**										
5											Peak
6	For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19		Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)		(i)
8	**I. NYMEX Opening Prices as of**										
9	Opening Prices (15 day average)			2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$	2.9782
10	NYMEX		**Filed COG**	2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$	2.9782

1383

093

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

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

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

November 1, 2018 - April 30, 2019 / **May 1, 2018 - October 31, 2018**
Residential Heating (R3)

PROPOSED			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
	5/1/2018	7/1/2018															
Winter:																	
Cust. Chg	$24.43	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12								
Headblock	$0.3863	$0.5631	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.3197	$0.5631	$21.33	$53.70	$88.19	$78.12	$60.12	$56.40	$357.86								
HB Threshold	100	-															
Summer:																	
Cust. Chg	$14.88	$15.02								$14.88	$14.88	$15.02	$15.02	$15.02	$15.02	$89.84	$179.96
Headblock	$0.5580	$0.5631								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.5580	$0.5631								$30.99	$11.84	$9.43	$8.47	$8.80	$10.15	$79.67	$437.53
HB Threshold	-	-															
Total Base Rate Amount			$36.35	$68.72	$103.21	$93.14	$75.14	$71.42	$447.98	$45.87	$26.72	$24.45	$23.49	$23.82	$25.17	$169.51	$617.49
COG Rate - (Seasonal)			$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.3133	$0.3916	$0.3127	$0.3665	$0.3916	$0.3916	$0.3491	$0.6694
COG amount			$28.07	$70.68	$116.07	$102.82	$79.12	$74.23	$470.98	$17.40	$8.31	$5.24	$5.51	$6.12	$7.06	$49.63	$520.62
LDAC			$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0856
LDAC amount			$3.17	$7.98	$13.10	$11.60	$8.93	$8.38	$53.15	$5.25	$2.00	$1.58	$1.42	$1.48	$1.70	$13.44	$66.59
Total Bill			**$67.58**	**$147.37**	**$232.37**	**$207.57**	**$163.19**	**$154.03**	**$972.12**	**$68.51**	**$37.03**	**$31.27**	**$30.42**	**$31.42**	**$33.93**	**$232.58**	**$1,204.70**

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Residential Heating (R3)

CURRENT			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
Winter:	5/1/2017	7/1/2017															
Cust. Chg	$22.10	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58								
Headblock	$0.3495	$0.3863	$14.63	$36.84	$38.63	$38.63	$38.63	$38.63	$205.99								
Tailblock	$0.2892	$0.3197	$0.00	$0.00	$18.10	$12.39	$2.16	$0.05	$32.70								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$22.10	$24.43								$22.10	$22.10	$24.43	$24.43	$24.43	$24.43	$141.92	$288.50
Headblock	$0.3495	$0.3863								$6.99	$6.99	$6.47	$5.81	$6.04	$6.96	$39.26	$245.25
Tailblock	$0.2892	$0.3197								$10.27	$0.35	$0.00	$0.00	$0.00	$0.00	$10.63	$43.32
HB Threshold	20	20															
Total Base Rate Amount			$39.06	$61.27	$81.16	$75.45	$65.22	$63.11	$385.27	$39.36	$29.44	$30.90	$30.24	$30.47	$31.39	$191.81	$577.08
COG Rate - (Seasonal)			$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7321	$0.4368	$0.4368	$0.4368	$0.4725	$0.4725	$0.4725	$0.4490	$0.6804
COG amount			$24.41	$61.46	$100.94	$111.77	$86.01	$80.69	$465.28	$24.26	$9.27	$7.31	$7.11	$7.39	$8.52	$63.84	$529.12
LDAC			$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0817
LDAC amount			$3.24	$8.16	$13.41	$11.88	$9.14	$8.57	$54.40	$3.55	$1.36	$1.07	$0.96	$1.00	$1.15	$9.10	$63.50
Total Bill			**$66.71**	**$130.90**	**$195.50**	**$199.09**	**$160.37**	**$152.38**	**$904.95**	**$67.17**	**$40.07**	**$39.28**	**$38.31**	**$38.85**	**$41.07**	**$264.75**	**$1,169.70**

DIFFERENCE:

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter Nov-Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Summer May-Oct**	**Total Nov-Oct**
Total Bill	**$0.87**	**$16.48**	**$36.87**	**$8.48**	**$2.82**	**$1.65**	**$67.17**	**$1.34**	**($3.04)**	**($8.02)**	**($7.89)**	**($7.43)**	**($7.13)**	**($32.17)**	**$35.00**
% Change	**1.30%**	**12.59%**	**18.86%**	**4.26%**	**1.76%**	**1.08%**	**7.42%**	**1.99%**	**-7.58%**	**-20.41%**	**-20.59%**	**-19.13%**	**-17.37%**	**-12.15%**	**2.99%**
Base Rate	($2.71)	$7.45	$22.05	$17.70	$9.92	$8.31	$62.71	$6.50	($2.72)	($6.45)	($6.75)	($6.65)	($6.22)	($22.29)	$40.42
% Change	-6.95%	12.16%	27.17%	23.46%	15.20%	13.17%	16.28%	16.51%	-9.25%	-20.87%	-22.33%	-21.81%	-19.82%	-11.62%	7.00%
COG & LDAC	$3.58	$9.03	$14.82	($9.22)	($7.10)	($6.66)	$4.46	($5.16)	($0.31)	($1.57)	($1.14)	($0.79)	($0.91)	($9.88)	($5.42)
% Change	14.68%	14.68%	14.68%	-8.25%	-8.25%	-8.25%	0.96%	-21.29%	-3.37%	-21.43%	-15.98%	-10.67%	-10.67%	-15.47%	-1.02%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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

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

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

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

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

DIFFERENCE:

Total Bill			**$9.42**	**$38.32**	**$66.43**	**($12.85)**	**($8.22)**	**($6.97)**	**$86.13**	**$10.41**	**$6.77**	**$1.22**	**$4.62**	**$3.37**	**($1.30)**	**$25.09**	**$111.22**
% Change			**5.86%**	**11.06%**	**11.57%**	**-2.14%**	**-1.81%**	**-1.68%**	**3.38%**	**6.73%**	**8.24%**	**1.60%**	**5.77%**	**4.46%**	**-1.56%**	**4.54%**	**3.59%**
Base Rate			($0.05)	$8.74	$12.64	$11.82	$9.66	$9.08	$51.88	$22.76	$6.92	$3.40	$6.79	$4.36	($0.15)	$44.08	$95.97
% Change			-0.05%	5.85%	5.85%	5.85%	5.85%	5.85%	5.26%	27.27%	10.79%	5.27%	10.73%	6.91%	-0.21%	10.82%	6.89%
COG & LDAC			$9.47	$29.59	$53.79	($24.68)	($17.88)	($16.04)	$34.25	($12.36)	($0.15)	($2.17)	($2.17)	($0.99)	($1.15)	($18.99)	$15.26
% Change			16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.39%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-14.42%	0.98%
check			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-42

November 1, 2018 - April 30, 2019 — **May 1, 2018 - October 31, 2018**

C&I High Winter Use Medium G-42

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

November 1, 2017 - April 30, 2018 — **May 1, 2017 - October 31, 2017**

C&I High Winter Use Medium G-42

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

DIFFERENCE:

Total Bill	**$117.35**	**$284.88**	**$470.73**	**($113.84)**	**($82.97)**	**($74.98)**	**$601.17**	**($33.23)**	**$31.77**	**($7.51)**	**($0.79)**	**$5.04**	**$3.88**	**($0.85)**	**$600.32**
% Change	**10.85%**	**11.72%**	**12.03%**	**-2.73%**	**-2.55%**	**-2.49%**	**3.37%**	**-2.96%**	**5.85%**	**-1.85%**	**-0.21%**	**1.25%**	**0.83%**	**-0.03%**	**2.83%**
Base Rate	$28.73	$51.23	$74.93	$70.22	$57.69	$54.45	$337.25	$73.48	$33.61	$16.02	$15.14	$15.65	$17.32	$171.21	$508.47
% Change	5.85%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	14.41%	10.59%	5.85%	5.85%	5.85%	5.85%	8.90%	6.62%
COG & LDAC	$88.61	$233.65	$395.80	($184.06)	($140.66)	($129.43)	$263.92	($106.71)	($1.84)	($23.54)	($15.93)	($10.61)	($13.45)	($172.07)	$91.85
% Change	16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.38%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-13.56%	0.74%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Docket No. DG 22-___
Attachment ELM-1

Schedule 8
Page 4 of 5

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty Utilities**
2 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-52**
5
6
7 **November 1, 2018 - April 30, 2019**
8 **Commercial Rate (G-52)**

Line	PROPOSED			Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr
11	**average Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,306
12										
13	**Winter:**	7/1/2018	5/1/2018							
14	Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50
15	Headblock	$0.2401	$0.2268	$240.10	$240.10	$240.10	$240.10	$240.10	$240.10	$1,440.60
16	Tailblock	$0.1600	$0.1511	$56.28	$138.55	$205.37	$185.54	$141.69	$121.61	$849.04
17	HB Threshold	1,000	1,000							
18										
19	**Summer:**									
20	Cust. Chg	$169.75	$168.21							
21	Headblock	$0.1740	$0.1724							
22	Tailblock	$0.0989	$0.0980							
23	HB Threshold	1,000	1,000							
24										
25	Total Base Rate Amount			$466.13	$548.40	$615.22	$595.39	$551.54	$531.46	$3,308.14
26										
27	COG Rate - (Seasonal)			$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456
28	COG amount			$1,007.86	$1,391.23	$1,702.65	$1,610.22	$1,405.86	$1,312.30	$8,430.11
29										
30	LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772
31	LDAC amount			$104.30	$143.97	$176.19	$166.63	$145.48	$135.80	$872.37
32										
33	**Total Bill**			**$1,578.29**	**$2,083.59**	**$2,494.07**	**$2,372.23**	**$2,102.88**	**$1,979.56**	**$12,610.61**

May 1, 2018 - October 31, 2018

Line	PROPOSED	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
11	**average Usage (Therms)**	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
20	Cust. Chg	$168.21	$168.21	$169.75	$169.75	$169.75	$169.75	$1,015.42	$2,033.92
21	Headblock	$172.40	$172.40	$174.00	$174.00	$174.00	$156.04	$1,022.84	$2,463.44
22	Tailblock	$49.15	$12.63	$3.16	$2.48	$4.92	$0.00	$72.35	$921.38
25	Total Base Rate Amount	$389.76	$353.24	$346.91	$346.23	$348.67	$325.79	$2,110.61	$5,418.74
27	COG Rate - (Seasonal)	$0.3299	$0.4124	$0.3335	$0.3873	$0.4124	$0.4124	$0.3776	$0.6096
28	COG amount	$493.86	$465.08	$344.16	$397.00	$432.94	$369.83	$2,502.87	$10,932.98
30	LDAC	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0768
31	LDAC amount	$114.22	$86.05	$78.74	$78.21	$80.10	$68.42	$505.74	$1,378.11
33	**Total Bill**	**$997.85**	**$904.37**	**$769.80**	**$821.44**	**$861.71**	**$764.05**	**$5,119.22**	**$17,729.83**

34
35 **November 1, 2017 - April 30, 2018**
36 **Commercial Rate (G-52)**

Line	CURRENT			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr
39	**average Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,306
40										
41	**Winter:**	5/1/2017	7/1/2017							
42	Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16
43	Headblock	$0.2052	$0.2268	$226.80	$226.80	$226.80	$226.80	$226.80	$226.80	$1,360.80
44	Tailblock	$0.1367	$0.1511	$53.15	$130.84	$193.95	$175.22	$133.81	$114.84	$801.81
45	HB Threshold	1,000	1,000							
46										
47	**Summer:**									
48	Cust. Chg	$145.08	$160.36							
49	Headblock	$0.1487	$0.1644							
50	Tailblock	$0.0845	$0.0934							
51	HB Threshold	1,000	1,000							
52										
53	Total Base Rate Amount			$440.31	$518.00	$581.11	$562.38	$520.97	$502.00	$3,124.77
54										
55	COG Rate - (Seasonal)			$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7397
56	COG amount			$886.74	$1,224.04	$1,498.04	$1,764.63	$1,546.14	$1,443.25	$8,362.84
57										
58	LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674
59	LDAC amount			$91.11	$125.76	$153.91	$145.56	$127.09	$118.63	$762.06
60										
61	**Total Bill**			**$1,418.16**	**$1,867.80**	**$2,233.06**	**$2,472.57**	**$2,194.19**	**$2,063.88**	**$12,249.67**

May 1, 2017 - October 31, 2017

Line	CURRENT	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
39	**average Usage (Therms)**	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
48	Cust. Chg	$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
49	Headblock	$148.70	$148.70	$164.40	$164.40	$164.40	$147.43	$938.03	$2,298.83
50	Tailblock	$32.97	$7.82	$2.98	$2.34	$4.65	$0.00	$50.76	$852.57
53	Total Base Rate Amount	$326.75	$301.60	$327.74	$327.10	$329.41	$307.79	$1,920.40	$5,045.16
55	COG Rate - (Seasonal)	$0.4574	$0.4574	$0.4574	$0.4931	$0.4931	$0.4931	$0.4734	$0.6413
56	COG amount	$684.73	$515.83	$472.01	$505.45	$517.65	$442.21	$3,137.88	$11,500.72
58	LDAC	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0591
59	LDAC amount	$67.37	$50.75	$46.44	$46.13	$47.24	$40.36	$298.27	$1,060.33
61	**Total Bill**	**$1,078.85**	**$868.18**	**$846.20**	**$878.68**	**$894.31**	**$790.35**	**$5,356.55**	**$17,606.22**

62
63 **DIFFERENCE:**

Line		Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
64	**Total Bill**	**$160.13**	**$215.79**	**$261.00**	**($100.33)**	**($91.32)**	**($84.32)**	**$360.95**
65	% Change	**11.29%**	**11.55%**	**11.69%**	**-4.06%**	**-4.16%**	**-4.09%**	**2.95%**
66								
67	**Base Rate**	$25.82	$30.40	$34.11	$33.01	$30.57	$29.45	$183.37
68	% Change	5.86%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%
69								
70	**COG & LDAC**	$134.31	$185.39	$226.89	($133.34)	($121.89)	($113.78)	$177.58
71	% Change	15.15%	15.15%	15.15%	-7.56%	-7.88%	-7.88%	2.12%
	check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Line		May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
64	**Total Bill**	**($81.00)**	**$36.19**	**($76.39)**	**($57.24)**	**($32.60)**	**($26.30)**	**($237.34)**	**$123.61**
65	% Change	**-7.51%**	**4.17%**	**-9.03%**	**-6.51%**	**-3.64%**	**-3.33%**	**-4.43%**	**0.70%**
66									
67	**Base Rate**	$63.01	$51.64	$19.17	$19.13	$19.26	$18.00	$190.21	$373.58
68	% Change	19.28%	17.12%	5.85%	5.85%	5.85%	5.85%	9.90%	7.40%
69									
70	**COG & LDAC**	($144.01)	($15.45)	($95.56)	($76.37)	($51.86)	($44.30)	($427.55)	($249.97)
71	% Change	-21.03%	-3.00%	-20.24%	-15.11%	-10.02%	-10.02%	-13.63%	-2.17%
	check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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

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

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

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

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

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **2017-2018 Winter Calculation**
4 **Correction Factor Calculation**

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

Line			
26	Total Sales	33,607,703	
27	Low Winter Use	4,889,046	
28	Winter Ratio for Low Winter Use	**1.0335**	Schedule 10A p 2, ln 74
29	High Winter Use	28,718,657	
30	Winter Ratio for High Winter Use	**0.9930**	Schedule 10A p 2, ln 66

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

33 Correction Factor = **100.1110%**

36 **Allocation Calculation for Miscellaneous Overhead**

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

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

7 **Firm Sales**							**Subtotal**							**Subtotal**	
8	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**PK 18-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**OP 19**	**Total**
9 R-1	58,148	73,323	85,127	87,489	80,107	60,928	445,123	44,082	30,039	23,238	24,503	31,923	43,218	197,003	642,126
10 R-3	4,041,030	7,405,866	10,502,345	11,246,925	9,528,683	6,407,575	49,132,423	3,690,099	1,773,275	1,006,300	981,527	1,481,613	2,659,147	11,591,962	60,724,385
11 R-4	225,090	424,725	668,812	822,921	728,538	573,586	3,443,671	361,052	178,352	90,516	79,349	97,393	150,109	956,771	4,400,443
12 Total Residential.	4 324 268	7 903 914	11 256 284	12 157 335	10 337 327	7 042 089	53 021 218	4 095 234	1 981 666	1 120 055	1 085 379	1 610 929	2 852 473	12 745 736	65 766 954
13															
14 G-41	1,321,101	2,319,276	3,165,299	3,498,870	2,926,465	1,918,416	15,149,429	800,746	362,796	221,001	168,493	181,679	460,013	2,194,729	17,344,157
15 G-42	895,704	1,551,977	2,083,542	2,176,169	1,812,337	1,285,485	9,805,213	748,675	460,256	231,012	116,114	74,965	227,916	1,858,939	11,664,152
16 G-43	360,692	504,475	733,059	836,182	731,266	598,340	3,764,015	304,113	197,948	134,668	105,947	121,390	192,087	1,056,153	4,820,168
17 G-51	135,964	177,998	217,956	227,659	210,007	162,636	1,132,220	115,160	74,244	56,098	56,385	71,155	94,990	468,032	1,600,252
18 G-52	146,420	183,177	224,756	238,484	224,688	178,727	1,196,252	131,291	88,424	68,817	68,840	84,354	107,862	549,588	1,745,840
19 G-53	156,779	249,279	616,066	508,733	461,553	413,241	2,405,652	291,255	205,865	165,249	156,854	172,243	202,036	1,193,502	3,599,154
20 G-54	23,619	24,600	26,018	27,451	27,760	25,474	154,923	23,468	19,194	16,830	17,609	20,668	21,777	119,546	274,468
21 Total C/I	3 040 279	5 010 783	7 066 697	7 513 549	6 394 077	4 582 318	33 607 703	2 414 708	1 408 727	893 675	690 242	726 454	1 306 681	7 440 489	41 048 192
22															
23 **Sales Volume**	**7,364,547**	**12,914,697**	**18,322,981**	**19,670,884**	**16,731,404**	**11,624,407**	**86,628,921**	**6,509,942**	**3,390,393**	**2,013,730**	**1,775,621**	**2,337,384**	**4,159,155**	**20,186,225**	**106,815,146**
24															
25 Transportation Sales															
26															
27 G-41	575,879	819,379	1,110,280	1,198,083	994,081	780,156	5,477,859	419,152	223,968	126,739	130,012	177,081	307,285	1,384,236	6,862,094
28 G-42	1,709,642	2,476,139	3,396,451	3,680,772	3,051,299	2,391,810	16,706,114	1,277,699	653,670	331,128	308,102	424,112	829,661	3,824,373	20,530,487
29 G-43	916,199	1,344,906	1,729,807	1,910,992	1,765,170	1,398,691	9,065,765	1,166,024	718,428	474,845	407,575	463,279	699,961	3,930,112	12,995,877
30 G-51	42,394	46,822	55,046	63,877	60,806	58,506	327,451	77,824	67,235	64,233	77,040	88,667	80,334	455,334	782,784
31 G-52	222,033	234,604	257,794	277,352	269,034	248,554	1,509,370	283,695	260,424	264,769	323,847	380,983	356,910	1,870,628	3,379,999
32 G-53	465,205	609,368	785,673	886,023	881,490	807,226	4,434,985	739,996	529,662	363,450	297,063	282,627	351,494	2,564,292	6,999,276
33 G-54	2,364,482	2,375,492	2,456,766	2,089,499	2,011,618	1,925,018	13,222,874	1,781,763	1,808,656	1,788,616	1,955,455	2,061,440	2,219,044	11,614,976	24,837,850
34															
35 Total Trans. Sales	**6,295,834**	**7,906,710**	**9,791,817**	**10,106,599**	**9,033,498**	**7,609,960**	**50,744,418**	**5,746,154**	**4,262,044**	**3,413,780**	**3,499,094**	**3,878,188**	**4,844,690**	**25,643,949**	**76,388,368**
36															
37 Total All Sales	**13,660,381**	**20,821,407**	**28,114,798**	**29,777,484**	**25,764,902**	**19,234,367**	**137,373,339**	**12,256,096**	**7,652,437**	**5,427,510**	**5,274,715**	**6,215,572**	**9,003,844**	**45,830,174**	**183,203,513**

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Normal and Design Year Volumes** — **Schedule 11A**
5 **Page 1 of 1**
6
7 **Volumes (Therms)** **Normal Year**
8
9 **For the Months of November 18 - April 19**
10

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
13	Pipeline Gas:							
14	Dawn Supply	796,342	878,932	897,468	806,735	883,624	543,941	4,807,042
15	Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
16	TGP Supply (Gulf)	4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382	16,183,681
17	Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
18	Dracut Supply 2 - Swing	2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232	11,732,071
19	ENGIE Combo	-	945,993	1,229,648	1,264,827	734,441	-	4,174,908
20	LNG Truck	18,690	289,648	685,485	1,029,982	145,597	-	2,169,402
21	Propane Truck	-	-	356,219	91,328	-	-	447,548
22	PNGTS	198,251	197,617	108,541	146,415	191,500	201,686	1,044,010
23	Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	260,087	2,111,074
24	TGP Supply (Z4)	1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079	12,999,054
25	Subtotal Pipeline Volumes	10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703	69,847,042
26								
27	Storage Gas:							
28	TGP Storage	1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558	19,841,326
29								
30	Produced Gas:							
31	LNG Vapor	18,690	289,648	777,271	1,029,982	64,550	19,014	2,199,156
32	Propane	-	-	859,588	91,328	-	-	950,916
33	Subtotal Produced Gas	18,690	289,648	1,636,859	1,121,310	64,550	19,014	3,150,073
34								
35	Less - Gas Refills:							
36	LNG Truck	(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-	(2,169,402)
37	Propane	-	-	(356,219)	(91,328)	-	-	(447,548)
38	TGP Storage Refill	(2,262,867)	-	-	-	-	-	(2,262,867)
39	Subtotal Refills	(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-	(4,879,817)
40								
41	Total Sendout Volumes	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276	87,958,623
42								

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
43 **Normal and Design Year Volumes** **Schedule 11B**
44 **Page 1 of 1**
45
46 **Volumes (Therms)** **Design Year**
47
48 **For the Months of November 18 - April 19**
49

Line		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
52	Pipeline Gas:							
53	Dawn Supply	796,342	878,932	897,468	806,735	883,624	617,960	4,881,061
54	Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
55	TGP Supply (Gulf)	4,154,598	2,956,407	3,018,756	2,713,035	2,876,080	584,686	16,303,562
56	Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
57	Dracut Supply 2 - Swing	3,107,938	3,496,465	3,388,088	3,348,710	4,354,285	2,136,377	19,831,864
58	ENGIE Combo	-	1,277,020	1,048,260	1,113,337	730,137	-	4,168,754
59	LNG Truck	19,358	54,220	759,788	885,016	452,570	-	2,170,952
60	Propane Truck	-	-	303,770	144,966	-	-	448,735
61	PNGTS	198,251	219,020	115,097	158,013	205,844	201,686	1,097,911
62	Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	311,697	2,162,684
63	TGP Supply (Z4)	1,641,413	1,819,931	1,858,313	1,670,006	1,829,646	4,234,727	13,054,036
64	Subtotal Pipeline Volumes	10,889,131	14,422,474	16,991,430	14,861,168	12,410,180	8,723,428	78,297,812
65								
66	Storage Gas:							
67	TGP Storage	1,371,738	4,289,074	5,080,310	4,651,952	3,946,183	155,509	19,494,766
68								0
69	Produced Gas:							0
70	LNG Vapor	18,690	54,933	851,575	885,016	371,524	19,014	2,200,752
71	Propane	-	-	807,138	144,966	-	-	952,104
72	Subtotal Produced Gas	18,690	54,933	1,658,713	1,029,982	371,524	19,014	3,152,857
73								
74	Less - Gas Refills:							
75	LNG Truck	(19,358)	(54,220)	(759,788)	(885,016)	(452,570)	-	-2,170,952
76	Propane	-	-	(303,770)	(144,966)	-	-	-448,735
77	TGP Storage Refill	(1,843,002)	-	-	-	-	-	-1,843,002
78	Subtotal Refills	(1,862,360)	(54,220)	(1,063,558)	(1,029,982)	(452,570)	-	(4,462,690)
79								
80	Total Sendout Volumes	10,417,200	18,712,261	22,666,896	19,513,121	16,275,316	8,897,951	96,482,745

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

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

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

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

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

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

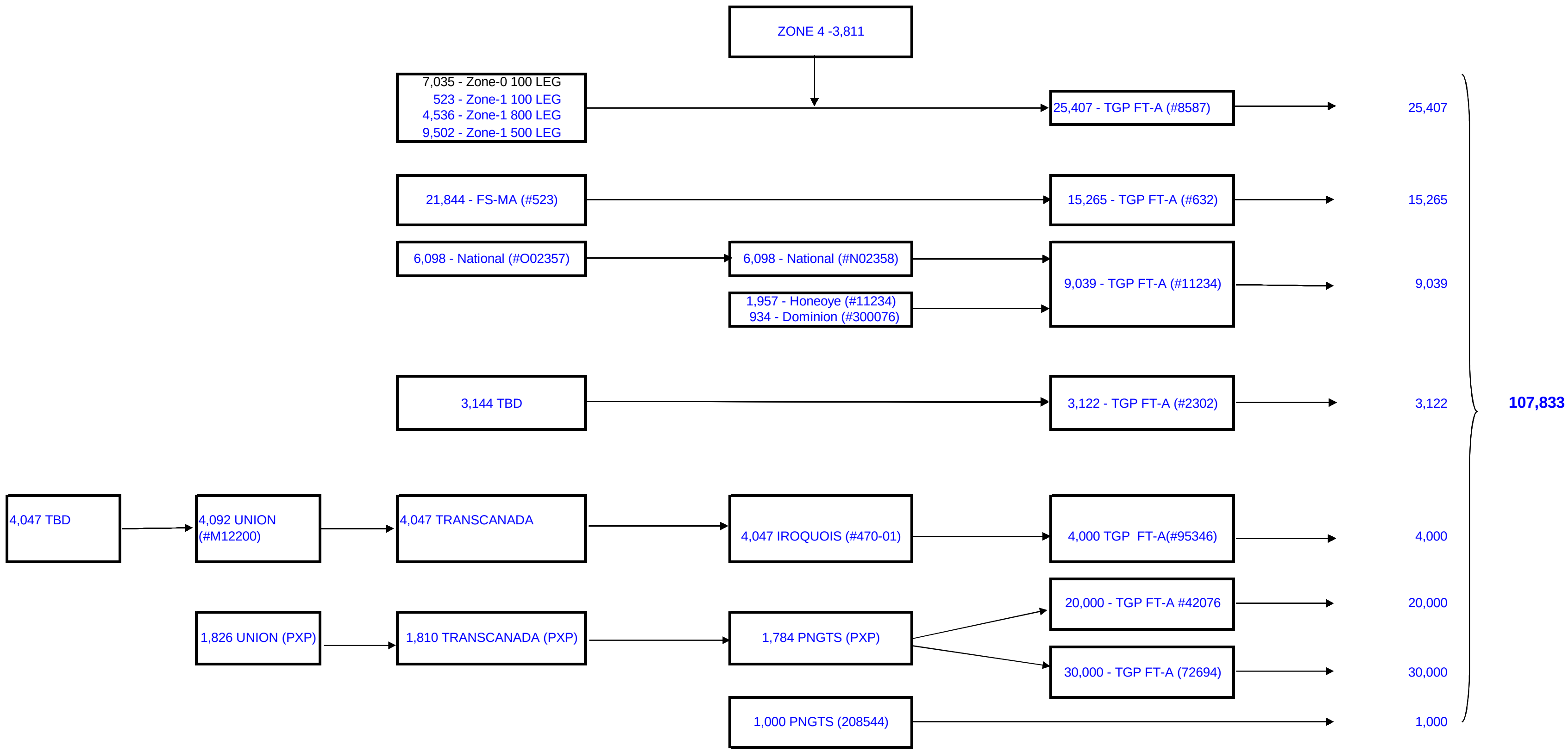
Please refer to the ENNGI 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Deborah Gilbertson
Sr. Manager, Energy Procurement

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

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



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

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Niagara	NA	NA	Supply	3,147	1,148,655	3/31/2019	N/A	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
ENGIE	FCS		Firm Combination Liquid and Vapor Svc	Up to 10 trucks	730,000	3/31/2019 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2019	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2019	N/A	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/A	
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2021	3/31/2019	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2020	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2022	11/1/2021	Evergreen Provision
Portland Natural Gas Transmission System	FT	208544	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	1,784	651,160	11/1/2019		Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2021	11/30/2020	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2020	10/31/2019	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2022	10/31/2021	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	1,810	660,650	11/1/2019		Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2022	10/31/2020	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	1,826	666,490	11/1/2019		Precedent Agreement

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

May 2017 - Apr 2018 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	17,503,533	44.21%	74.78%
G-42	12,021,109	30.36%	37.32%
G-43	2,980,868	7.53%	26.68%
G-51	2,767,315	6.99%	72.79%
G-52	2,732,036	6.90%	29.44%
G-53	1,147,046	2.90%	10.71%
G-54	437,495	1.11%	2.32%
Total C/I	39,589,403	100.00%	

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

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

Ln	Description	Reference	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**														
2	**Peak 2018 - 2019 Winter Cost of Gas Filing**														
3															
4	**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**														
5															
6	**Underground Storage Gas**														
7			May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		488,910	744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	488,910
10															
11	Injections (MMBtu)	Sch 11A ln 38 /10	261,143	221,871	271,295	250,468	250,468	250,468	226,287	-	-	-	-	-	1,731,999
12															
13	Subtotal		750,053	966,045	1,232,745	1,478,020	1,728,487	1,978,955	2,205,242	2,032,757	1,620,686	1,107,337	596,478	224,165	
14															
15	Storage Sale/Adjustments		(3,639)	(4,595)	(5,193)			-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 28 /10	(2,240)	-		-	-	-	(172,485)	(412,071)	(513,349)	(510,859)	(372,313)	(3,056)	(1,986,373)
18															
19	Ending Balance (MMBtu)		744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	221,109	234,536
20															
21															
22	Beginning Balance		$ 1,154,733	$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	1,154,733
23															
24	Injections	ln 11 * ln 36	$ 662,826	$ 532,338	$ 708,595	$ 674,472	$ 674,472	$ 674,472	$ 627,674	$ -	$ -	$ -	$ -	$ -	$ 4,554,849
25															
26	Subtotal		$ 1,817,559	$ 2,344,415	$ 3,049,262	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,696,861	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	
27															
28	Storage Sale/Adjustments		$ (28)	$ (3,747)	$ (3,491)			$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (5,454)		$ -	$ -	$ -	$ -	$ (445,586)	$ (1,064,513)	$ (1,326,148)	$ (1,319,717)	$ (961,805)	$ (7,894)	(5,131,118)
31															
32	Ending Balance		$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	$ 571,197	$ 578,464
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4232	$2.4268	$2.4736	$2.5170	$2.5425	$2.5615	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$2.5382	$2.3993	$2.6119	$2.6928	$2.6928	$2.6928	$2.7738	$2.8701	$2.9440	$2.9077	$2.8132	$2.6365	
37															
38	For Informational Purposes								Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
39	Summer Hedge Contracts - Vols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX								$2.9479	$3.0421	$3.1275	$3.0909	$2.9866	$2.6741	
42															
43	Hedged Volumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX								-	-	-	-	-	-	-
45	Hedge (Savings)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
46															
47	Month Dollar Average	ln (22 + ln 32) /2				$ 3,383,007	$ 4,057,479	$ 4,731,951	$ 5,160,231	$ 4,719,018	$ 3,523,688	$ 2,200,755	$ 1,059,994	$ 575,144	
48															
49	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%	
50															
51	Inventory Finance Charge	ln 47 * ln 49				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
52	Financial Expenses					0	0	0	0	0	0	0	0	0	
53	Total Inventory Finance Charges					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
54															
55															
38															

Ln			May-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
39															
40	**Liquid Propane Gas (LPG)**														
43	Beginning Balance		94,161	93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	94,161
45	Injections	Sch 11A ln 37 /10	-	-	42	-	-	-	-	-	35,622	9,133	-	-	44,797
47	Subtotal		94,161	93,982	93,945	93,945	93,945	93,945	93,945	93,945	129,567	52,741	43,608	43,608	
49	Withdrawals	Sch 11A ln 32 /10	(179)	(79)	-	-	-	-	-	-	(85,959)	(9,133)	-	-	(95,350)
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	43,608	43,608
56	Beginning Balance		$ 1,299,502	$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 1,299,502
58	Injections	ln 45 * ln 68	-	-	580	-	-	-	-	-	491,582	126,033	-	-	618,195
60	Subtotal		$ 1,299,502	$ 1,297,032	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,788,103	$ 727,852	$ 601,814	$ 601,814	
62	Withdrawals	ln 51 * ln 66	(2,470)	(1,090)	-	-	-	-	-	-	(1,186,284)	(126,038)	-	-	(1,315,883)
64	Ending Balance		$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 601,814	$ 601,814
66	Average Rate For Withdrawals		$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8006	$13.8005	$13.8005	$13.8005	
68	Propane Rate for Injections	Actual or Sch. 6, ln 158 * 10	$13.8009	$13.8009	$13.8009	$0.0000	$0.0000	$0.0000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 949,170	$ 601,817	$ 601,814	$ 601,814	
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-18	6,295,834	$0.0005	$ 3,273
Dec-18	7,906,710	0.0005	4,111
Jan-19	9,791,817	0.0005	5,091
Feb-19	10,106,599	0.0005	5,254
Mar-19	9,033,498	0.0005	4,696
Apr-19	7,609,960	0.0005	3,956
Total	**50,744,418**		**$ 26,381**

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

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)
1	**FOR THE MONTH OF:**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**30**	**31**	**31**	**28**
3	Beginning Balance	$ 2,215,339	$ 2,152,980	$ 2,092,394	$ 2,018,719	$ 1,907,454	$ 1,770,590	$ 1,557,222	$ 1,265,114
4									
5	Add Actual Costs	-	-	-	-	-	-	-	-
6									
7	Less Collected Revenue	(71,614)	(69,582)	(82,105)	(119,584)	(144,406)	(220,419)	(298,088)	(315,291)
8									
9	Add Administrative and Start Up Costs	-	-	-	-	-	-	-	-
10									
11	Ending Balance Pre-Interest	$ 2,143,725	$ 2,083,399	$ 2,010,289	$ 1,899,135	$ 1,763,048	$ 1,550,171	$ 1,259,134	$ 949,823
12									
13	Month's Average Balance	$ 2,179,532	$ 2,118,190	$ 2,051,341	$ 1,958,927	$ 1,835,251	$ 1,660,381	$ 1,408,178	$ 1,107,468
14									
15	Interest Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
16									
17	Interest Applied	$ 9 256	$ 8 995	$ 8 430	$ 8 319	$ 7 542	$ 7 051	$ 5 980	$ 4 248
18									
19	Ending Balance	**$ 2,152,980**	**$ 2,092,394**	**$ 2,018,719**	**$ 1,907,454**	**$ 1,770,590**	**$ 1,557,222**	**$ 1,265,114**	**$ 954,071**

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	
3	Beginning Balance	$ 954,071	$ 684,545	$ 483,022	$ 354,966	$ 275,250	$ 218,798	$ 163,706	$ 98,381	$ 9,733,120
4										
5	Add Actual Costs	-	-	-	-	-	-	-	-	-
6										
7	Less Collected Revenue	(272,886)	(203,997)	(129,775)	(81,051)	(57,499)	(55,876)	(65,880)	(95,294)	(1,940,462)
8										
9	Add Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-
10										
11	Ending Balance Pre-Interest	$ 681,185	$ 480,548	$ 353,247	$ 273,915	$ 217,751	$ 162,922	$ 97,826	$ 3,087	**$ 7,792,658**
12										
13	Month's Average Balance	$ 817,628	$ 582,547	$ 418,135	$ 314,440	$ 246,501	$ 190,860	$ 130,766	$ 50,734	
14										
15	Interest Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
16										
17	Interest Applied	$ 3 360	$ 2 474	$ 1 718	$ 1 335	$ 1 047	$ 784	$ 555	$ 208	**36,303**
18										
19	Ending Balance	**$ 684,545**	**$ 483,022**	**$ 354,966**	**$ 275,250**	**$ 218,798**	**$ 163,706**	**$ 98,381**	**$ 3,296**	

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
Lost Revenue Adjustment Mechanism

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

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

EnergyNorth Natural Gas Inc

2016 Customers (Equivalent Bills)

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

2016 Calendar BF Base Normal Revenue Adjusted

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

Base Revenue Per Customer

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

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

1/

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

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

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

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

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

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

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

Estimated Residential Conservation Charge
Effective November 1, 2018 - October 31, 2019

Beginning Balance	$	(1,532,842.79)
Program Budget Nov 18-Oct 19	$	4,182,242.33
Projected Interest	$	(61,190.00)
Projected Budget with Interest	$	2,588,209.55
Total Charges	$	2,588,209.55

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

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

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

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

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

Total 11/2018 - 10/2019

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

Environmental Surcharge - Manufactured Gas Plants

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

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NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- NHDES approved the Revised Phase II Work Plan for the site at the end of August 2000.

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

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

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

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

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

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

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

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June 2001.

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

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

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

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

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

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

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

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

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

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

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

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

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completed in October 2004 and the Remedial Completion Report, submitted to NHDES in January 2005, was subsequently approved.

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

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

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

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. DNAPL recovery is on-going. A Groundwater Management Permit was granted on June 5, 2014. A RAP Summary, involving the asphalt capping of the area over Holder #2 and continued groundwater monitoring, was submitted on April 2, 2015. A Monitoring Summary and Progress Report was submitted by ENGI on February 7, 2015. NHDES accepted the RAP Summary on April 10, 2015, with the provisions that ENGI submit the draft Activity and Use Restriction (AUR) and final engineering design plan for the cap by September 15, 2015. ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. NHDES responded to ENGI with their comments on December 15, 2016. Design for the engineered cap remedy is progressing, and when the design is completed it will be submitted to NHDES for approval. The cap construction and site paving are now planned for 2019 construction season.

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

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

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

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

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

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MANCHESTER FORMER MGP

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

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

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

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

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

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

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

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

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

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

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

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments. In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage. In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence. NHDES approved the ravine sign language in April 2002.

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

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

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

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

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

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers from April 2003 until the regular meetings ended on November 15, 2004. ENGI had

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attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided incurring costs associated with another entity's contamination.

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

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

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

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

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NO.

the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

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

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

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

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

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

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

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

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

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

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

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan (RAP) for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A RAP for the upland portion of the site was submitted to NHDES for review on June 30, 2010. NHDES issued its approval of the RAP for the upland portion of the site in a letter dated April 11, 2011. The Remedial Design Report summarizing the activities for addressing on-site and off-site impacts was submitted on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions. ENGI addressed these concerns and implemented the remedial activities on-site and off-site in 2017.

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

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

   Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier paid ENGI's attorneys fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States

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

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

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LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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

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

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

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

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NO.

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

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

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

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On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modelling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. In October 2010, NHDES issued a Preliminary Decision on RAP Addendum No. 2, in which NHDES indicated that it did not concur with ENGI's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. On January 28, 2011, ENGI submitted a comment letter to NHDES further explaining its rationale for the remedial alternative recommended in RAP Addendum No. 2. On November 2, 2011 NHDES announced a Final Decision indicating that it did not concur with ENGI's recommended remedial approach and selecting the full removal option as the remedy for the site. On December 2, 2011, ENGI filed an appeal of the NHDES Final Decision with the New Hampshire Waste Management Council. In March 2012, ENGI attended the Pre-Conference Hearing with the Council related to the appeal. Hearings on the matter were scheduled for October 18 and November 15, 2012. On July 26, 2012, the Hearing Officer granted an Assented to Motion to Continue the hearing until a date after January 3, 2013.

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

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

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

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

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

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

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

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

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

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LINE
NO.

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

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

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

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

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

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CONCORD FORMER MGP

LINE
NO.

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

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

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

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

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

   On July 15, 2003, NHDES issued a letter to ENGI requesting submission of a schedule and scope of work for a site investigation of the MGP site by mid-September 2003. ENGI proposed a May 2005 date for submission of a Site Investigation Report for the MGP site on Gas Street to NHDES by way of a letter dated October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

   ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will

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NO.

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

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling, along with further investigation of the brick tar sewer. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted in August 2013, in preparation for submittal of the Remedial Action Plan. This Supplement Data Collection Report was accepted by NHDES on October 24, 2013, and ENGI was authorized to prepare a RAP and Groundwater Management Permit (GMP) application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014.

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

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

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

Concord Pond: ENGI has continued to monitor groundwater semi-annually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003, 2007 and 2012, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the

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LINE
NO.

future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan (RAP) which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase.

The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location.

ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. Contact was reconvened with the City in 2013, and adjustments to the original design were made to address outfall maintenance and access concerns of the City and NHDOT, respectively. The design was presented to the City on January 26, 2016. A rigorous schedule toward construction in late summer 2017 was agreed to by ENGI and the City in February 2016. The City did not meet an early deadline to determine and communicate details regarding access to their storm water system. Communication was again resumed in July 2016 by the City, however the City remained unresponsive to ENGI on implementation of the joint remedial design.

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

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond. During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste

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

CONCORD FORMER MGP

LINE
NO.

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

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. Based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river. ENGI met with NHDES on February 20, 2013 to discuss all sampling activities to date, summarized in an SIR Addendum Report, submitted in June 2013.

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

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE:

Concord MGP: In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. The Supplemental Data Collection report summarizing the investigation activities was accepted in October 2013, authorizing ENGI to prepare a RAP and GMP Application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed RAP, and NHDES approved the RAP with conditions. A Remedial Design Report, summarizing pre-design investigations, is to be provided to NHDES by the end of 2015.

Concord Pond: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit

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

CONCORD FORMER MGP

LINE
NO.

was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI. ENGI met with these parties on several occasions in 2010 and 2011. The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. The design was adjusted to accommodate the City's desire to simplify maintenance of the storm water system, however ENGI has received no response from the City after numerous attempts to begin the implementation

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

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

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

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

2018 SUMMARY BY SITE

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

REDACTED

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

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

REDACTED

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

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

REDACTED

1450

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

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CLEAN HARBORS	1002010900					530.46	530.46			530.46
2	CLEAN HARBORS	1002009730					277.20	277.20			277.20
[redacted]											
4	GZA GEOENVIRONMENTAL INC	744589		26,730.07				26,730.07			26,730.07
5	PLANT INSPECTORS FOR REMEDIATION ACTIVITIES				3,753.43			3,753.43			3,753.43
6	ESMI OF NH	1015191			90,828.00			90,828.00			90,828.00
7	MARY CASEY - MILEAGE	JC8825					53.93	53.93			53.93
8	MARY CASEY - MILEAGE	JC8825					166.72	166.72			166.72
9	CLEAN HARBORS	1002057075					8,308.52	8,308.52			8,308.52
10	T FORD COMPANY, INC	1806-1			90,930.00			90,930.00			90,930.00
11	CLEAN HARBORS	1002064356					277.20	277.20			277.20
12	ESMI OF NH	1015242			2,590.08			2,590.08			2,590.08
13	CLEAN HARBORS	1002139193					2,204.40	2,204.40			2,204.40
14	GZA GEOENVIRONMENTAL INC	750011		48,029.02				48,029.02			48,029.02
15	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 0118					839.09	839.09			839.09
[redacted]											
18	GZA GEOENVIRONMENTAL INC	749333		17,521.62				17,521.62			17,521.62
19	ESMI OF NH	1015428			10,368.40			10,368.40			10,368.40
20	ESMI OF NH	1015617			3,030.10			3,030.10			3,030.10
21	GZA GEOENVIRONMENTAL INC	753031		28,062.90				28,062.90			28,062.90
22	ESMI OF NH	1015717			2,052.40			2,052.40			2,052.40
23	GZA GEOENVIRONMENTAL INC	749019		78,038.61				78,038.61			78,038.61
[redacted]											
25	GZA GEOENVIRONMENTAL INC	755534		11,812.55				11,812.55			11,812.55
26	MARY CASEY - MILEAGE	JC10420					31.23	31.23			31.23
27	GZA GEOENVIRONMENTAL INC	757697		6,629.13				6,629.13			6,629.13
[redacted]											
29	6/30/18 ACCRUAL			36,000.00				36,000.00			36,000.00
30	Environmental Staff Time						$ 1,659.75	1,659.75			1,659.75
	Total Pool Activity		**0.00**	**252,823.90**	**203,552.41**	**0.00**	**14,348.50**	**470,724.81**	**0.00**	**(124,681.32)**	**346,043.49**

REDACTED

161

1451

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	ALLEGRA MARKETING PRINT MAIL	31130					180.00	180.00			180.00
2	MARY CASEY - MILEAGE	JC8825					49.69	49.69			49.69
3	MARY CASEY - MILEAGE	LABOR					50.37	50.37			50.37
4								0.00			0.00
5								0.00			0.00
6	Environmental Staff Time						10,519.21	10,519.21			10,519.21
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**10,799.27**	**10,799.27**	**0.00**	**0.00**	**10,799.27**

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

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

REDACTED

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1453

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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Concord Pond

	(thru 9/99) pool #1 #3	(9/99 9/00) pool #4	(9/03 9/04) pool #5	(9/04 9/05) pool #6	(9/05 9/06) pool #7	(9/06 9/07) pool #8	(9/07 9/08) pool #9	(9/08 9/09) pool #10	(9/09 9/10) pool #11	(9/10 9/11) pool #12	(9/11 9/12) pool #13	(9/12 6/13) pool #14	(7/13 6/14) pool #15	(7/14 6/15) pool #16	(7/15 6/16) pool #17	(7/16 6/17) pool #18	DEF056 (7/17 6/18) pool #19	subtotal
1 Remediation costs (i.o. 500061)	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
Remediation costs (i.o. 500005)	-	-																-
A Subtotal - remediation costs	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
																		-
Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,204,671)
Cash recoveries (i.o. 500004)	(445,985)	-																(445,985)
Recovery costs (i.o. 500004)	623,784	-				-	-	-	-	-	-	-	-	-	-	-	-	623,784
Transfer Credit from Gas Restructuring																		-
B Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,026,872)
																		-
A-B Total net expenses to recover	3,583,912	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	216,743	81,238	59,069	32,324	78,235	34,590	88,148	127,356	5,051,537
																		-
																		-
Surcharge revenue:																		-
Act June 1998 - October 1998	(54,889)	-																(54,889)
Act November 1998 - October 1999	(538,143)	-																(538,143)
Act November 1999 - October 2000	(760,871)	-																(760,871)
Act November 2000 - October 2001	(626,614)	(13,925)																(640,539)
Act November 2001 - October 2002	(600,600)	(24,514)																(625,114)
Act November 2002 - October 2003	(592,678)	(15,197)																(607,874)
Act November 2003 - October 2004	(291,340)	(14,567)																(305,907)
Act November 2004- October 2005	(56,719)	(14,180)	(14,180)															(85,078)
Act November 2005- October 2006	-	(6,875)	(6,875)															(13,750)
Act November 2006- October 2007	-	-	-	-	(14,091)													(14,091)
Act November 2007- October 2008																		-
Act November 2012- October 2013										(5,002)	(5,002)							(10,003)
Act November 2013- October 2014										(12,749)	(12,749)							(25,497)
Act Nov 2009-Oct 2010 Base Rate Rev										($4,423)								(4,423)
Act Nov 2010-Oct 2011 Base Rate Rev										($32,310)								(32,310)
Act Nov 2011-Oct 2012 Base Rate Rev										($28,448)								(28,448)
Act Nov 2012-Oct 2013 Base Rate Rev										($2,143)	($2,143)							(4,286)
Act Nov 2013-Oct 2014 Base Rate Rev																		-
Act Nov 2014-Oct 2015 Base Rate Rev																		
AES collections			(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(220,792)
Gas Street overcollection	(23,511)																	(23,511)
Prior Period Pool under/overcollection	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	-	-	-	-	-	-	-	-	-	
																		0
																		-
C Surcharge Subtotal	(3,524,326)	(50,710)	(9,559)	39,108	34,729	104,437	234,166	(12,904)	(13,145)	(98,295)	(33,631)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(3,995,526)
D Net balance to be recovered (A-B+C)	59,586	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	47,629	47,608	45,345	18,376	64,062	20,185	73,484	112,498	1,056,012
E Allocation of Litigated Recovery			-		-		(329,540)	(102,675)	(123,791)	(47,228)	-	-	-	-	-	-	-	(603,234)
Surcharge calculation																		
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	6,801	12,956	7,875	36,607	14,417.84	62,986.49	112,498.35	254,142
remaining life	-	-	24	36	48	60	72	84	84	84	12	24	36	48	60	72	84	
one year	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
Required annual increase in rates:																		
smaller of D or F	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0003

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

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Laconia & Liberty Hill

			i.o. no. 500005 (thru 9/01) pool #1 #3	(9/04 9/05) pool #4	(9/05 9/06) pool #5	(9/06 9/07) pool #6	(9/07 9/08) pool #7 Incl. Audit Corr	(9/08 9/09) pool #8 Incl. Audit Corr	(9/09 9/10) pool #9	(9/10 9/11) pool #10	(9/11 9/12) pool #11	(9/12 6/13) pool #12	(7/13 6/14) pool #13	(7/14 6/15) pool #14	(7/15 6/16) pool #15	(7/16 6/17) pool #16	DEF086 (7/17 6/18) pool #17	subtotal
1	1	Remediation costs (i.o. 500061)	-	-									[redacted]					
2		Remediation costs (i.o. 500005)	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
3	A	Subtotal - remediation costs	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
5		Cash recoveries (i.o. 500061)	-	-	-	-	-	-										
6		Cash recoveries (i.o. 500004)	-	-	-	-	-	-										
7		Recovery costs (i.o. 500004)	-			11,643	21,729	-	-									
8		Transfer Credit from Gas Restructurin(				-	-	-										
9	B	Subtotal - net recoveries	-	-	-	11,643	21,729	-	-	-	-	-						
11	A-B	Total net expenses to recover	5,241,032	9,702	2,330,555	2,100,842	449,954	607,876	262,678	210,532	269,281	642,986						
14		Surcharge revenue:																
15	Act	June 1998 - October 1998	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
16	Act	November 1998 - October 1999	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
17	Act	November 1999 - October 2000	(151,933)	-	-		-	-	-	-	-	-	-	-	-	-	-	(151,933)
18	Act	November 2000 - October 2001	(696,237)	-	-		-	-	-	-	-	-	-	-	-	-	-	(696,237)
19	Act	November 2001 - October 2002	(796,714)	-	-		-	-	-	-	-	-	-	-	-	-	-	(796,714)
20	Act	November 2002 - October 2003	(805,434)	-	-		-	-	-	-	-	-	-	-	-	-	-	(805,434)
21	Act	November 2003 - October 2004	(699,215)															(699,215)
22	Act	November 2004- October 2005	(652,264)															(652,264)
23	Act	November 2005- October 2006	(691,159)	-	-		-	-	-	-	-	-	-	-	-	-	-	(691,159)
24	Act	November 2006- October 2007	(648,174)	-	(309,996)													(958,171)
25	Act	November 2007- October 2008																-
26	Act	November 2012- October 2013									(20,006)							(20,006)
27	Act	November 2013- October 2014									(25,497)	(76,491)						(101,988)
28	Act	Nov 2009-Oct 2010 Base Rate Rev								($4,296)								(4,296)
29	Act	Nov 2010-Oct 2011 Base Rate Rev								($31,384)								(31,384)
30	Act	Nov 2011-Oct 2012 Base Rate Rev								($27,632)								(27,632)
31	Act	Nov 2012-Oct 2013 Base Rate Rev								$0	($14,208)							(14,208)
32	Act	Nov 2013-Oct 2014 Base Rate Rev									(28,433)	(28,433)	(28,433)					(85,298)
33	Act	Nov 2014-Oct 2015 Base Rate Rev									(21,909)	(21,909)	(21,909)	(21,909)	-	-	-	(87,637)
34		AES collections																-
35		Gas Street overcollection																-
36		Prior Period Pool under/overcollection	21,391	111,336	121,038	2,141,596	4,242,438		-	-	(89,606)	-	-	-	-	-	-	
39	C	Surcharge Subtotal	(5,119,739)	111,336	(188,958)	2,141,596	4,242,438	-	-	(63,313)	(199,659)	(126,833)	(50,342)	(21,909)	-	-	-	(5,823,577)
42	D	Net balance to be recovered (A-B+C)	121,293	121,038	2,141,596	4,242,438	4,692,393	607,876	262,678	147,219	69,622	516,153	[redacted]					
44	E	Allocation of Litigated Recovery					(4,692,393)	(607,876)	(262,678)	(236,825)	-	-						
46		Surcharge calculation																
47		Unrecovered costs (D+E)	-	-			-	-	-	-	9,946	147,472.25						
48		remaining life	-	36	48	60	72	84	84	48	12	24						
49		one year	-	12	12	12	12	12	12	12	12	12						
50	F	amortization	-	-	-	-	-	-	-	-	9,946	73,736						
52		Required annual increase in rates:																
53		smaller of D or F	-	-	-		-	-	-	-	9,946	73,736	[redacted]					
55		forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0004	[redacted]					

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

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Manchester

DEF057

	(9/00 9/03) pool #1 #3	(9/03 9/04) pool #4	(9/04 9/05) pool #5	(9/05 9/06) pool #6	(9/06 9/07) pool #7	(9/07 9/08) pool #8	(9/08 9/09) pool #9	(9/09 9/10) pool #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	(7/17 6/18) pool #18	subtotal
						Incl. Audit Corr											
1 Remediation costs (i.o. 500061)	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	10,598,402
Remediation costs (i.o. 500005)	825,092																825,092
A Subtotal - remediation costs	825,092	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	11,423,494
Cash recoveries (i.o. 500061)	-			(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(2,753,952)
Cash recoveries (i.o. 500004)	-																-
Recovery costs (i.o. 500004)	-	1,242,326			2,546	-											1,244,872
Transfer Credit from Gas Restructuring					-	-											-
B Subtotal - net recoveries	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(1,509,080)
A-B Total net expenses to recover	825,092	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,589	442,298	(188,619)	61,210	75,440	22,690	50,523	346,043	9,914,414
																	-
																	-
Surcharge revenue:																	-
Act June 1998 - October 1998	-	-															-
Act November 1998 - October 1999	-	-															-
Act November 1999 - October 2000	-	-															-
Act November 2000 - October 2001	-	-															-
Act November 2001 - October 2002	(73,543)	-															(73,543)
Act November 2002 - October 2003	(75,984)	-															(75,984)
Act November 2003 - October 2004	(138,576)	-															(138,576)
Act November 2004- October 2005	(113,437)	(212,695)	-			-	-	-	-	-	-	-	-	-	-	-	(326,132)
Act November 2005- October 2006	(96,247)	(206,243)	(261,242)			-	-	-	-	-	-	-	-	-	-	-	(563,732)
Act November 2006- October 2007	(126,817)	(211,361)	(281,815)	(42,272)													(662,265)
Act November 2007- October 2008																	-
Act November 2012- October 2013										(40,012)							(40,012)
Act November 2013- October 2014										(50,994)							(50,994)
Act Nov 2009-Oct 2010 Base Rate Rev									-								-
Act Nov 2010-Oct 2011 Base Rate Rev									-								-
Act Nov 2011-Oct 2012 Base Rate Rev									-								-
Act Nov 2012-Oct 2013 Base Rate Rev									-	(23,337)							(23,337)
Act Nov 2013-Oct 2014 Base Rate Rev																	-
Act Nov 2014-Oct 2015 Base Rate Rev																	
AES collections																	-
Gas Street overcollection																	-
Prior Period Pool under/overcollection	394,600	276,881	1,224,246	2,671,037	2,958,927	3,302,330	-	-	-								
C Surcharge Subtotal	(230,004)	(353,418)	681,189	2,628,765	2,958,927	3,302,330	-	-	-	(114,343)	-	-	-	-	-	-	(1,954,576)
D Net balance to be recovered (A-B+C)	595,088	1,224,246	2,671,037	2,958,927	3,302,330	6,562,539	312,185	328,678	137,589	327,955	(188,619)	61,210	75,440	22,690	50,523	346,043	7,959,838
E Allocation of Litigated Recovery		-	-			(6,562,539)	(312,185)	(328,678)	(91,770)	-	-	-	-	-	-	-	(7,295,172)
Surcharge calculation																	
Unrecovered costs (D+E)	-	-	-	-		-	-	-	-	46,851	(53,891)	26,233	43,108	16,207	43,305	346,043	467,856
remaining life	-	24	36	48	60	70	84	84	12	12	24	36	48	60	72	84	
one year	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	46 851	(26 946)	8 744	10 777	3 241	7 218	49 435	
Required annual increase in rates:																	
smaller of D or F	-	-	-	-		-	-	-	-	46,851	(26,946)	8,744	10,777	3,241	7,218	49,435	99,320
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003	$0.0005

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		Nashua																
						Corrected per 2/08 Audit											DEF054	
		(9/00 9/03) pool #1 #3	(9/03 9/04) pool #4	(9/04 9/05) pool #5	(9/05 9/06) pool #6	(9/06 9/07) pool #7	(9/07 9/08) pool #8	(9/08 9/09) pool #9	(9/09 9/10) pool #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	(7/17 6/18) pool #18	subtotal
1	1 Remediation costs (i.o. 500061)	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	1,620,044
2	Remediation costs (i.o. 500005)	1,771,567																1,771,567
3	A Subtotal - remediation costs	1,771,567	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	3,391,611
4																		-
5	Cash recoveries (i.o. 500061)	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(566,063)
6	Cash recoveries (i.o. 500004)	-																-
7	Recovery costs (i.o. 500004)	-			5,449	12,938	-	-										18,388
8	Transfer Credit from Gas Restructuring					-	-	-										-
9	B Subtotal - net recoveries	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(547,675)
10																		-
11	A-B Total net expenses to recover	1,771,567	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,351	396,411	(80,241)	35,950	65,217	62,435	85,314	15,523	2,843,936
12																		
13																		
14	Surcharge revenue:																	
15	Act June 1998 - October 1998	-	-															-
16	Act November 1998 - October 1999	-	-															-
17	Act November 1999 - October 2000	-	-															-
18	Act November 2000 - October 2001	-	-															-
19	Act November 2001 - October 2002	(183,857)	-															(183,857)
20	Act November 2002 - October 2003	(243,150)	-															(243,150)
21	Act November 2003 - October 2004	(247,639)	-															(247,639)
22	Act November 2004- October 2005	(241,054)	-															(241,054)
23	Act November 2005- October 2006	(247,492)	-	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(274,991)
24	Act November 2006- October 2007	(253,633)	-	(28,181)	-													(281,815)
25	Act November 2007- October 2008																	-
26	Act November 2012- October 2013										(40,012)							(40,012)
27	Act November 2013- October 2014										(38,246)							(38,246)
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									-	(20,916)							(20,916)
32	Act Nov 2013-Oct 2014 Base Rate Rev																	-
33	Act Nov 2014-Oct 2015 Base Rate Rev																	
34	AES collections																	-
35	Gas Street overcollection																	-
36	Prior Period Pool under/overcollection	669,664	543,205	554,046	704,732	714,955	733,479	-	-	-	6,224	-	-	-	-	-	-	
37																		
38																		
39	C Surcharge Subtotal	(747,161)	543,205	498,365	704,732	714,955	733,479	-	-	-	(92,950)	-	-	-	-	-	-	(1,571,680)
40																		
41																		
42	D Net balance to be recovered (A-B+C)	1,024,405	554,046	704,732	714,955	733,479	830,669	16,289	98,975	33,351	303,461	(80,241)	35,950	65,217	62,435	85,314	15,523	1,272,256
43																		
44	E Allocation of Litigated Recovery	-	-	-	-	-	(830,669)	(16,289)	(98,975)	(27,127)	-	-	-	-	-	-	-	(973,061)
45																		
46	Surcharge calculation																	
47	Unrecovered costs (D+E)	-	-	-	-		-	-	-		43,352	(22,926)	15,407	37,267	44,596	73,126	15,523	206,345
48	remaining life	12	24	36	48	60	72	84	84	72	12	24	36	48	60	72	84	
49	one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	-	-	-	-	-	-	-	-	-	43 352	(11 463)	5 136	9 317	8 919	12 188	2 218	
51																		
52	Required annual increase in rates:																	
53	smaller of D or F	-	-	-	-		-	-	-	-	43,352	(11,463)	5,136	9,317	8,919	12,188	2,218	69,665
54																		
55	forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																		
57	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0004

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Dover												
												DEF059	
	(9/02 9/03) pool #1	(9/04 9/05) pool #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/17 6/18) pool #12	subtotal
1 Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	-	-	-	-	-	-	21,142
Remediation costs (i.o. 500005)	181,066												181,066
A Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	-	-	-	-	-	-	202,208
Cash recoveries (i.o. 500061)	-					-	-	-	-	-	-	-	-
Cash recoveries (i.o. 500004)	-												-
Recovery costs (i.o. 500004)	-												-
Transfer Credit from Gas Restructuring													-
B Subtotal - net recoveries	-	-	-	-	-	-	-	-	-	-	-	-	-
A-B Total net expenses to recover	181,066	18,854	2,288	-	-	-	-	-	-	-	-	-	202,208
Surcharge revenue:													
Act June 1998 - October 1998	-												-
Act November 1998 - October 1999	-												-
Act November 1999 - October 2000	-												-
Act November 2000 - October 2001	-												-
Act November 2001 - October 2002	-												-
Act November 2002 - October 2003	-												-
Act November 2003 - October 2004	(29,134)												(29,134)
Act November 2004- October 2005	(28,359)												(28,359)
Act November 2005- October 2006	(27,499)	-			-	-	-	-	-	-	-	-	(27,499)
Act November 2006- October 2007	(28,181)	-	-										(28,181)
Act November 2007- October 2008													-
Act November 2012- October 2013													-
Act November 2013- October 2014													-
Act Nov 2009-Oct 2010 Base Rate Rev													-
Act Nov 2010-Oct 2011 Base Rate Rev													-
Act Nov 2011-Oct 2012 Base Rate Rev													-
Act Nov 2012-Oct 2013 Base Rate Rev													-
Act Nov 2013-Oct 2014 Base Rate Rev													-
Act Nov 2014-Oct 2015 Base Rate Rev													
AES collections													-
Gas Street overcollection													-
Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-	-	-	-	-	-	-	
C Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	-	-	-	-	-	-	(113,174)
D Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	-	-	-	-	-	-	89,034
E Allocation of Litigated Recovery		-		-	(89,034)	-	-	-	-	-	-	-	(89,034)
Surcharge calculation													
Unrecovered costs (D+E)	-	-	-		-	-	-	-	-	-	-	-	-
remaining life	24	36	48	60	72	84	84	84	84	84	84	84	
one year	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	-	-	-	
Required annual increase in rates:													
smaller of D or F	-	-	-		-	-	-	-	-	-	-	-	-
forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	Keene												
												DEF055	
	(9/03 9/04) pool #1	(9/04 9/05) pool #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	subtotal
1 Remediation costs (i.o. 500061)	-										[redacted]		
Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
A Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
Cash recoveries (i.o. 500061)	-												
Cash recoveries (i.o. 500004)	-												
Recovery costs (i.o. 500004)			18,831	823	-	-	-	-					
Transfer Credit from Gas Restructuring				-	-	-							
B Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-			
A-B Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400			
													-
													-
Surcharge revenue:													-
Act June 1998 - October 1998	-												-
Act November 1998 - October 1999	-												-
Act November 1999 - October 2000	-												-
Act November 2000 - October 2001	-												-
Act November 2001 - October 2002	-												-
Act November 2002 - October 2003	-												-
Act November 2003 - October 2004	-												-
Act November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
Act November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
Act November 2006- October 2007	-	-	(14,091)										(14,091)
Act November 2007- October 2008													-
Act November 2012- October 2013													-
Act November 2013- October 2014													-
Act Nov 2009-Oct 2010 Base Rate Rev													-
Act Nov 2010-Oct 2011 Base Rate Rev													-
Act Nov 2011-Oct 2012 Base Rate Rev													-
Act Nov 2012-Oct 2013 Base Rate Rev													-
Act Nov 2013-Oct 2014 Base Rate Rev													-
Act Nov 2014-Oct 2015 Base Rate Rev													
AES collections													-
Gas Street overcollection													-
Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	-	-	-	-	
C Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	-	-	-	-	(14,091)
D Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	488	1,400	[redacted]		
E Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-			
Surcharge calculation													
Unrecovered costs (D+E)	-	-	-			-	-	-	70	400			
remaining life	24	36	48	60	72	84	84	84	12	24			
one year	12	12	12	12	12	12	12	12	12	12			
F amortization	-	-	-	-	-	-	-	-	70	200			
Required annual increase in rates:													
smaller of D or F	-	-	-			-	-	-	70	200	[redacted]		
forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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			Concord													
				Corrected per 1/24/07 Audit	Corrected per 2/08 Audit										DEF077	
			(9/03 9/05) pool #1 & #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	(7/15 6/16) pool #13	(7/16 6/17) pool #14	(7/17 6/18) pool #15	subtotal
1	1	Remediation costs (i.o. 500061)	-												[redacted]		
2		Remediation costs (i.o. 500005)	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749			
3	A	Subtotal - remediation costs	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749			
4																	
5		Cash recoveries (i.o. 500061)	-	(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)			
6		Cash recoveries (i.o. 500004)	-														
7		Recovery costs (i.o. 500004)				1,432	(1,007)										
8		Transfer Credit from Gas Restructuring		-													
9	B	Subtotal - net recoveries	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)			
10																	
11	A-B	Total net expenses to recover	243,123	22,106	61,665	(3,163)	92,679	46,190	168,338	257,528	45,384	123,355	163,783	95,553			
12																	-
13																	-
14		Surcharge revenue:															-
15		Act June 1998 - October 1998	-														-
16		Act November 1998 - October 1999	-														-
17		Act November 1999 - October 2000	-														-
18		Act November 2000 - October 2001	-														-
19		Act November 2001 - October 2002	-														-
20		Act November 2002 - October 2003	-														-
21		Act November 2003 - October 2004	-														-
22		Act November 2004- October 2005															-
23		Act November 2005- October 2006	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(27,499)
24		Act November 2006- October 2007	(28,181)	-													(28,181)
25		Act November 2007- October 2008															-
26		Act November 2012- October 2013							(20,006)	(20,006)							(40,012)
27		Act November 2013- October 2014							(12,749)	(25,497)							(38,246)
28		Act Nov 2009-Oct 2010 Base Rate Rev							($1,891)								(1,891)
29		Act Nov 2010-Oct 2011 Base Rate Rev							($13,816)								(13,816)
30		Act Nov 2011-Oct 2012 Base Rate Rev							($12,164)								(12,164)
31		Act Nov 2012-Oct 2013 Base Rate Rev							($6,794)	($6,794)							(13,588)
32		Act Nov 2013-Oct 2014 Base Rate Rev															-
33		Act Nov 2014-Oct 2015 Base Rate Rev															
34		AES collections															-
35		Gas Street overcollection															-
36		Prior Period Pool under/overcollection	22,191	187,442	209,549	271,214	-	-	-	-	-	-	-	-	-	-	
37																	
38																	
39	C	Surcharge Subtotal	(33,490)	187,442	209,549	271,214	-	-	(67,420)	(52,297)	-	-	-	-	-	-	(175,398)
40																	
41																	
42	D	Net balance to be recovered (A-B+C)	209,633	209,549	271,214	268,051	92,679	46,190	100,919	205,231	45,384	123,355	163,783	95,553	[redacted]		
43																	
44	E	Allocation of Litigated Recovery	-	-	-	(268,051)	(92,679)	(46,190)	(13,905)	-	-	-	-	-			
45																	
46		Surcharge calculation															
47		Unrecovered costs (D+E)	-	-		-	-	-	-	29,319	12,967	52,866	93,590	68,252			
48		remaining life	84	60		72	84	84	12	12	24	36	48	60			
49		one year	24	12		12	12	12	12	12	12	12	12	12			
50	F	amortization	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650			
51																	
52		Required annual increase in rates:															
53		smaller of D or F	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650	[redacted]		
54																	
55		forecasted therm sales	369,309,748	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																	
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0001	$0.0001	$0.0001	[redacted]		

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	General																
		Corrected per 1/24/07 Audit												DEF064			**2018** **MGP** **Remediation**
	(9/02 9/05) **pool #1 #3**	**(9/05 9/06)** **pool #4**	**(9/06 9/07)** **pool #5**	**(9/07 9/08)** **pool #6**	**(9/08 9/09)** **pool #7**	**(9/09 9/10)** **pool #8**	**(9/10 9/11)** **pool #9**	**(9/11 9/12)** **pool #10**	**(9/12 6/13)** **pool #11**	**(7/13 6/14)** **pool #12**	**(7/14 6/15)** **pool #13**	**(7/15 6/16)** **pool #14**	**(7/16 6/17)** **pool #15**	**(7/17 6/18)** **pool #16**	**subtotal**		**subtotal**
1 Remediation costs (i.o. 500061)	-														-		[redacted]
Remediation costs (i.o. 500005)	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
A Subtotal - remediation costs	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
Cash recoveries (i.o. 500061)	-		-	-	-										-		
Cash recoveries (i.o. 500004)	-														-		
Recovery costs (i.o. 500004)		290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	322,270		
Transfer Credit from Gas Restructuring	(3,331)	-													(3,331)		
B Subtotal - net recoveries	(3,331)	290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	318,939		
A-B Total net expenses to recover	746,908	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	73,846	13,139	(7,638)	11,879	6,547	10,799	1,218,366		
																	-
Surcharge revenue:																	
Act June 1998 - October 1998	-														-		(54,889)
Act November 1998 - October 1999	-														-		(538,143)
Act November 1999 - October 2000	-														-		(912,804)
Act November 2000 - October 2001	-														-		(1,336,776)
Act November 2001 - October 2002	-														-		(1,679,228)
Act November 2002 - October 2003	-														-		(1,732,442)
Act November 2003 - October 2004	(8,265)														(8,265)		(1,428,735)
Act November 2004- October 2005	(70,898)														(70,898)		(1,403,787)
Act November 2005- October 2006	(96,247)			-	-	-	-	-	-	-	-	-	-	-	(96,247)		(1,694,877)
Act November 2006- October 2007		(49,318)													(49,318)		(2,036,113)
Act November 2007- October 2008															-		-
Act November 2012- October 2013							(5,002)	(5,002)							(10,003)		(160,048)
Act November 2013- October 2014							(12,749)	(12,749)	(12,749)						(38,246)		(293,217)
Act Nov 2009-Oct 2010 Base Rate Rev															-		(10,611)
Act Nov 2010-Oct 2011 Base Rate Rev															-		(77,509)
Act Nov 2011-Oct 2012 Base Rate Rev															-		(68,244)
Act Nov 2012-Oct 2013 Base Rate Rev															-		(76,335)
Act Nov 2013-Oct 2014 Base Rate Rev																	(85,298)
Act Nov 2014-Oct 2015 Base Rate Rev																	(87,637)
AES collections	-														-		(220,792)
Gas Street overcollection															-		(23,511)
Prior Period Pool under/overcollection	296,594	457,429	732,622	786,465	-	-	-	-	-	-	-	-	-	-			
C Surcharge Subtotal	15,503	408,111	732,622	786,465	-	-	(17,750)	(17,750)	(12,749)	-	-	-	-	-	(272,977)		(13,920,997)
D Net balance to be recovered (A-B+C)	762,410	732,622	786,465	621,477	(2,931)	4,199	51,536	61,217	61,098	13,139	(7,638)	11,879	6,547	10,799	945,390	3,595,226	[redacted]
																-	
E Allocation of Litigated Recovery	-	-	-	(621,477)	2,931	(4,199)	(11,582)	-	-	-	-	-	-	-	(634,326)	(428,437)	
																-	
Surcharge calculation																-	
Unrecovered costs (D+E)	-	-		-	-	-	-	8,745	17,456	5,631	(4,364)	8,485	5,611	10,799	52,364	2,150,415	
remaining life	84	60	72	84	84	84	12	12	24	36	48	60	72	84			
one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12			
F amortization	-	-	-	-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543			
Required annual increase in rates:																	
smaller of D or F	-	-		-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543	22,434	584,652	
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874		**184,654,874**
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001		**$0.0161**

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

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

	(thru 9/98)	(9/99 9/00)	(9/00 9/01)	(9/01 9/02)	(9/02 9/03)	(9/03 9/04)	(9/04 9/05)	(9/05 9/06)	(9/06 9/07)	(9/07 9/08)	(9/08 9/09)	(9/09 9/10)	(9/10 9/11)	(9/11 9/12)	(7/13 6/14)	(7/14 6/15)	(7/15 6/16)	(7/16 6/17)	(7/17 6/18)	Total
1 Remediation costs (i.o. 500061)	5,420,852	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,515	993,434	196,611	312,039	220,344	256,871	670,904	[redacted]
Remediation costs (i.o. 500005)	1,027,747	-	-	-	181,066	10,165	16,308	2,444,366	2,229,625	255,263	658,324	316,280	459,550	651,906	1,801,404	7,975,914	3,307,910	260,380	115,841	[redacted]
A Subtotal - remediation costs	6,448,599	129,002	-	-	181,066	416,637	2,252,990	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,146,065	1,645,340	1,998,015	8,287,953	3,528,254	517,250	786,745	[redacted]
Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(79,446)	(121,889)	(119,826)	(53,116)	(195,423)	[redacted]
Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	-	-	[redacted]
Recovery costs (i.o. 500004)	623,784	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	(14,068)	2,500,000	2,475,750	-	-	-	[redacted]
Transfer Credit from Gas Restructurin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]
B Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	-	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	2,420,554	2,353,861	(119,826)	(53,116)	(195,423)	[redacted]
A-B Total net expenses to recover	4,611,659	95,798	-	-	181,066	1,273,932	2,379,412	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	835,839	1,526,211	4,418,569.29	10,641,813.86	3,408,427.63	464,499.00	591,686.20	[redacted]
Surcharge revenue:																				
Act June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act November 2000 - October 2001	(779,786)	(13,925)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(793,711)
Act November 2001 - October 2002	(759,943)	(24,514)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(784,457)
Act November 2002 - October 2003	(744,646)	(15,197)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(759,843)
Act November 2003 - October 2004	(422,442)	(14,567)	-	-	(29,134)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(466,143)
Act November 2004- October 2005	(184,336)	(14,180)	-	-	(28,359)	(226,875)	-	-	-	-	-	-	-	-	-	-	-	-	-	(453,749)
Act November 2005- October 2006	(141,176)	(6,875)	-	-	(27,499)	(213,118)	(288,741)	-	-	-	-	-	-	-	-	-	-	-	-	(677,409)
Act November 2006- October 2007	-	-	-	-	(28,181)	(211,361)	(309,996)	(429,768)	-	-	-	-	-	-	-	-	-	-	-	(979,307)
Act November 2007- October 2008													-	-	-	-	-	-	-	-
Act November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	-	-	(160,048)
Act November 2013- October 2014													(38,246)	(165,731)	-	-	-	-	-	(203,977)
Act Nov 2009-Oct 2010 Base Rate Rev													(10,611)	-	-	-	-	-	-	(10,611)
Act Nov 2010-Oct 2011 Base Rate Rev													(77,509)	-	-	-	-	-	-	(77,509)
Act Nov 2011-Oct 2012 Base Rate Rev													(68,244)	-	-	-	-	-	-	(68,244)
Act Nov 2012-Oct 2013 Base Rate Rev													(8,937)	(67,398)	-	-	-	-	-	(76,335)
Act Nov 2013-Oct 2014 Base Rate Rev													-	(28,433)	(28,433)	-	-	-	-	(56,865)
Act Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	(21,909)	(21,909)	-	-	-	(65,728)
AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(207,067)
Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
Prior Period Pool under/overcollection																				
C Surcharge Subtotal	(4,561,677)	(89,257)	-	-	(113,174)	(684,947)	(610,364)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(246,777)	(427,248)	(64,290)	(36,082)	(14,405)	(14,664)	(14,858)	(7,370,353)
D Net balance to be recovered (A-B+C)	49,982	6,541	-	-	67,892	588,985	1,769,048	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	589,062	1,098,962	4,354,279	10,605,732	3,394,023	449,835	576,828	[redacted]
E Allocation of Litigated Recovery																				
Surcharge calculation																				
Unrecovered costs (D+E)																				
remaining life																				
one year																				
F amortization																				
Required annual increase in rates:																				
smaller of D or F																				
forecasted therm sales																				
surcharge per therm																				

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019

Rate: $0.19 /MMBtu

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Monthly Imbalances

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

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

Schedule 21
2018 - 2019 Winter Cost of Gas Filing
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Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

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

Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		164,571	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 95346	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6) 72694	30,000		
10			79,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3 of 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		56,738	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,969,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$0		Attachment B Page 3 Line 1
27	Total		$6,949,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$122.48		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$20.41**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

Tennessee Allocations

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

Capacity Resources effective November 1, 2017

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

* All gas transferred for storage contracts will be based on LDC's monthly WACOG
**All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention   Demand charge applicable for 6 months

Note **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/18. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the EnergyNorth Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $18.2633 /dth.

REDACTED
Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

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

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

REDACTED

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	**Storage**	**Peaking**	**Total**
G-41	**LAHW**	Low Annual C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	59.0%	13.6%	27.4%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	59.0%	13.6%	27.4%	100.0%

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

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

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

Allocate Class Design Day Throughput to Supply Sources

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

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

% of Peak Day Requirement

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Design DD 71.386

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

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

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

Allocate Design Day Sendout to Rate Classes

	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	19%	0.307%	109	469	578
R-3 RSH	6%	44.317%	4,189	67,700	71,889
G-41 SL	3%	19.271%	1,045	29,440	30,485
G-51 SH	26%	1.235%	670	1,886	2,556
G-42 ML	4%	23.728%	1,566	36,248	37,813
G-52 MH	34%	2.314%	1,846	3,535	5,381
G-43 LL	8%	4.504%	587	6,881	7,468
G-53 LLL90	36%	1.624%	1,412	2,480	3,893
G-54 LLG90	9%	2.701%	382	4,126	4,507
TOTAL		100.000%	11,806	152,765	164,571

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

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

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	R-1 RNSH	1	3	6	7	6	5	3	2	0	0	0	1	33
LLF	R-3 RSH	193	559	1,003	1,010	809	655	338	92	0	0	0	31	4,683
LLF	G-41 SL	73	231	454	460	352	277	138	31	0	0	0	6	2,017
HLF	G-51 SH	6	15	26	28	23	18	15	12	0	0	2	5	149
LLF	G-42 ML	122	310	532	549	433	340	186	62	0	0	7	34	2,575
HLF	G-52 MH	19	31	51	57	42	33	19	25	0	0	1	17	295
LLF	G-43 LL	12	41	104	127	82	64	54	14	0	0	0	6	499
HLF	G-53 LLL90	10	15	30	54	30	24	23	17	0	0	4	16	223
HLF	G-54 LLL110	0	0	13	32	12	0	22	105	0	0	0	26	187
HLF	G-63 LLG110	0	0	21	63	37	0	0	0	0	0	0	0	121
	TOTAL	406	1,175	2,209	2,360	1,794	1,385	765	330	(31)	(31)	(16)	109	10,768
	HLF	36	65	147	242	149	80	81	161	0	0	7	64	1,008
	LLF	400	1,142	2,093	2,146	1,676	1,335	715	199	0	0	7	76	9,775
	Actual BDD	**472.5**	**982.5**	**1219.5**	**1028.5**	**858.0**	**730.5**	**339.0**	**83.0**	**33.0**	**14.0**	**38.5**	**136.5**	5935 5

Heat Factors

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

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

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

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

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

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

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

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6.0%				$0.3927	$0.3722	$ 943.37	$ 926 93	$ 16.44	1.77%	$0 3927	$0.3736	$ 1,570 86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9.0%				$0.4724	$0.4628	$ 679.85	$ 672 22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161 81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20.0%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10 90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10 22%
4	Nov 01 - Apr 02	24.0%				$0.5141	$0.4818	$ 790.65	$ 760 55	$ 30.10	3 96%	$0 5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3 52%
5	Nov 02 - Apr 03	24.0%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2 27%	$0 5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28 84)	-2.10%
6	Nov 03 - Apr 04	23.0%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3 25%	$0 8759	$0.8352	$ 1,798 38	$ 1,740.30	$ 58.08	3 34%
7	Nov 04 - Apr 05	29.6%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189 55	$ (46.60)	-3 92%	$0 9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3 51%
8	Nov 05 - Apr 06	29.8%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10 90%	$1 3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214 89	9.61%
9	Nov 06 - Apr 07	15.1%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415 80	$ 93.99	6.64%	$1 2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	15.8%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 27.69	1 97%	$1 2044	$1.1725	$ 2,232 39	$ 2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15.2%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$ 1,555.31	$ 1,373 85	$ 181.46	13 21%	$1 2836	$1.0958	$ 2,467.49	$ 2,199.54	$ 267 95	12.18%
12	Nov 09 - Apr 10	11.4%	$0.0200	8,405,413	$ 168,108	$0.9863	$0.9416	$ 1,250.80	$ 1,209.12	$ 41.69	3.45%	$0 9865	$0.9408	$ 1,984 29	$ 1,919.03	$ 65 26	3.40%
13	Nov 10 - Apr 11	12.6%	$0.0200	10,379,804	$ 207,596	$0.8420	$0.8029	$ 1,175.03	$ 1,138 58	$ 36.45	3 20%	$0 8434	$0.8030	$ 1,880 96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	11.9%	$0.0200	7,835,197	$ 156,704	$0.8126	$0.7309	$ 1,165.61	$ 1,089.44	$ 76.17	6 99%	$0 8129	$0.7327	$ 1,845 28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	10.9%	$0.0200	8,179,524	$ 163,590	$0.6919	$0.7680	$ 743.03	$ 792.48	$ (49.45)	-6 24%	$0.6936	$0.7724	$ 1,989 86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	10.5%	$0.0200	8,930,779	$ 178,616	$0.9095	$1.1011	$ 857.72	$ 981 21	$ (123.49)	-12 59%	$0 9108	$1.1057	$ 2,736 57	$ 3,117.48	$ (380 92)	-12 22%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.7321	$ 1,127.66	$ 948.07	$ 179.59	18 94%	$0.6312	$0.7403	$ 2,422.09	$ 2,635.27	$ (213.18)	-8.09%
18	Nov 15 - Apr 16	15.3%	$0.0200	4,941,157	$ 98,823	$0.7716	$0.7516	$ 869.15	$ 712.73	$ 156.42	21 95%						
19	Nov 16 - Apr 17	11.5%	$0.0106	5,419,967	$ 57,452	$0.7268	$0.7162	$ 827.14	$ 812 38	$ 14.76	1 82%						
20	Nov 17 - Apr 18	10.6%	$0.0200	5,298,900	$ 105,978	$0.6645	$0.6445	$ 878.70	$ 865 94	$ 12.76	1.47%						
21	Nov 18 - Apr 19					$0.7611	$0.7411	$ 984.83	$ 972.12	$ 12.71	1 31%						
22	Total									$ 734.45						$ 274.09	

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

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

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

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

Company Allowance Calculation

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

Lost and Unaccounted For Gas ("LAUF") Calculation

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

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

Fuel Inventory Revenue Requirement

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

REDACTED

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 19-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Winter 2019/2020 Cost of Gas Filing
Summer 2020 Cost of Gas Filing

DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

September 3, 2019

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I. INTRODUCTION

Q. Please state your full name and business address.

A. (DS) My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

(CM) My name is Catherine A. McNamara. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("Liberty"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

Q. Please describe your educational background and your business and professional experience.

A. (DS) I graduated from Ferris State University in 1993 with a Bachelor of Science in Finance. I received a Master's of Science in Finance from Walsh College in 2000. I also received a Master's of Business Administration from Walsh College in 2001. In 2006, I earned a Graduate Certificate in Power Systems Management from Worcester Polytechnic Institute. In August 2013, I joined Liberty as a Utility Analyst and I was promoted to Manager, Rates and Regulatory Affairs in August 2017. Prior to my employment at Liberty, I was employed by NSTAR Electric & Gas ("NSTAR") as a Senior Analyst in Energy Supply from 2008 to 2012. Prior to my position in Energy

Supply at NSTAR, I was a Senior Financial Analyst within the NSTAR Investment Planning group from 2004 to 2008.

(CM) I graduated from the University of Massachusetts, Boston, in 1993 with a Bachelor of Science in Management with a concentration in Accounting. In November 2017, I joined Liberty as an Analyst in Rates and Regulatory Affairs. Prior to my employment at Liberty, I was employed by Eversource as a Senior Analyst in the Investment Planning group from 2015 to 2017. From 2008 to 2015, I was a Supervisor in the Plant Accounting department. Prior to my position in Plant Accounting, I was a Financial Analyst/General Ledger System Administrator within the Accounting group from 2000 to 2008.

Q. Have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. (DS) Yes. I have testified on numerous occasions before the Commission.

(CM) Yes. I have testified on multiple occasions before the Commission.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's proposed firm sales cost of gas rates for the 2019/2020 Winter (Peak) Period and the Company's proposed 2019/2020 Local Delivery Adjustment Clause, both effective November 1, 2019. Our testimony also explains the Company's proposed firm sales cost of gas rates for the 2020 Summer (Off-Peak) Period.

II. WINTER 2019/2020 COST OF GAS FACTOR

Q. What are the proposed firm Winter sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.6203 per therm for residential customers, $0.6190 per therm for commercial/industrial high winter use customers, and $0.6258 per therm for commercial/industrial low winter use customers as shown on Proposed Sixth Revised Page 92 (Bates 049). The Company proposes a firm transportation cost of gas rate of $0.0009 per therm as shown on Proposed Third Revised Page 94 (Bates 051).

Q. Please explain tariff page and Proposed Sixth Revised Page 92 (Bates 049).

A. Proposed Sixth Revised Page 92 contains the calculation of the 2019/2020 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 92, the proposed 2019/2020 Average Cost of Gas of $0.6203 per therm is derived by adding the Direct Cost of Gas Rate of $0.5947 per therm to the Indirect Cost of Gas Rate of $0.0256 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Page 92, is $52,211,274. The estimated Indirect Cost of Gas, also derived on Page 92, is $2,251,330. The Direct Cost of Gas Rate of $0.5947 and the Indirect Cost of Gas Rate of $0.0256 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 87,788,508 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 92.1 (Bates 050), total $275,601. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $51,935,672 to determine the Total Anticipated Direct Cost of Gas of $52,211,274.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Original Page 92.1 consists of the following components:

1.	Purchased Gas Demand Costs	$10,157,458
2.	Purchased Gas Commodity Costs	34,260,417
3.	Storage Demand and Capacity Costs	902,742
4.	Storage Commodity Costs	4,281,375
5.	Produced Gas Cost	2,333,680
	Total	$51,935,672

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Original Page 92.1, are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$1,912,210
2.	Interest	(81,952)
3.	Fuel Inventory Revenue Requirement	351,641
4.	Broker Revenues	(30,924)
5.	Transportation COG Revenue	(44,891)
6.	Capacity Release Margin	(1,875,483)
7.	Fixed Price Administrative Cost	45,000
	Total Adjustments	$275,601

These allowable adjustments are standard adjustments made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. We discuss the factors contributing to the prior period under collection later in this testimony.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in Docket No. DG 18-137 for the 2018/2019 Winter Period?

A. The average cost of gas rate proposed in this filing of $0.6203 per therm is $0.1208 per therm less than the initial rate of $0.7411 per therm approved by the Commission in Order No. 26,188 (November 1, 2018) in Docket No. DG 18-137. The $0.1208 per therm decrease in the rate reflects an $8,411,494 decrease in the Total Unadjusted Direct Cost of Gas Cost of Gas.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2018/2019 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0009 per therm (Bates 051). The rate approved in Docket No. DG 18-137 was $0.0005 per therm. The increase in the rate relates primarily to an estimated $30,335 increase in costs due to the difference between the winter season 2018/2019 beginning balance of $59,496 (an over-collection) and the winter season 2019/2020 beginning balance of $29,161 (an over-collection).

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. No. The Company used, for pressure support purposes, a rate of 8.7% based on the marginal cost study used for the rate design approved in Docket No. DG 17-048.

Q. Did the Company include a fuel inventory revenue requirement calculation in this filing?

A. Yes (Bates 199). The Company is proposing to collect $351,641 in fuel inventory revenue requirement consistent with Order No. 26,156 (July 10, 2018) in Docket No. DG 17-048. The impact of this amount to the overall Cost of Gas rate is $0.0040 per therm which is determined by dividing the $351,641 by the estimated November 2019 through October 2020 COG sales volumes of 87,788,508 therms.

Q. How was the statutory tax rate of 27.08% calculated (Bates 199)?

A. The statutory rate of 27.08% was calculated by using a 21% federal tax rate and a 7.7% tax rate for the State of New Hampshire (0.21 + 0.077 – (0.21 x 0.077) = 0.27083).

Q. How was the common equity pre-tax rate of 6.280% calculated (Bates 199)?

A. The common equity pre-tax rate of 6.280% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 17-048, by 0.72917 (1 – 0.27083) [statutory tax rate – see previous question]) and multiplied by 49.20% (equity component of the capital structure approved in DG 17-048) [0.093 / 0.72917 x 0.4920 = 0.0628].

Q. Has the bad debt percentage in this filing of 1.11% changed from the bad debt percentage calculated in the Winter 2018/2019 Cost of Gas Reconciliation?

A. Yes, the bad debt percentage of 1.11% used in this filing is the calculated rate for the period of May 2018–April 2019. This is a $0.59 decrease from the calculated rate filed in the Winter 2018/2019 COG filing of 1.70%.

Q. What was the actual weighted average firm sales cost of gas rate for the 2018/2019 winter period?

A. The weighted average cost of gas rate was $0.6633 per therm (Bates 092 Line 54). This was calculated by applying the actual monthly cost of gas rates for November 2018 through April 2019 to the monthly therm usage of an average residential heating customer using 809 therms per year, or 666 therms for the six winter period months.

III. PRIOR WINTER PERIOD UNDER-COLLECTION

Q. Please explain the prior period under collection of $1,912,210.

A. The prior period under-collection is detailed in the 2018/2019 Winter Period Reconciliation that was filed with the Commission on August 22, 2019. The $1,912,210 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2019. The under-collection was driven mainly by the lag in the timing of monthly cost of gas rate adjustments as compared to changes in the underlying costs.

IV. FIXED PRICE OPTION

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?

A. Yes. Pursuant to Order No. 24,515 in Docket No. DG 05-127, the Fixed Price Option Program ("FPO") rates are set at $0.0200 per therm higher than the initial proposed COG rate. Proposed Second Revised Page 91 (Bates 048) contains the FPO rate for the 2019/2020 Winter period, which is $0.6403 per therm for residential customers. This compares to the FPO rate approved for the 2018/2019 winter period of $0.7611 per therm for residential customers. This represents a $0.1208 per therm, or 15.8% decrease in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 666 therms is a decrease of approximately $82.11 or 16.2% compared to last winter. The total bill impact reflects the overall rates in effect following implementation of the increases approved in Docket No. DG 19-054, effective July 1, 2019, relating to the cast iron/bare steel main replacement program. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $13.32 (or 1.45%) higher than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 (Bates 196) contains the historical results of the FPO program.

V. <u>LOCAL DELIVERY ADJUSTMENT CLAUSE (“LDAC”)</u>

Q. What are the surcharges that will be billed under the LDAC?

A. As shown on Proposed Second Revised Page 97 (Bates 054), the Company is submitting for approval an LDAC of $0.0635 per therm for the residential non-heating class and residential heating class, and $0.0494 per therm for the commercial/industrial bundled sales classes, effective November 1, 2019. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Factor, the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism, the Environmental Surcharge for Manufactured Gas Plant (“MGP”) remediation, the Residential Low Income Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 17-048.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2019, through October 31, 2020, forecasted Keene therm sales of 1,542,677 are added to the EnergyNorth therm sales forecast of 185,636,009 for a total therm sales forecast of 187,178,686 (slightly off due to rounding).

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2019 that will be filed with the Commission in the near future. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period under-recovery of the Company's residential and commercial energy efficiency programs as of October 2019. As shown on Schedule 19 Energy Efficiency (Bates 132-134), the proposed Energy Efficiency charge is $0.0640 per therm for Residential customers and $0.0426 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Factor ("RDAF").

A. This is the initial calculation of the RDAF since the implementation of decoupling on November 1, 2019. The purpose of the RDAF is to recover or refund, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. While in the process of preparing the necessary calculations, it was discovered that with respect to low-income customers the formulas approved in the

Company's tariff to calculate the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer do not use the same basis between the two formulas to calculate the revenue per customer. The approved Benchmark Base Revenue per Customer calculation uses low income residential heating revenue (rate R-4) in the calculation while the Actual Base Revenue per Customer calculation uses the residential heating rate (rate R-3) to calculate the rate R-4 revenue. In other words, the formulas in the tariff use the R-4 rate to calculate the benchmark R-4 revenue per customer and use the R-3 rate to calculate the actual R-4 revenue per customer. Schedule 19 RDAF (Bates 118-123) shows the proposed Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation of a total over-collection of $4,691,932 effective November 1, 2019, through October 31, 2020. In that calculation, the Company has aligned the Base Revenue per Customer and Benchmark Revenue per Customer calculations related to low income customers. Schedule 19 RDAF (Bates 124–129) shows the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation reflecting the current language in the tariff, which results in a total over-collection of $6,642,895 effective November 1, 2019, through October 31, 2020, based on the formulas in the Company's tariff.

Q. What would be the effect of using the calculation based on the current tariff language?

A. The net effect would be that the dollars collected to recover the costs of the low-income program would effectively be returned to customers through the RDAF mechanism.

Q. Please explain the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism ("LRAM").

A. As shown on Schedule 19 LRAM (Bates 116–117), the proposed LRAM charge is $0.0001 per therm for residential customers and $0.0001 per therm for commercial and industrial customers. It is designed to recover lost revenues associated with energy efficiency measures installed under the EERS programs. Since the Company implemented decoupling effective November 1, 2019, the Company will continue to implement its Lost Revenue Adjustment only as a prior period true-up mechanism effective November 1, 2019, and ending October 31, 2020.

Q. What is the proposed Residential Low Income Assistance Program ("RLIAP") charge?

A. As shown on Schedule 19 RLIAP (Bates 130–131), the proposed RLIAP charge is $0.0123 per therm. It is designed to recover administrative costs, revenue shortfall, and the prior period reconciliation adjustment relating to this program. For the 2019/2020 Winter Period, the Company is providing a 60% base rate discount, consistent with the settlement agreement approved by the Commission in Order No. 24,669 (Sept. 22, 2006) in Docket No. DG 06-120. The proposed RLIAP charge is designed to recover $2,307,356, of which $1,861,760 is for the revenue shortfall resulting from 5,932 customers receiving a 60% discount off their base rates, and $445,596 for the prior year reconciling adjustment.

Q. In Order No. 24,824 (Feb. 29, 2008) in Docket No. DG 06-122 relating to short-term debt issues, the Company agreed to adjust its short-term debt limits each year as part of the Company's Winter Period Cost of Gas filing. Did the Company calculate the short-term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Schedule 24 (Bates 197) the short-term debt limit for fuel and non-fuel purposes for the 2019/20 period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2019, through October 31, 2020, is calculated to be $16,338,781 and the limit for non-fuel purposes is calculated to be $99,644,640.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 95)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism, as well as the third party recoveries, are included in the Environmental Cost Summary in Schedule 20 (Bates 135) of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Casey in her pre-filed direct testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Schedule 20. The Summary included in Schedule 20 shows the remediation cost pools for the Concord Pond, Concord MGP, Manchester, Nashua, and Laconia sites, and a General Pool for costs that cannot be directly assigned to a specific site.

A summary sheet and detailed backup spreadsheets that support the 2018/2019 costs are provided in Schedule 20 of this filing. Ms. Casey's testimony describes the Company's activities with regard to all five sites.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2019, and ending October 31, 2020, is $0.0153 per therm. Consistent with filings made over the past few years, this surcharge will recover a total of $2,860,522 in amortized remediation costs. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing. This surcharge has not included recovery of any beginning balance transferred over from National Grid when the Company was acquired by Liberty Energy Utilities Corp. in Docket No. DG 11-040 nor has the surcharge included any actual to forecast true-up refund or recovery since the acquisition as provided for in the Company's tariff. The Company is planning to submit an environmental reconciliation to PUC audit staff for review and opinion by January 15, 2020. Audit Staff findings will be addressed in the Winter 2020/2021 COG filing.

Q. Did the Company include a Rate Case Expense (RCE) surcharge in this filing?

A. Yes. As shown on Schedule 19 RCE (Bates 114–115), the Company is proposing to collect $309,225 in uncollected rate case and recoupment expense consistent with Order No. 26,122 (April 27, 2018) in Docket No. DG 17-048. The RCE rate of $0.0017 per therm is determined by dividing the $309,225 by the estimated November 2019 through October 2020 sales volumes of 187,178,686 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2019 through October 2020 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 198) the Company has recalculated its Company Allowance for the period November 2019 through October 2020. The Company calculated the Company Allowance of 1.92% based on sendout and throughput data for the twelve-month period ending June 2019. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2019.

VI. CUSTOMER BILL IMPACTS

Q. What are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's winter bill as compared to the winter rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 (Bates 092) of this filing. These bill impacts reflect the implementation of the increases approved in Docket No. DG 19-054 effective July 1, 2019, relating to the cast iron/bare steel main replacement program. The total bill impact over the winter period for an average residential heating customer is a decrease of approximately $24.76 or 2.6%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is a decrease of approximately

$129.12, or 5.2% (Bates 093). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed Second Revised Page 147 (Bates 055) relating to Supplier Balancing and Peaking Demand Charges and Proposed Second Revised Page 148 (Bates 056) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 147.

A. In Proposed Second Revised Page 147, the Company is updating the Peaking Demand Charge from $20.41 per MMBtu of Peak MDQ to $18.12 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 187).

Q. Please describe the changes to tariff Page 148.

A. Proposed Second Revised Page 148 updates the Capacity Allocator percentages used to allocate pipeline, storage, and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 (Bates 190–195) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2020 COST OF GAS FACTOR

Q. What are the proposed 2020 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.4520 per therm for residential customers, $0.4474 per therm for commercial/industrial high winter use customers, and $0.4591 per therm for commercial/industrial low winter use customers as shown on Proposed Eighth Revised Page 89 (Bates 205).

Q. Please explain tariff pages Proposed Third Revised Page 88 and Proposed Ninth Revised Page 89.

A. Proposed Third Revised Page 88 (Bates 204) and Proposed Ninth Revised Page 89 contain the calculation of the 2020 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed Ninth Revised Page 89, the 2020 Average Cost of Gas of $0.4520 per therm is derived by adding the Direct Cost of Gas Rate of $0.4603 per therm to the Indirect Cost of Gas Rate of ($0.0083) per therm. The estimated total Anticipated Direct Cost of gas is $9,653,380 and the estimated Indirect Cost of Gas is ($174,652). The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected Summer firm sales volumes of 20,973,031 therms. Proposed Ninth Revised Page 89 further shows that the Residential Cost of Gas Rate of $0.4520 per therm is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial High Winter Use Cost of Gas Rate of $0.4474 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.4591 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed Third Revised Page 88. To derive the total Anticipated Direct Cost of Gas of $9,653,380, the Company starts with the Unadjusted Anticipated Cost of Gas of $7,685,193 and adds the Net Adjustment totaling $1,968,188.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1. Purchased Gas Demand Costs	$4,548,346
2. Purchased Gas Supply Costs	3,114,165
3. Produced Gas Costs	22,682
Total Unadjusted Anticipated Cost of Gas	$7,685,193

Q. What are the components of the adjustments to the cost of gas?

A. The adjustments to gas costs, listed on proposed Third Revised Page 88, are as follows:

1. Prior Period (Over)/Under Collection	$1,885,446
2. Interest	82,742
Total Adjustments	$1,968,188

Q. How does the proposed average Residential Summer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2020 Summer Period?

A. The cost of gas rate proposed in this filing is $0.0075 per therm higher than the initial rate approved by the Commission for the 2019 Summer Period ($0.4445 vs. $0.4520)

(Schedule 8, Bates 228). This increase is primarily due to a $1,268,403 estimated under-collection increase compared to the under-collection from the prior summer period.

Q. Does this conclude your testimony?

A. Yes, it does.

Liberty Utilities

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October 7, 2019

NHPUC 7OCT'19PM4:15

Via Hand-Delivery and Electronic Mail

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

Re: DG 19-145 Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities Winter 2019/2020 Cost of Gas and Summer 2020 Cost of Gas

Dear Ms. Howland:

On behalf of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, enclosed please find an original and six copies of revised pages to the testimony and attachments in this docket.

These revisions (1) update the LDAC to properly reflect the Revenue Decoupling Adjustment Factor ("RDAF"), (2) incorporate revised RDAF tariff language pursuant to an agreement with Staff and the OCA reached during technical sessions in this docket, and (3) correct a separate RDAF formula error.

Thank you for your assistance with this matter. Please do not hesitate to contact me should you have any questions.

Sincerely,

Michael J. Sheehan

Enclosures
cc: Service List

compares to the FPO rate approved for the 2018/2019 winter period of $0.7611 per therm for residential customers. This represents a $0.1208 per therm, or 15.8% decrease in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 666 therms is a decrease of approximately $98.27 or 9.75% compared to last winter. The total bill impact reflects the overall rates in effect following implementation of the increases approved in Docket No. DG 19-054, effective July 1, 2019, relating to the cast iron/bare steel main replacement program. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $13.32 (or 1.45%) higher than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 (Bates 196) contains the historical results of the FPO program.

V. <u>LOCAL DELIVERY ADJUSTMENT CLAUSE ("LDAC")</u>

Q. What are the surcharges that will be billed under the LDAC?

A. As shown on Proposed Second Revised Page 97 (Bates 054), the Company is submitting for approval an LDAC of $0.0310 per therm for the residential non-heating class and residential heating class, and $0.0478 per therm for the commercial/industrial bundled sales classes, effective November 1, 2019. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Factor, the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Low Income Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 17-048.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2019, through October 31, 2020, forecasted Keene therm sales of 1,542,677 are added to the EnergyNorth therm sales forecast of 185,636,009 for a total therm sales forecast of 187,178,686 (slightly off due to rounding).

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2019 that will be filed with the Commission in the near future. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period under-recovery of the Company's residential and commercial energy efficiency programs as of October 2019. As shown on Schedule 19 Energy Efficiency (Bates 132-134), the proposed Energy Efficiency charge is $0.0640 per therm for Residential customers and $0.0426 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Factor ("RDAF").

A. Schedule 19 RDAF (Bates 124-R–129-R) shows the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation which results in a total over-collection of $7,016,791 effective November 1, 2019, through October 31, 2020, based on the formulas in the Company's proposed tariff. The Actual Base Revenue per

Customer proposed tariff change includes weather-normalized actuals as discussed with Commission Staff at the technical session held on September 23, 2019.

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therm is determined by dividing the $309,225 by the estimated November 2019 through October 2020 sales volumes of 187,178,686 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2019 through October 2020 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 198) the Company has recalculated its Company Allowance for the period November 2019 through October 2020. The Company calculated the Company Allowance of 1.92% based on sendout and throughput data for the twelve-month period ending June 2019. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2019.

VI. <u>CUSTOMER BILL IMPACTS</u>

Q. What are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's winter bill as compared to the winter rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 (Bates 092-R) of this filing. These bill impacts reflect the implementation of the increases approved in Docket No. DG 19-054 effective July 1, 2019, relating to the cast iron/bare steel main replacement program. The total bill impact over the winter period for an average residential heating customer is a decrease of approximately $46.46 or 4.93%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is a decrease of approximately $132.18, or 5.35% (Bates 093-R). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed Second Revised Page 147 (Bates 055) relating to Supplier Balancing and Peaking Demand Charges and Proposed Second Revised Page 148 (Bates 056) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 147.

A. In Proposed Second Revised Page 147, the Company is updating the Peaking Demand Charge from $20.41 per MMBtu of Peak MDQ to $18.12 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 187).

Q. Please describe the changes to tariff Page 148.

A. Proposed Second Revised Page 148 updates the Capacity Allocator percentages used to allocate pipeline, storage, and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 (Bates 190–195) contains the six-page worksheet that backs up the calculations for the updated allocators.

NHPUC NO. 10 - GAS
LIBERTY UTILITIES

Revised Proposed Fourteenth Revised Page 84
Superseding Thirteenth Revised Page 84

II RATE SCHEDULES
FIRM RATE SCHEDULES

	~~Rates effective April 1, 2019 - April 30, 2020~~ Rates effective November 1, 2019 - April 30, 2020 Winter Period				~~Rates Effective September 1, 2018 - October 31, 2018~~ Rates Effective July 1, 2019 - October 31, 2019 Summer Period			
	Delivery Charge	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**
Residential Non Heating - R-1	~~$ 15.02~~			~~$ 15.02~~	~~$ 15.02~~			~~$ 15.02~~
Customer Charge per Month per Meter	$ 15.20			$ 15.20	$ 15.20			$ 15.20
All Therms	$ 0.3786	$ 0.6203	$ 0.0310	$ 1.0299	$ 0.3786	$ 0.5556	$ 0.0660	$ 1.0002
	~~$ 0.3741~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.0226~~	~~$ 0.3938~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.8799~~
Residential Heating - R-3	~~$ 15.02~~			~~$ 15.02~~	~~$ 15.02~~			~~$ 15.02~~
Customer Charge per Month per Meter	$ 15.20			$ 15.20	$ 15.20			$ 15.20
Size of the first block	all therms				all therms			
All Therms	$ 0.5569	$ 0.6203	$ 0.0310	$ 1.2082	$ 0.5569	$ 0.5556	$ 0.0660	$ 1.1785
	~~$ 0.5502~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.1987~~	~~$ 0.5631~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 1.0492~~
Residential Heating - R-4	~~$ 6.01~~			~~$ 6.01~~	~~$ 6.00~~			~~$ 6.00~~
Customer Charge per Month per Meter	$ 6.08			$ 6.08	$ 6.08			$ 6.08
Size of the first block	all therms				all therms			
All Therms	$ 0.2228	$ 0.6203	$ 0.0310	$ 0.8740	$ 0.2228	$ 0.5556	$ 0.0660	$ 0.8444
	~~$ 0.2201~~	~~$ (0.5825)~~	~~$ 0.0660~~	~~$ (0.2964)~~	~~$ 0.2252~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.7113~~
Commercial/Industrial - G-41	~~$ 55.68~~			~~$ 55.68~~	~~$ 56.58~~			~~$ 56.58~~
Customer Charge per Month per Meter	$ 56.36			$ 56.36	$ 56.36			$ 56.36
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.4621	$ 0.6190	$ 0.0478	$ 1.1290	$ 0.4621	$ 0.5521	$ 0.0757	$ 1.0899
	~~$ 0.4566~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.1140~~	~~$ 0.4639~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.9257~~
All therms over the first block per month at	$ 0.3104	$ 0.6190	$ 0.0478	$ 0.9773	$ 0.3104	$ 0.5521	$ 0.0757	$ 0.9382
	~~$ 0.3067~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9641~~	~~$ 0.3116~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.7734~~
Commercial/Industrial - G-42	~~$ 167.06~~			~~$ 167.06~~	~~$ 169.75~~			~~$ 169.75~~
Customer Charge per Month per Meter	$ 169.09			$ 169.09	$ 169.09			$ 169.09
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4202	$ 0.6190	$ 0.0478	$ 1.0871	$ 0.4202	$ 0.5521	$ 0.0757	$ 1.0480
	~~$ 0.4152~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.0726~~	~~$ 0.4219~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.8837~~
All therms over the first block per month at	$ 0.2800	$ 0.6190	$ 0.0478	$ 0.9468	$ 0.2800	$ 0.5521	$ 0.0757	$ 0.9078
	~~$ 0.2766~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9340~~	~~$ 0.2811~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.7429~~
Commercial/Industrial - G-43	~~$ 716.95~~			~~$ 716.95~~	~~$ 728.47~~			~~$ 728.47~~
Customer Charge per Month per Meter	$ 725.66			$ 725.66	$ 725.66			$ 725.66
All therms over the first block per month at	$ 0.2583	$ 0.6190	$ 0.0478	$ 0.9251	$ 0.1181	$ 0.5521	$ 0.0757	$ 0.7459
	~~$ 0.2552~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9126~~	~~$ 0.1185~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.5803~~
Commercial/Industrial - G-51	~~$ 55.68~~			~~$ 55.68~~	~~$ 56.58~~			~~$ 56.58~~
Customer Charge per Month per Meter	$ 56.36			$ 56.36	$ 56.36			$ 56.36
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.2785	$ 0.6258	$ 0.0478	$ 0.9522	$ 0.2785	$ 0.5633	$ 0.0757	$ 0.9175
	~~$ 0.2752~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.9379~~	~~$ 0.2796~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.7683~~
All therms over the first block per month at	$ 0.1811	$ 0.6258	$ 0.0478	$ 0.8547	$ 0.1811	$ 0.5633	$ 0.0757	$ 0.8201
	~~$ 0.1789~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8416~~	~~$ 0.1817~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.6704~~
Commercial/Industrial - G-52	~~$ 167.06~~			~~$ 167.06~~	~~$ 169.75~~			~~$ 169.75~~
Customer Charge per Month per Meter	$ 169.09			$ 169.09	$ 169.09			$ 169.09
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2392	$ 0.6258	$ 0.0478	$ 0.9128	$ 0.1733	$ 0.5633	$ 0.0757	$ 0.8123
	~~$ 0.2363~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8990~~	~~$ 0.1740~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.6627~~
All therms over the first block per month at	$ 0.1593	$ 0.6258	$ 0.0478	$ 0.8329	$ 0.0985	$ 0.5633	$ 0.0757	$ 0.7375
	~~$ 0.1574~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8201~~	~~$ 0.0989~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5876~~
Commercial/Industrial - G-53	~~$ 737.84~~			~~$ 737.84~~	~~$ 749.68~~			~~$ 749.68~~
Customer Charge per Month per Meter	$ 746.81			$ 746.81	$ 746.81			$ 746.81
All therms over the first block per month at	$ 0.1672	$ 0.6258	$ 0.0478	$ 0.8408	$ 0.0802	$ 0.5633	$ 0.0757	$ 0.7192
	~~$ 0.1652~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8279~~	~~$ 0.0805~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5692~~
Commercial/Industrial - G-54	~~$ 737.84~~			~~$ 737.84~~	~~$ 749.68~~			~~$ 749.68~~
Customer Charge per Month per Meter	$ 746.81			$ 746.81	$ 746.81			$ 746.81
All therms over the first block per month at	$ 0.0638	$ 0.6258	$ 0.0478	$ 0.7374	$ 0.0346	$ 0.5633	$ 0.0757	$ 0.6736
	~~$ 0.0630~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.7257~~	~~$ 0.0347~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5234~~

Issued: ~~October xx, 2018~~ October xx, 2019

Effective: ~~November 1, 2018~~ November 1, 2019

Issued by: ______________________
Susan L. Fleck
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2019 in Docket DG 19-xxx.
~~Issued in compliance with NHPUC Order No. 26,188 dated November 01, 2018 in Docket DG 18-137~~

II RATE SCHEDULES
FIRM RATE SCHEDULES

	~~Rates effective April 1, 2019 - April 30, 2020~~ Rates effective November 1, 2019 - April 30, 2020 Winter Period				~~Rates Effective Sptember 1, 2018 - October 31, 2018~~ Rates Effective July 1, 2019 - October 31, 2019 Summer Period			
	Delivery Charge	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**
Residential Non Heating - R-5	~~$ 19.53~~			~~$ 19.53~~	~~$ 19.52~~			~~$ 19.52~~
Customer Charge per Month per Meter	$ 19.76			$ 19.76	$ 19.76			$ 19.76
All Therms	$ 0.4922	$ 0.6203	$ 0.0310	$ 1.1435	$ 0.4922	$ 0.5556	$ 0.0660	$ 1.1138
	~~$ 0.4863~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.1348~~	~~$ 0.5119~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.9980~~
Residential Heating - R-6	~~$ 19.53~~			~~$ 19.53~~	~~$ 19.52~~			~~$ 19.52~~
Customer Charge per Month per Meter	$ 19.76			$ 19.76	$ 19.76			$ 19.76
Size of the first block	100 therms							
Therms in the first block per month at	$ 0.7240	$ 0.6203	$ 0.0310	$ 1.3752	$ 0.7240	$ 0.5556	$ 0.0660	$ 1.3456
	~~$ 0.7153~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.3638~~	~~$ 0.7320~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 1.2181~~
Residential Heating - R-7	~~$ 7.81~~			~~$ 7.81~~	~~$ 7.81~~			~~$ 7.81~~
Customer Charge per Month per Meter	$ 7.90			$ 7.90	$ 7.90			$ 7.90
Size of the first block	100 therms							
Therms in the first block per month at	$ 0.2896	$ 0.6203	$ 0.0310	$ 0.9409	$ 0.2896	$ 0.5556	$ 0.0660	$ 0.9112
	~~$ 0.2861~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 0.9346~~	~~$ 0.2928~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.7789~~
Commercial/Industrial - G-44	~~$ 72.38~~			~~$ 72.38~~	~~$ 73.56~~			~~$ 73.56~~
Customer Charge per Month per Meter	$ 73.26			$ 73.26	$ 73.26			$ 73.26
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.6008	$ 0.6190	$ 0.0478	$ 1.2676	$ 0.6008	$ 0.5521	$ 0.0757	$ 1.2286
	~~$ 0.5936~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.2510~~	~~$ 0.6031~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 1.0649~~
All therms over the first block per month at	$ 0.4036	$ 0.6190	$ 0.0478	$ 1.0704	$ 0.4035	$ 0.5521	$ 0.0757	$ 1.0313
	~~$ 0.3987~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.0561~~	~~$ 0.4051~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.8669~~
Commercial/Industrial - G-45	$ 217.18			~~$ 217.18~~	~~$ 220.68~~			~~$ 220.68~~
Customer Charge per Month per Meter	$ 219.82			$ 219.82	$ 219.82			$ 219.82
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.5463	$ 0.6190	$ 0.0478	$ 1.2131	$ 0.5463	$ 0.5521	$ 0.0757	$ 1.1741
	~~$ 0.5398~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.1972~~	~~$ 0.5485~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 1.0103~~
All therms over the first block per month at	$ 0.3639	$ 0.6190	$ 0.0478	$ 1.0308	$ 0.3639	$ 0.5521	$ 0.0757	$ 0.9917
	~~$ 0.3596~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.0170~~	~~$ 0.3654~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.8272~~
Commercial/Industrial - G-46	~~$ 932.04~~			~~$ 932.04~~	~~$ 947.01~~			~~$ 947.01~~
Customer Charge per Month per Meter	$ 943.36			$ 943.36	$ 943.36			$ 943.36
All therms over the first block per month at	$ 0.3358	$ 0.6190	$ 0.0478	$ 1.0026	$ 0.1535	$ 0.5521	$ 0.0757	$ 0.7813
	~~$ 0.3318~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9892~~	~~$ 0.1540~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.6158~~
Commercial/Industrial - G-55	~~$ 72.3800~~			~~$ 72.38~~	~~$ 73.5600~~			~~$ 73.56~~
Customer Charge per Month per Meter	$ 73.26			$ 73.26	$ 73.26			$ 73.26
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.3621	$ 0.6258	$ 0.0478	$ 1.0357	$ 0.3621	$ 0.5633	$ 0.0757	$ 1.0011
	~~$ 0.3578~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 1.0205~~	~~$ 0.3635~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.8522~~
All therms over the first block per month at	$ 0.2354	$ 0.6258	$ 0.0478	$ 0.9090	$ 0.2354	$ 0.5633	$ 0.0757	$ 0.8744
	~~$ 0.2326~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8953~~	~~$ 0.2363~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.7250~~
Commercial/Industrial - G-56	~~$ 217.1800~~			~~$ 217.18~~	~~$ 220.6800~~			~~$ 220.68~~
Customer Charge per Month per Meter	$ 219.82			$ 219.82	$ 219.82			$ 219.82
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.3109	$ 0.6258	$ 0.0478	$ 0.9846	$ 0.2253	$ 0.5633	$ 0.0757	$ 0.8643
	~~$ 0.3072~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.9699~~	~~$ 0.2262~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.7149~~
All therms over the first block per month at	$ 0.2071	$ 0.6258	$ 0.0478	$ 0.8807	$ 0.1280	$ 0.5633	$ 0.0757	$ 0.7670
	~~$ 0.2046~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8673~~	~~$ 0.1286~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.6173~~
Commercial/Industrial - G-57	~~$ 959.1900~~			~~$ 959.19~~	~~$ 974.5900~~			~~$ 974.59~~
Customer Charge per Month per Meter	$ 970.84			$ 970.84	$ 970.84			$ 970.84
All therms over the first block per month at	$ 0.2174	$ 0.6258	$ 0.0478	$ 0.8910	$ 0.1043	$ 0.5633	$ 0.0757	$ 0.7433
	~~$ 0.2148~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8775~~	~~$ 0.1047~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5934~~
Commercial/Industrial - G-58	~~$ 959.1900~~			~~$ 959.19~~	~~$ 974.5900~~			~~$ 974.59~~
Customer Charge per Month per Meter	$ 970.85			$ 970.85	$ 970.84			$ 970.84
All therms over the first block per month at	$ 0.0829	$ 0.6258	$ 0.0478	$ 0.7565	$ 0.0450	$ 0.5633	$ 0.0757	$ 0.6840
	~~$ 0.0819~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.7446~~	~~$ 0.0448~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5335~~

Issued: ~~October xx, 2018~~ October xx, 2019

Effective: ~~November 1, 2018~~ November 1, 2019

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Susan L. Fleck

Title: President

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NHPUC NO. 10 - GAS | **Revised Proposed Second Revised Page 97**
LIBERTY UTILITIES | **Superseding First Revised Page 97**

Local Delivery Adjustment Clause Calculation

				Sales Customers		Transportation Customers	
Residential Non Heating Rates - R-1							
Energy Efficiency Charge	~~$ 0.0450~~		$ 0.0640				
Demand Side Management Charge	~~0.0000~~		0.0000				
Conservation Charge (CCx)		~~$ 0.0450~~		$ 0.0640			
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000				
Manufactured Gas Plants	~~0.0161~~		0.0153				
Environmental Surcharge (ES)		~~$ 0.0161~~		$ 0.0153			
Revenue Decoupling Adjustment Factor (RDAF)		~~0.0000~~		(0.0623)			
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~0.0003~~		0.0001			
Rate Case Expense Factor (RCEF)		~~0.0092~~		0.0017			
Residential Low Income Assistance Program (RLIAP)		~~0.0130~~		0.0123			
LDAC		~~**$ 0.0836**~~		**$ 0.0310**			**per therm**
Residential Heating Rates - R-3, R-4, R-6, R-7							
Energy Efficiency Charge	~~$ 0.0450~~		$ 0.0640				
Demand Side Management Charge	~~0.0000~~		0.0000				
Conservation Charge (CCx)		$ 0.0450		$ 0.0640			
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000				
Manufactured Gas Plants	~~0.0161~~		0.0153				
Environmental Surcharge (ES)		~~0.0161~~		0.0153			
Revenue Decoupling Adjustment Factor (RDAF)		~~0.0000~~		(0.0623)			
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~0.0003~~		0.0001			
Rate Case Expense Factor (RCEF)		~~0.0092~~		0.0017			
Residential Low Income Assistance Program (RLIAP)		~~0.0130~~		0.0123			
LDAC		~~**$ 0.0836**~~		**$ 0.0310**			**per therm**
Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55							
Energy Efficiency Charge	~~$ 0.0387~~		$ 0.0426				
Demand Side Management Charge	~~-~~		-				
Conservation Charge (CCx)		$ 0.0387		$ 0.0426	~~$ 0.0387~~	$ 0.0426	
Relief Holder and pond at Gas Street, Concord, NH	~~-~~		-				
Manufactured Gas Plants	~~0.0161~~		0.0153				
Environmental Surcharge (ES)		$ 0.0161		$ 0.0153	~~$ 0.0161~~	$ 0.0153	
Revenue Decoupling Adjustment Factor (RDAF)		~~0.0000~~		(0.0241)	~~0.0000~~	(0.0241)	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~0.0001~~		0.0001	~~0.0001~~	0.0001	
Rate Case Expense Factor (RCEF)		~~0.0092~~		0.0017	~~0.0092~~	0.0017	
Residential Low Income Assistance Program (RLIAP)		~~0.0130~~		0.0123	~~0.0130~~	0.0123	
LDAC		~~**$0.0772**~~		**$0.0478**	~~**$0.0772**~~	**$0.0478**	**per therm**
Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56							
Energy Efficiency Charge	~~$ 0.0387~~		$ 0.0426				
Demand Side Management Charge	~~-~~		-				
Conservation Charge (CCx)		$ 0.0387		$ 0.0426	~~$ 0.0387~~	$ 0.0426	
Relief Holder and pond at Gas Street, Concord, NH	~~-~~		-				
Manufactured Gas Plants	~~0.0161~~		0.0153				
Environmental Surcharge (ES)		$ 0.0161		$ 0.0153	~~$ 0.0161~~	$ 0.0153	
Revenue Decoupling Adjustment Factor (RDAF)		~~0.0000~~		(0.0241)	~~0.0000~~	(0.0241)	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~0.0001~~		0.0001	~~0.0001~~	0.0001	
Rate Case Expense Factor (RCEF)		~~0.0092~~		0.0017	~~0.0092~~	0.0017	
Residential Low Income Assistance Program (RLIAP)		~~0.0130~~		0.0123	~~0.0130~~	0.0123	
LDAC		~~**$ 0.0772**~~		**$ 0.0478**	**$ 0.0772**	**$ 0.0478**	**per therm**
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57, G-58							
Energy Efficiency Charge	~~$ 0.0387~~		$ 0.0426				
Demand Side Management Charge	~~-~~		-				
Conservation Charge (CCx)		$ 0.0387		$ 0.0426	~~$ 0.0387~~	$ 0.0426	
Relief Holder and pond at Gas Street, Concord, NH	~~-~~		-				
Manufactured Gas Plants	~~0.0161~~		0.0153				
Environmental Surcharge (ES)		$0.0161		0.0153	~~0.0161~~	0.0153	
Revenue Decoupling Adjustment Factor (RDAF)		~~0.0000~~		(0.0241)	~~0.0000~~	(0.0241)	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~0.0001~~		0.0001	~~0.0001~~	0.0001	
Rate Case Expense Factor (RCEF)		~~0.0092~~		0.0017	~~0.0092~~	0.0017	
Residential Low Income Assistance Program (RLIAP)		~~0.0130~~		0.0123	~~0.0130~~	0.0123	
LDAC		**$0.0772**		**$0.0478**	**$0.0772**	**$0.0478**	**per therm**

Issued: ~~October xx, 2018~~ October xx, 2019 | Issued by: ____________________
Susan L. Fleck

Effective: ~~November 1, 2018~~ November 1, 2019 | Title: President

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III DELIVERY TERMS AND CONDITIONS

ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	~~$ 0.19~~	0.21	
II.	Capacity Mitigation Fee	~~15%~~	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
III.	Peaking Demand Charge	~~$ 20.41~~	$ 18.12	
IV.	Company Allowance Calculation (per Schedule 25)			
		~~173,718,990~~	181,100,282	Total Sendout - Therms Jul-2018 - Jun-2019 ~~Total Sendout - Therms Jul-2017 - Jun-2018~~
		~~170,585,367~~	177,619,709	Total Throughput - Therms Jul-2018 - Jun-2019 ~~Total Throughput - Therms Jul-2017 - Jun-2018~~
		~~3,133,623~~	3,480,573	Variance (Sendout - Throughput)
Company Allowance Percentage	2019-20 ~~2018-19~~	~~1.8%~~	1.9%	Variance / Total Sendout

Issued: ~~October xx, 2018~~ October xx, 2019 | Issued by: ______________________
Susan L. Fleck
Effective: ############## November 1, 2019 | Title: President

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2019 - 2020 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 18 - Apr 19 vs Nov 19 - Apr 20 - Residential Heating Rate R-3

November 1, 2019 - April 30, 2020
Residential Heating (R3)

PROPOSED			**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**Winter Nov-Apr**
average Usage (Therms)			62	110	123	148	132	92	666
	5/1/2019	11/1/2019							
Winter:									
Cust. Chg	$ 15.02	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 91.20
Headblock	$ 0.5502	$ 0.5569	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.5502	$ 0.5569	$ 34.35	$ 61.12	$ 68.38	$ 82.21	$ 73.78	$ 51.15	$ 370.99
HB Threshold	-	-							
Summer:									
Cust. Chg	$ 15.02	$ 15.20							
Headblock	$ 0.5502	$ 0.5569							
Tailblock	$ 0.5502	$ 0.5569							
HB Threshold	-	-							
Total Base Rate Amount			$ 49.55	$ 76.32	$ 83.58	$ 97.41	$ 88.98	$ 66.35	$ 462.19
COG Rate - (Seasonal)			$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203
COG amount			$ 38.26	$ 68.07	$ 76.17	$ 91.57	$ 82.17	$ 56.98	$ 413.23
LDAC			$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310
LDAC amount			$ 1.91	$ 3.40	$ 3.80	$ 4.57	$ 4.10	$ 2.84	$ 20.63
Total Bill			**$ 89.73**	**$ 147.79**	**$ 163.55**	**$ 193.55**	**$ 175.25**	**$ 126.18**	**$ 896.05**

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

CURRENT			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**
average Usage (Therms)			62	110	123	148	132	92	666
Winter:	5/1/2018	11/1/2018							
Cust. Chg	$ 24.43	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 90.12
Headblock	$ 0.3863	$ 0.5502	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.3197	$ 0.5502	$ 33.94	$ 60.38	$ 67.56	$ 81.22	$ 72.89	$ 50.54	$ 366.53
HB Threshold	100	-							
Summer:									
Cust. Chg	$ 14.88	$ 15.02							
Headblock	$ 0.5580	$ 0.5631							
Tailblock	$ 0.5580	$ 0.5631							
HB Threshold	-	-							
Total Base Rate Amount			$ 48.96	$ 75.40	$ 82.58	$ 96.24	$ 87.91	$ 65.56	$ 456.65
COG Rate - (Seasonal)			$ 0.7411	$ 0.7504	$ 0.7504	$ 0.6715	$ 0.5212	$ 0.5825	$ 0.6633
COG amount			$ 45.72	$ 82.35	$ 92.14	$ 99.13	$ 69.05	$ 53.51	$ 441.89
LDAC			$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660
LDAC amount			$ 4.07	$ 7.24	$ 8.10	$ 9.74	$ 8.74	$ 6.06	$ 43.97
Total Bill			**$ 98.75**	**$ 165.00**	**$ 182.82**	**$ 205.11**	**$ 165.70**	**$ 125.13**	**$ 942.50**

DIFFERENCE:

Total Bill	**($9.02)**	**($17.21)**	**($19.27)**	**($11.56)**	**$9.56**	**$1.05**	**($46.46)**
% Change	**-9.13%**	**-10.43%**	**-10.54%**	**-5.64%**	**5.77%**	**0.84%**	**-4.93%**
Base Rate	$ 0.59	$ 0.92	$ 1.00	$ 1.17	$ 1.07	$ 0.80	$ 5.54
% Change	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%
COG & LDAC	$ (9.61)	$ (18.12)	$ (20.28)	$ (12.73)	$ 8.49	$ 0.25	$ (52.00)
% Change	-21.03%	-22.01%	-22.01%	-12.84%	12.29%	0.48%	-11.77%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2019 - 2020 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 18 - Apr 19 vs Nov 19 - Apr 20 - Commercial Rate G-41

November 1, 2019 - April 30, 2020
Commercial Rate (G-41)

PROPOSED			**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**Winter Nov-Apr**
average Usage (Therms)			89	277	504	457	331	297	1,954
Winter:	7/1/2019	5/1/2019							
Cust. Chg	$ 56.36	$ 55.68	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 338.16
Headblock	$ 0.4621	$ 0.4566	$ 40.99	$ 46.21	$ 46.21	$ 46.21	$ 46.21	$ 46.21	$ 272.04
Tailblock	$ 0.3104	$ 0.3067	$ -	$ 54.98	$ 125.36	$ 110.70	$ 71.65	$ 61.09	$ 423.78
HB Threshold	100	100							
Summer:									
Cust. Chg	$ 56.36	$ 55.68							
Headblock	$ 0.4621	$ 0.4566							
Tailblock	$ 0.3104	$ 0.3067							
HB Threshold	20	20							
Total Base Rate Amount			$ 97.35	$ 157.55	$ 227.93	$ 213.27	$ 174.22	$ 163.66	$ 1,033.97
COG Rate - (Seasonal)			$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190
COG amount			$ 54.91	$ 171.54	$ 311.89	$ 282.65	$ 204.78	$ 183.73	$ 1,209.50
LDAC			$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
LDAC amount			$ 4.24	$ 13.26	$ 24.10	$ 21.84	$ 15.82	$ 14.20	$ 93.46
Total Bill			**$156.50**	**$342.35**	**$563.91**	**$517.75**	**$394.83**	**$361.59**	**$2,336.93**

November 1, 2018 - April 30, 2019
Commercial Rate (G-41)

CURRENT			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**
average Usage (Therms)			89	277	504	457	331	297	1,954
Winter:	7/1/2018	11/1/2018							
Cust. Chg	$ 53.45	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 334.08
Headblock	$ 0.4383	$ 0.4566	$ 40.50	$ 45.66	$ 45.66	$ 45.66	$ 45.66	$ 45.66	$ 268.80
Tailblock	$ 0.2944	$ 0.3067	$ -	$ 54.33	$ 123.86	$ 109.38	$ 70.80	$ 60.37	$ 418.72
HB Threshold	100	100							
Summer:									
Cust. Chg	$ 56.58	$ 56.07							
Headblock	$ 0.4639	$ 0.4597							
Tailblock	$ 0.3116	$ 0.3088							
HB Threshold	20	20							
Total Base Rate Amount			$ 96.18	$ 155.67	$ 225.20	$ 210.72	$ 172.14	$ 161.71	$ 1,021.60
COG Rate - (Seasonal)			$ 0.7403	$ 0.7403	$ 0.7496	$ 0.6707	$ 0.5204	$ 0.5817	$ 0.6651
COG amount			$ 65.67	$ 205.16	$ 377.69	$ 306.26	$ 172.16	$ 172.66	$ 1,299.59
LDAC			$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
LDAC amount			$ 6.71	$ 20.98	$ 38.14	$ 34.57	$ 25.04	$ 22.47	$ 147.91
Total Bill			**$168.56**	**$381.80**	**$641.04**	**$551.54**	**$369.34**	**$356.84**	**$2,469.11**

DIFFERENCE:

Total Bill	**$ (12.06)**	**$ (39.45)**	**$ (77.12)**	**$ (33.78)**	**$ 25.48**	**$ 4.76**	**$ (132.18)**
% Change	**-7.16%**	**-10.33%**	**-12.03%**	**-6.13%**	**6.90%**	**1.33%**	**-5.35%**
Base Rate	$ 1.17	$ 1.89	$ 2.72	$ 2.55	$ 2.08	$ 1.96	$ 12.37
% Change	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%
COG & LDAC	$ (13.23)	$ (41.34)	$ (79.85)	$ (36.33)	$ 23.40	$ 2.80	$ (144.55)
% Change	-20.15%	-20.15%	-21.14%	-11.86%	13.59%	1.62%	-11.12%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty Utilities**
2 **Peak 2019 - 2020 Winter Cost of Gas Filing**
71 **Annual Bill Comparisons, Nov 18 - Apr 19 vs Nov 19 - Apr 20 - Commercial Rate G-42** Revised Schedule 8
72 Page 3 of 5
73
74 **November 1, 2019 - April 30, 2020**
75 **C&I High Winter Use Medium G-42**

Row				Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Winter Nov-Apr
76	**PROPOSED**									
77										
78	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,130
79		7/1/2019	5/1/2019							
80	**Winter:**									
81	Cust. Chg	$ 169.09	$ 167.06	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,014.54
82	Headblock	$ 0.4202	$ 0.4152	$ 348.79	$ 420.20	$ 420.20	$ 420.20	$ 420.20	$ 420.20	$ 2,449.79
83	Tailblock	$ 0.2800	$ 0.2766	$ -	$ 332.82	$ 758.10	$ 673.62	$ 448.79	$ 390.57	$ 2,603.90
84	HB Threshold	1,000	1,000							
85										
86	**Summer:**									
87	Cust. Chg	$169.09	$167.06							
88	Headblock	$ 0.4202	$ 0.4152							
89	Tailblock	$ 0.2800	$ 0.2766							
90	HB Threshold	400	400							
91										
92	Total Base Rate Amount			$ 517.88	$ 922.11	$ 1,347.39	$ 1,262.91	$ 1,038.08	$ 979.86	$ 6,068.23
93										
94	COG Rate - (Seasonal)			$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190
95	COG amount			$ 513.81	$ 1,354.77	$ 2,294.95	$ 2,108.18	$ 1,611.14	$ 1,482.44	$ 9,365.28
96										
97	LDAC			$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
98	LDAC amount			$ 39.70	$ 104.68	$ 177.33	$ 162.90	$ 124.49	$ 114.55	$ 723.66
99										
100	**Total Bill**			**$ 1,071.39**	**$ 2,381.56**	**$ 3,819.67**	**$ 3,533.99**	**$ 2,773.71**	**$ 2,576.85**	**$ 16,157.17**

101
102 **November 1, 2018 - April 30, 2019**
103 **C&I High Winter Use Medium G-42**

Row				Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr
104	**CURRENT**									
105										
106	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,130
107		5/1/2018	7/1/2018							
108	**Winter:**									
109	Cust. Chg	$ 160.36	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 1,002.36
110	Headblock	$ 0.3986	$ 0.4152	$ 344.64	$ 415.20	$ 415.20	$ 415.20	$ 415.20	$ 415.20	$ 2,420.64
111	Tailblock	$ 0.2655	$ 0.2766	$ -	$ 328.78	$ 748.90	$ 665.44	$ 443.34	$ 385.83	$ 2,572.28
112	HB Threshold	1,000	1,000							
113										
114	**Summer:**									
115	Cust. Chg	$ 168.21	$ 169.75							
116	Headblock	$ 0.4181	$ 0.4219							
117	Tailblock	$ 0.2785	$ 0.2811							
118	HB Threshold	400	400							
119										
120	Total Base Rate Amount			$ 511.70	$ 911.04	$ 1,331.16	$ 1,247.70	$ 1,025.60	$ 968.09	$ 5,995.28
121										
122	COG Rate - (Seasonal)			$ 0.7403	$ 0.7403	$ 0.7496	$ 0.6707	$ 0.5204	$ 0.5817	$0.6640
123	COG amount			$ 614.49	$ 1,620.25	$ 2,779.15	$ 2,284.26	$ 1,354.50	$ 1,393.11	$ 10,045.76
124										
125	LDAC			$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	0.0757
126	LDAC amount			$ 62.84	$ 165.68	$ 280.66	$ 257.82	$ 197.03	$ 181.29	$ 1,145.32
127										
128	**Total Bill**			**$ 1,189.03**	**$ 2,696.97**	**$ 4,390.97**	**$ 3,789.78**	**$ 2,577.13**	**$ 2,542.49**	**$ 17,186.36**

129
130 **DIFFERENCE:**

Row		Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
131	**Total Bill**	**$ (117.64)**	**$ (315.41)**	**$ (571.29)**	**$ (255.79)**	**$ 196.58**	**$ 34.36**	**$ (1,029.19)**
132	% Change	**-9.89%**	**-11.69%**	**-13.01%**	**-6.75%**	**7.63%**	**1.35%**	**-5.99%**
133								
134	**Base Rate**	$ 6.18	$ 11.07	$ 16.24	$ 15.21	$ 12.48	$ 11.77	$ 72.95
135	% Change	1.21%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
136								
137	**COG & LDAC**	$ (123.82)	$ (326.48)	$ (587.53)	$ (271.00)	$ 184.10	$ 22.58	$ (1,102.14)
138	% Change	-20.15%	-20.15%	-21.14%	-11.86%	13.59%	1.62%	-10.97%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2019 - 2020 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 18 - Apr 19 vs Nov 19 - Apr 20 - Commercial Rate G-52

November 1, 2019 - April 30, 2020
Commercial Rate (G-52)

PROPOSED			**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**Winter Nov-Apr**
average Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,306
Winter:	7/1/2019	5/1/2019							
Cust. Chg	$ 169.09	$ 167.06	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,014.54
Headblock	$ 0.2392	$ 0.2363	$ 239.20	$ 239.20	$ 239.20	$ 239.20	$ 239.20	$ 239.20	$ 1,435.20
Tailblock	$ 0.1593	$ 0.1574	$ 56.03	$ 137.94	$ 204.48	$ 184.73	$ 141.07	$ 121.08	$ 845.32
HB Threshold	1,000	1,000							
Summer:									
Cust. Chg	$ 169.09	$ 167.06							
Headblock	$ 0.1733	$ 0.1712							
Tailblock	$0.0985	$0.0973							
HB Threshold	1,000	1,000							
Total Base Rate Amount			$ 464.32	$ 546.23	$ 612.77	$ 593.02	$ 549.36	$ 529.37	$ 3,295.06
COG Rate - (Seasonal)			$0.6258	$0.6258	$0.6258	$0.6258	$0.6258	$0.6258	$0.6258
COG amount			$ 845.92	$ 1,167.69	$ 1,429.07	$ 1,351.49	$ 1,179.97	$ 1,101.44	$ 7,075.59
LDAC			$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	0.0478
LDAC amount			$ 64.65	$ 89.25	$ 109.22	$ 103.30	$ 90.19	$ 84.18	$ 540.79
Total Bill			**$1,374.90**	**$1,803.17**	**$2,151.06**	**$2,047.81**	**$1,819.51**	**$1,715.00**	**$10,911.44**

November 1, 2018 - April 30, 2019
Commercial Rate (G-52)

CURRENT			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**
average Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,306
Winter:	5/1/2018	7/1/2018							
Cust. Chg	$ 160.36	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 1,002.36
Headblock	$ 0.2268	$ 0.2363	$ 236.30	$ 236.30	$ 236.30	$ 236.30	$ 236.30	$ 236.30	$ 1,417.80
Tailblock	$ 0.1511	$ 0.1574	$ 55.36	$ 136.29	$ 202.04	$ 182.52	$ 139.38	$ 119.63	$ 835.24
HB Threshold	1,000	1,000							
Summer:									
Cust. Chg	$ 168.21	$ 169.75							
Headblock	$ 0.1724	$ 0.1740							
Tailblock	$ 0.0980	$ 0.0989							
HB Threshold	1,000	1,000							
Total Base Rate Amount			$ 458.72	$ 539.65	$ 605.40	$ 585.88	$ 542.74	$ 522.99	$ 3,255.40
COG Rate - (Seasonal)			$ 0.7456	$ 0.7456	$ 0.7549	$ 0.6760	$ 0.5257	$ 0.5870	$ 0.6728
COG amount			$ 1,007.86	$ 1,391.23	$ 1,723.88	$ 1,459.91	$ 991.23	$ 1,033.15	$ 7,607.26
LDAC			$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
LDAC amount			$ 102.33	$ 141.25	$ 172.87	$ 163.48	$ 142.74	$ 133.24	$ 855.90
Total Bill			**$1,568.91**	**$2,072.13**	**$2,502.15**	**$2,209.27**	**$1,676.71**	**$1,689.38**	**$11,718.56**

DIFFERENCE:

Total Bill	**$ (194.01)**	**$ (268.96)**	**$ (351.09)**	**$ (161.47)**	**$ 142.81**	**$ 25.61**	**$ (807.11)**
% Change	**-12.37%**	**-12.98%**	**-14.03%**	**-7.31%**	**8.52%**	**1.52%**	**-6.89%**
Base Rate	$ 5.60	$ 6.58	$ 7.37	$ 7.13	$ 6.61	$ 6.37	$ 39.66
% Change	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
COG & LDAC	$ (199.61)	$ (275.54)	$ (358.45)	$ (168.60)	$ 136.19	$ 19.24	$ (846.78)
% Change	-19.81%	-19.81%	-20.79%	-11.55%	13.74%	1.86%	-11.13%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty Utilities**
2 **Peak 2019 - 2020 Winter Cost of Gas Filing**

Revised Schedule 8

Row	Residential Heating	Winter 2018-19	Winter 2019-20
207	**Residential Heating**		
208		Winter 2018-19	Winter 2019-20
209	Customer Charge	$ 15.02	$ 15.20
210	First 100 Therms	$ 0.5502	$ 0.5569
211	Excess 100 Therms	$ 0.5502	$ 0.5569
212	LDAC	$ 0.0660	$ 0.0310
213	COG	$ 0.6633	$ 0.6203
214	Total Adjust	$ 0.7293	$ 0.6513
215			
216			
217			

Row		Therms	Winter 2017-18 COG @	Winter 2018-19 CO	Total $ Impact	Total % Impact	Base Rate $ Impact	Base Rate % Impact	COG $ Impact	COG % Impact	LDAC $ Impact	LDAC % Impact
220			$0.7293	$0.6513	($0.08)	-11%						
221												
222	Cooking alone	5	$21.42	$21.03	($0.39)	-2%	$0.00	0%	-$0.22	-1%	-$0.18	-1%
223												
224		10	$27.82	$27.03	($0.78)	-3%	$0.00	0%	-$0.43	-2%	-$0.35	-1%
225												
226		20	$40.61	$39.05	($1.56)	-4%	$0.00	0%	-$0.86	-2%	-$0.70	-2%
227												
228	Water Heating alone	30	$53.41	$51.06	($2.34)	-4%	$0.00	0%	-$1.29	-3%	-$1.05	-2%
229												
230		45	$72.60	$69.09	($3.51)	-5%	$0.00	0%	-$1.94	-3%	-$1.58	-2%
231												
232		50	$79.00	$75.09	($3.90)	-5%	$0.00	0%	-$2.15	-3%	-$1.75	-2%
233												
234	Heating Alone	80	$110.98	$105.13	($5.85)	-5%	$0.00	0%	-$3.23	-3%	-$2.63	-2%
235												
236		125	$185.20	$174.82	($10.38)	-6%	$0.00	0%	-$5.72	-3%	-$4.66	-3%
237												
238		150	$206.95	$195.24	($11.71)	-6%	$0.00	0%	-$6.45	-3%	-$5.25	-3%
239												
240		200	$270.93	$255.31	($15.61)	-6%	$0.00	0%	-$8.61	-3%	-$7.01	-3%
241												

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the intent of the RDAF

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the intent of the RDAF

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the intent of the RDAF

SALES AND TRANSPORT DATA

CUSTOMER COMPONENT

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the intent of the RDAF

ENERGY COMPONENT

HEADBLOCK

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the intent of the RDAF

TAILBLOCK

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the intent of the RDAF

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Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the formula in the tariff

		(1)	(2)	(3)
	Residential Revenue Decoupling Adjustment Factor			
1.	Allowed Base Revenue	$ 40,585,321		
2.	less: Actual and Estimated Base Revenue	44,670,474		
3.	Revenue Deficiency / (Excess)		$ (4,085,153)	
4.	divided by: Forecasted Residential Sales		65,525,887	
5.	Residential Revenue Decoupling Adjustment Factor			$ (0.0623)
	Commercial Revenue Decoupling Adjustment Factor			
6.	Allowed Base Revenue	$ 31,436,763		
7.	less: Actual and Estimated Base Revenue	34,368,401		
8.	Revenue Deficiency / (Excess)		$ (2,931,638)	
9.	divided by: Forecasted Commercial Sales		121,652,799	
10.	Commercial Revenue Decoupling Adjustment Factor			$ (0.0241)

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the formula in the tariff

EnergyNorth Natural Gas Inc

2018-19 Customers (Equivalent Bills)

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-18	S&T Aug-18	S&T Total
R-1	3,492	3,607	3,611	3,258	3,608	3,489	3,605	3,481	3,574	3,586	35,311
R-3	71,747	74,482	74,676	67,598	74,949	72,450	74,670	72,069	73,360	73,237	729,238
R-4	5,948	6,205	6,210	5,599	6,170	5,875	5,956	5,679	5,777	5,675	59,095
Total Resid.	**81,187**	**84,295**	**84,496**	**76,455**	**84,727**	**81,814**	**84,231**	**81,229**	**82,711**	**82,498**	**823,643**
G-41	9,279	9,683	9,716	8,804	9,751	9,385	9,526	9,043	9,125	9,104	93,416
G-42	1,388	1,439	1,441	1,303	1,442	1,386	1,427	1,375	1,452	1,415	14,067
G-43	57	60	60	54	59	56	58	56	55	56	571
G-51	1,291	1,339	1,340	1,209	1,339	1,292	1,328	1,285	1,261	1,298	12,982
G-52	378	391	390	352	392	381	396	384	396	391	3,851
G-53	37	38	37	34	35	34	36	35	38	38	363
G-54	29	30	29	27	30	28	29	28	29	29	288
Total C/I	**12,458**	**12,980**	**13,013**	**11,783**	**13,048**	**12,563**	**12,799**	**12,206**	**12,357**	**12,331**	**125,538**
Total All	**93,645**	**97,275**	**97,509**	**88,238**	**97,776**	**94,377**	**97,030**	**93,435**	**95,068**	**94,828**	**949,181**

2018-19 Benchmark Base Revenue Per Bill

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-19	S&T Aug-19
R-1	$ 23.348	$ 25.283	$ 26.012	$ 25.753	$ 24.068	$ 21.406	$ 20.682	$ 19.317	$ 18.581	$ 18.520
R-3	$ 57.780	$ 77.468	$ 88.801	$ 83.856	$ 71.842	$ 45.379	$ 33.218	$ 25.573	$ 22.855	$ 22.974
R-4	$ 22.047	$ 29.563	$ 33.409	$ 31.062	$ 28.369	$ 19.541	$ 12.971	$ 10.385	$ 9.239	$ 9.352
G-41	$ 139.367	$ 185.085	$ 211.254	$ 201.863	$ 172.188	$ 118.730	$ 88.674	$ 72.229	$ 67.581	$ 67.203
G-42	$ 821.458	$ 1,125.575	$ 1,259.787	$ 1,167.405	$ 983.555	$ 684.624	$ 472.419	$ 349.595	$ 296.514	$ 289.956
G-43	$ 6,550.598	$ 7,502.097	$ 8,664.543	$ 7,626.280	$ 6,553.396	$ 4,286.167	$ 2,095.245	$ 1,460.169	$ 1,276.137	$ 1,310.918
G-51	$ 115.703	$ 127.293	$ 130.854	$ 125.983	$ 115.870	$ 99.796	$ 94.811	$ 85.816	$ 86.305	$ 87.102
G-52	$ 627.414	$ 664.356	$ 662.625	$ 649.692	$ 593.999	$ 514.744	$ 372.278	$ 338.050	$ 345.377	$ 356.854
G-53	$ 5,223.263	$ 6,402.732	$ 5,376.660	$ 5,441.929	$ 5,316.353	$ 4,644.882	$ 2,523.664	$ 2,138.370	$ 2,145.270	$ 2,343.537
G-54	$ 4,462.745	$ 4,980.221	$ 4,323.529	$ 3,728.568	$ 2,872.867	$ 3,248.080	$ 2,004.687	$ 2,363.392	$ 2,360.857	$ 2,675.881

2018-19 Allowed Base Revenue

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-19	S&T Aug-19	S&T Total
R-1	$ 81,527	$ 91,197	$ 93,922	$ 83,891	$ 86,847	$ 74,680	$ 74,567	$ 67,246	$ 66,414	$ 66,407	$ 786,697
R-3	$ 4,145,546	$ 5,770,020	$ 6,631,299	$ 5,668,528	$ 5,384,448	$ 3,287,719	$ 2,480,407	$ 1,842,996	$ 1,676,613	$ 1,682,555	$ 38,570,131
R-4	$ 131,133	$ 183,445	$ 207,454	$ 173,927	$ 175,042	$ 114,809	$ 77,260	$ 58,978	$ 53,370	$ 53,073	$ 1,228,492
Total Resid.	**$ 4,358,207**	**$ 6,044,662**	**$ 6,932,675**	**$ 5,926,346**	**$ 5,646,337**	**$ 3,477,208**	**$ 2,632,234**	**$ 1,969,220**	**$ 1,796,397**	**$ 1,802,035**	**$ 40,585,321**
G-41	$ 1,293,228	$ 1,792,221	$ 2,052,443	$ 1,777,158	$ 1,678,971	$ 1,114,268	$ 844,671	$ 653,195	$ 616,699	$ 611,821	$ 12,434,674
G-42	$ 1,139,946	$ 1,619,826	$ 1,815,459	$ 1,521,121	$ 1,418,584	$ 948,585	$ 673,921	$ 480,758	$ 430,461	$ 410,240	$ 10,458,902
G-43	$ 370,546	$ 453,128	$ 519,296	$ 412,836	$ 387,525	$ 240,740	$ 121,245	$ 81,867	$ 70,230	$ 73,193	$ 2,730,605
G-51	$ 149,337	$ 170,455	$ 175,348	$ 152,337	$ 155,124	$ 128,940	$ 125,890	$ 110,257	$ 108,874	$ 113,043	$ 1,389,604
G-52	$ 236,995	$ 259,433	$ 258,532	$ 228,906	$ 232,868	$ 196,359	$ 147,437	$ 129,752	$ 136,923	$ 139,482	$ 1,966,686
G-53	$ 193,261	$ 240,528	$ 200,011	$ 182,849	$ 188,021	$ 160,248	$ 90,936	$ 74,629	$ 82,021	$ 89,601	$ 1,502,104
G-54	$ 129,420	$ 149,240	$ 127,207	$ 100,837	$ 86,090	$ 91,487	$ 58,002	$ 66,175	$ 68,308	$ 77,422	$ 954,188
Total C/I	**$ 3,512,731**	**$ 4,684,830**	**$ 5,148,296**	**$ 4,376,043**	**$ 4,147,181**	**$ 2,880,627**	**$ 2,062,103**	**$ 1,596,633**	**$ 1,513,516**	**$ 1,514,802**	**$ 31,436,763**
Total All	**$ 7,870,938**	**$ 10,729,492**	**$ 12,080,971**	**$ 10,302,389**	**$ 9,793,519**	**$ 6,357,835**	**$ 4,694,336**	**$ 3,565,853**	**$ 3,309,912**	**$ 3,316,837**	**$ 72,022,084**

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the formula in the tariff

SALES AND TRANSPORT DATA

CUSTOMER COMPONENT

EnergyNorth Natural Gas Inc

2018-19 Customers (Equivalent Bills)

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-18	S&T Aug-18	S&T Total
R-1	3,492	3,607	3,611	3,258	3,608	3,489	3,605	3,481	3,574	3,586	35,311
R-3	71,747	74,482	74,676	67,598	74,949	72,450	74,670	72,069	73,360	73,237	729,238
R-4	5,948	6,205	6,210	5,599	6,170	5,875	5,956	5,679	5,777	5,675	59,095
Total Resid.	**81,187**	**84,295**	**84,496**	**76,455**	**84,727**	**81,814**	**84,231**	**81,229**	**82,711**	**82,498**	**823,643**
G-41	9,279	9,683	9,716	8,804	9,751	9,385	9,526	9,043	9,125	9,104	93,416
G-42	1,388	1,439	1,441	1,303	1,442	1,386	1,427	1,375	1,452	1,415	14,067
G-43	57	60	60	54	59	56	58	56	55	56	571
G-51	1,291	1,339	1,340	1,209	1,339	1,292	1,328	1,285	1,261	1,298	12,982
G-52	378	391	390	352	392	381	396	384	396	391	3,851
G-53	37	38	37	34	35	34	36	35	38	38	363
G-54	29	30	29	27	30	28	29	28	29	29	288
Total C/I	**12,458**	**12,980**	**13,013**	**11,783**	**13,048**	**12,563**	**12,799**	**12,206**	**12,357**	**12,331**	**125,538**
Total All	**93,645**	**97,275**	**97,509**	**88,238**	**97,776**	**94,377**	**97,030**	**93,435**	**95,068**	**94,828**	**949,181**

2018-19 Customer Charge

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-19	S&T Aug-19
R-1	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.20	$ 15.20
R-3	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.20	$ 15.20
R-4	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.20	$ 15.20
G-41	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 56.36	$ 56.36
G-42	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 169.09	$ 169.09
G-43	$ 716.95	$ 716.95	$ 716.95	$ 716.95	$ 716.95	$ 716.95	$ 716.95	$ 716.95	$ 725.66	$ 725.66
G-51	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 56.36	$ 56.36
G-52	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 169.09	$ 169.09
G-53	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 746.81	$ 746.81
G-54	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 737.84	$ 746.81	$ 746.81

2018-19 Customer Revenue

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-19	S&T Aug-19	S&T Total
R-1	$ 52,451	$ 54,183	$ 54,237	$ 48,932	$ 54,202	$ 52,404	$ 54,158	$ 52,291	$ 54,337	$ 54,511	$ 531,706
R-3	$ 1,077,733	$ 1,118,817	$ 1,121,723	$ 1,015,408	$ 1,125,820	$ 1,088,293	$ 1,121,628	$ 1,082,561	$ 1,115,259	$ 1,113,383	$ 10,980,626
R-4	$ 89,344	$ 93,209	$ 93,275	$ 84,110	$ 92,684	$ 88,256	$ 89,469	$ 85,305	$ 87,820	$ 86,280	$ 889,752
Total Resid.	**$ 1,219,528**	**$ 1,266,209**	**$ 1,269,235**	**$ 1,148,451**	**$ 1,272,707**	**$ 1,228,953**	**$ 1,265,255**	**$ 1,220,157**	**$ 1,257,416**	**$ 1,254,174**	**$ 12,402,084**
G-41	$ 516,704	$ 539,197	$ 540,996	$ 490,224	$ 542,960	$ 522,584	$ 530,418	$ 503,568	$ 514,272	$ 513,073	$ 5,213,997
G-42	$ 231,832	$ 240,418	$ 240,749	$ 217,679	$ 240,952	$ 231,472	$ 238,317	$ 229,739	$ 245,475	$ 239,235	$ 2,355,869
G-43	$ 40,556	$ 43,304	$ 42,969	$ 38,811	$ 42,396	$ 40,269	$ 41,488	$ 40,197	$ 39,936	$ 40,516	$ 410,440
G-51	$ 71,870	$ 74,564	$ 74,618	$ 67,331	$ 74,547	$ 71,945	$ 73,937	$ 71,542	$ 71,094	$ 73,141	$ 724,589
G-52	$ 63,104	$ 65,238	$ 65,181	$ 58,861	$ 65,493	$ 63,728	$ 66,163	$ 64,122	$ 67,035	$ 66,091	$ 645,016
G-53	$ 27,300	$ 27,718	$ 27,447	$ 24,791	$ 26,095	$ 25,455	$ 26,587	$ 25,751	$ 28,553	$ 28,553	$ 268,250
G-54	$ 21,397	$ 22,110	$ 21,709	$ 19,954	$ 22,110	$ 20,782	$ 21,348	$ 20,659	$ 21,608	$ 21,608	$ 213,286
Total C/I	**$ 972,763**	**$ 1,012,550**	**$ 1,013,668**	**$ 917,652**	**$ 1,014,553**	**$ 976,236**	**$ 998,257**	**$ 955,579**	**$ 987,972**	**$ 982,217**	**$ 9,831,448**
Total All	**$ 2,192,291**	**$ 2,278,759**	**$ 2,282,903**	**$ 2,066,103**	**$ 2,287,260**	**$ 2,205,189**	**$ 2,263,512**	**$ 2,175,736**	**$ 2,245,388**	**$ 2,236,391**	**$ 22,233,532**

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the formula in the tariff

ENERGY COMPONENT

HEADBLOCK

2018-19 Decoupling Year Volume Headblock

	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T
1	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-18**	**Aug-18**	**Total**
R-1	66,792	87,822	99,362	85,620	83,304	65,051	51,933	39,449	32,291	32,765	644,390
R-3	6,221,642	9,273,573	10,904,070	9,354,740	7,899,041	4,508,297	2,467,008	1,285,515	990,721	989,518	53,894,124
R-4	491,772	735,019	873,656	741,408	632,293	360,273	194,913	104,523	79,984	78,607	4,292,449
Total Resid.	**6,780,206**	**10,096,414**	**11,877,089**	**10,181,768**	**8,614,637**	**4,933,621**	**2,713,854**	**1,429,487**	**1,102,997**	**1,100,890**	**58,830,964**
G-41	698,491	844,909	926,015	786,563	812,716	565,676	193,382	74,324	57,111	57,590	5,016,777
G-42	1,241,023	1,392,453	1,480,285	1,260,544	1,375,171	1,112,472	572,704	309,194	259,160	258,160	9,261,165
G-43	1,170,879	1,560,031	1,880,532	1,588,205	1,421,586	921,228	605,797	357,158	250,469	286,023	10,041,907
G-51	89,144	92,287	99,291	84,728	92,222	85,981	84,523	78,530	74,698	80,167	861,572
G-52	367,555	376,179	397,277	337,304	372,033	351,543	342,439	318,213	318,801	332,043	3,513,388
G-53	931,915	1,052,819	1,326,395	1,075,500	1,041,483	836,257	775,207	663,591	645,678	699,787	9,048,631
G-54	1,738,724	1,395,308	1,366,276	1,273,105	1,248,999	1,368,406	1,679,230	1,659,707	1,578,597	1,678,114	14,986,466
Total C/I	**6,237,730**	**6,713,985**	**7,476,072**	**6,405,948**	**6,364,211**	**5,241,563**	**4,253,283**	**3,460,715**	**3,184,514**	**3,391,883**	**52,729,905**
Total All	**13,017,936**	**16,810,400**	**19,353,161**	**16,587,717**	**14,978,848**	**10,175,185**	**6,967,137**	**4,890,202**	**4,287,510**	**4,492,773**	**111,560,869**

2018-19 Headblock Charge

	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T
	Nov-18	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**
R-1	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3786	$ 0.3786
R-3	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5569	$ 0.5569
R-4	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5569	$ 0.5569
G-41	$ 0.4566	$ 0.4566	$ 0.4566	$ 0.4566	$ 0.4566	$ 0.4566	$ 0.4566	$ 0.4566	$ 0.4621	$ 0.4621
G-42	$ 0.4152	$ 0.4152	$ 0.4152	$ 0.4152	$ 0.4152	$ 0.4152	$ 0.4152	$ 0.4152	$ 0.4202	$ 0.4202
G-43	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.1167	$ 0.1167	$ 0.1181	$ 0.1181
G-51	$ 0.2752	$ 0.2752	$ 0.2752	$ 0.2752	$ 0.2752	$ 0.2752	$ 0.2752	$ 0.2752	$ 0.2785	$ 0.2785
G-52	$ 0.2363	$ 0.2363	$ 0.2363	$ 0.2363	$ 0.2363	$ 0.2363	$ 0.1712	$ 0.1712	$ 0.1733	$ 0.1733
G-53	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.0792	$ 0.0792	$ 0.0802	$ 0.0802
G-54	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0342	$ 0.0342	$ 0.0346	$ 0.0346

2018-19 Decoupling Year Volume Headblock Revenue

	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T	S&T
	Nov-18	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Total**
R-1	$ 24,988	$ 32,856	$ 37,173	$ 32,032	$ 31,165	$ 24,337	$ 19,429	$ 14,759	$ 12,227	$ 12,406	$ 241,372
R-3	$ 3,422,977	$ 5,102,066	$ 5,999,121	$ 5,146,722	$ 4,345,836	$ 2,480,341	$ 1,357,280	$ 707,255	$ 551,719	$ 551,049	$ 29,664,365
R-4	$ 270,560	$ 404,388	$ 480,662	$ 407,903	$ 347,870	$ 198,212	$ 107,236	$ 57,505	$ 44,542	$ 43,775	$ 2,362,653
Total Resid.	**$ 3,718,524**	**$ 5,539,309**	**$ 6,516,956**	**$ 5,586,656**	**$ 4,724,871**	**$ 2,702,891**	**$ 1,483,945**	**$ 779,519**	**$ 608,488**	**$ 607,230**	**$ 32,268,390**
G-41	$ 318,926	$ 385,779	$ 422,812	$ 359,139	$ 371,080	$ 258,283	$ 88,297	$ 33,936	$ 26,394	$ 26,615	$ 2,291,261
G-42	$ 515,277	$ 578,151	$ 614,620	$ 523,383	$ 570,976	$ 461,902	$ 237,789	$ 128,378	$ 108,911	$ 108,490	$ 3,847,878
G-43	$ 298,807	$ 398,119	$ 479,911	$ 405,309	$ 362,788	$ 235,097	$ 70,695	$ 41,679	$ 29,585	$ 33,784	$ 2,355,774
G-51	$ 24,531	$ 25,396	$ 27,324	$ 23,316	$ 25,378	$ 23,661	$ 23,260	$ 21,610	$ 20,807	$ 22,330	$ 237,614
G-52	$ 86,861	$ 88,899	$ 93,885	$ 79,712	$ 87,920	$ 83,077	$ 58,629	$ 54,481	$ 55,242	$ 57,537	$ 746,244
G-53	$ 153,908	$ 173,876	$ 219,058	$ 177,622	$ 172,004	$ 138,110	$ 61,431	$ 52,586	$ 51,759	$ 56,097	$ 1,256,451
G-54	$ 109,526	$ 87,894	$ 86,065	$ 80,196	$ 78,677	$ 86,199	$ 57,466	$ 56,798	$ 54,644	$ 58,089	$ 755,554
Total C/I	**$ 1,507,838**	**$ 1,738,115**	**$ 1,943,674**	**$ 1,648,676**	**$ 1,668,823**	**$ 1,286,330**	**$ 597,566**	**$ 389,469**	**$ 347,342**	**$ 362,942**	**$ 11,490,775**
Total All	**$ 5,226,362**	**$ 7,277,424**	**$ 8,460,629**	**$ 7,235,332**	**$ 6,393,695**	**$ 3,989,221**	**$ 2,081,511**	**$ 1,168,988**	**$ 955,830**	**$ 970,173**	**$ 43,759,165**

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the formula in the tariff

TAILBLOCK

2018-19 Decoupling Year Volume Tailblock

2	**S&T Nov-18**	**S&T Dec-18**	**S&T Jan-19**	**S&T Feb-19**	**S&T Mar-19**	**S&T Apr-19**	**S&T May-19**	**S&T Jun-19**	**S&T Jul-18**	**S&T Aug-18**	**S&T Total**
R-1	-	-	-	-	-	-	-	-	-	-	-
R-3	-	-	-	-	-	-	-	-	-	-	-
R-4	-	-	-	-	-	-	-	-	-	-	-
Total Resid.	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
G-41	1,938,614	3,343,950	4,166,822	3,576,457	2,740,654	1,255,821	668,596	279,273	188,281	175,600	18,334,069
G-42	2,451,369	4,101,210	4,969,759	4,330,009	3,389,239	1,645,906	909,929	385,250	248,064	272,512	22,703,247
G-43	-	-	-	-	-	-	-	-	-	-	-
G-51	263,711	349,540	410,409	357,324	332,444	250,801	213,310	170,693	144,292	154,724	2,647,248
G-52	488,052	651,357	760,745	660,694	606,499	430,589	314,228	245,164	222,157	241,924	4,621,407
G-53	-	-	-	-	-	-	-	-	-	-	-
G-54	-	-	-	-	-	-	-	-	-	-	-
Total C/I	**5,141,746**	**8,446,056**	**10,307,734**	**8,924,483**	**7,068,836**	**3,583,117**	**2,106,064**	**1,080,380**	**802,794**	**844,759**	**48,305,971**
Total All	**5,141,746**	**8,446,056**	**10,307,734**	**8,924,483**	**7,068,836**	**3,583,117**	**2,106,064**	**1,080,380**	**802,794**	**844,759**	**48,305,971**

2018-19 Tailblock Charge

	S&T Nov-18	**S&T Dec-18**	**S&T Jan-19**	**S&T Feb-19**	**S&T Mar-19**	**S&T Apr-19**	**S&T May-19**	**S&T Jun-19**	**S&T Jul-19**	**S&T Aug-19**
R-1	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3741	$ 0.3786	$ 0.3786
R-3	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5502	$ 0.5569	$ 0.5569
R-4	$ 0.2201	$ 0.2201	$ 0.2201	$ 0.2201	$ 0.2201	$ 0.2201	$ 0.2201	$ 0.2201	$ 0.2228	$ 0.2228
G-41	$ 0.3067	$ 0.3067	$ 0.3067	$ 0.3067	$ 0.3067	$ 0.3067	$ 0.3067	$ 0.3067	$ 0.3104	$ 0.3104
G-42	$ 0.2766	$ 0.2766	$ 0.2766	$ 0.2766	$ 0.2766	$ 0.2766	$ 0.2766	$ 0.2766	$ 0.2800	$ 0.2800
G-43	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.2552	$ 0.1167	$ 0.1167	$ 0.1181	$ 0.1181
G-51	$ 0.1789	$ 0.1789	$ 0.1789	$ 0.1789	$ 0.1789	$ 0.1789	$ 0.1789	$ 0.1789	$ 0.1811	$ 0.1811
G-52	$ 0.1574	$ 0.1574	$ 0.1574	$ 0.1574	$ 0.1574	$ 0.1574	$ 0.0973	$ 0.0973	$ 0.0985	$ 0.0985
G-53	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.1652	$ 0.0792	$ 0.0792	$ 0.0802	$ 0.0802
G-54	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0630	$ 0.0342	$ 0.0342	$ 0.0346	$ 0.0346

2018-19 Decoupling Year Volume Tailblock Revenue

	S&T Nov-18	**S&T Dec-18**	**S&T Jan-19**	**S&T Feb-19**	**S&T Mar-19**	**S&T Apr-19**	**S&T May-19**	**S&T Jun-19**	**S&T Jul-19**	**S&T Aug-19**	**S&T Total**
R-1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
R-3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
R-4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Resid.	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
G-41	$ 594,541	$ 1,025,534	$ 1,277,895	$ 1,096,840	$ 840,513	$ 385,139	$ 205,047	$ 85,648	$ 58,448	$ 54,511	$ 5,624,116
G-42	$ 678,050	$ 1,134,397	$ 1,374,638	$ 1,197,683	$ 937,465	$ 455,258	$ 251,687	$ 106,560	$ 69,448	$ 76,293	$ 6,281,480
G-43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
G-51	$ 47,173	$ 62,526	$ 73,415	$ 63,919	$ 59,468	$ 44,864	$ 38,157	$ 30,534	$ 26,128	$ 28,017	$ 474,200
G-52	$ 76,809	$ 102,510	$ 119,726	$ 103,980	$ 95,451	$ 67,766	$ 30,579	$ 23,858	$ 21,879	$ 23,825	$ 666,383
G-53	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
G-54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total C/I	**$ 1,396,573**	**$ 2,324,967**	**$ 2,845,673**	**$ 2,462,421**	**$ 1,932,897**	**$ 953,028**	**$ 525,471**	**$ 246,601**	**$ 175,902**	**$ 182,645**	**$ 13,046,179**
Total All	**$ 1,396,573**	**$ 2,324,967**	**$ 2,845,673**	**$ 2,462,421**	**$ 1,932,897**	**$ 953,028**	**$ 525,471**	**$ 246,601**	**$ 175,902**	**$ 182,645**	**$ 13,046,179**

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Revenue Decoupling Adjustment Factor (RDAF)
Allowed Base Revenue based on the formula in the tariff

HEADBLOCK + TAILBLOCK

2018-19 Decoupling Year Volume Headblock + Tailblock

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-18	S&T Aug-18	S&T Total
R-1	66,792	87,822	99,362	85,620	83,304	65,051	51,933	39,449	32,291	32,765	644,390
R-3	6,221,642	9,273,573	10,904,070	9,354,740	7,899,041	4,508,297	2,467,008	1,285,515	990,721	989,518	53,894,124
R-4	491,772	735,019	873,656	741,408	632,293	360,273	194,913	104,523	79,984	78,607	4,292,449
Total Resid.	**6,780,206**	**10,096,414**	**11,877,089**	**10,181,768**	**8,614,637**	**4,933,621**	**2,713,854**	**1,429,487**	**1,102,997**	**1,100,890**	**58,830,964**
G-41	2,637,105	4,188,859	5,092,837	4,363,020	3,553,370	1,821,497	861,978	353,597	245,393	233,190	23,350,846
G-42	3,692,391	5,493,662	6,450,044	5,590,553	4,764,411	2,758,378	1,482,633	694,444	507,224	530,672	31,964,413
G-43	1,170,879	1,560,031	1,880,532	1,588,205	1,421,586	921,228	605,797	357,158	250,469	286,023	10,041,907
G-51	352,855	441,827	509,700	442,052	424,666	336,783	297,833	249,223	218,990	234,891	3,508,820
G-52	855,608	1,027,535	1,158,022	997,997	978,532	782,132	656,667	563,376	540,958	573,966	8,134,795
G-53	931,915	1,052,819	1,326,395	1,075,500	1,041,483	836,257	775,207	663,591	645,678	699,787	9,048,631
G-54	1,738,724	1,395,308	1,366,276	1,273,105	1,248,999	1,368,406	1,679,230	1,659,707	1,578,597	1,678,114	14,986,466
Total C/I	**11,379,477**	**15,160,041**	**17,783,806**	**15,330,432**	**13,433,046**	**8,824,681**	**6,359,347**	**4,541,096**	**3,987,308**	**4,236,643**	**101,035,876**
Total All	**18,159,682**	**25,256,456**	**29,660,895**	**25,512,200**	**22,047,684**	**13,758,302**	**9,073,201**	**5,970,583**	**5,090,305**	**5,337,533**	**159,866,840**

2018-19 Decoupling Year Volume Headblock + Tailblock Revenue

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-19	S&T Aug-19	S&T Total
R-1	$ 24,988	$ 32,856	$ 37,173	$ 32,032	$ 31,165	$ 24,337	$ 19,429	$ 14,759	$ 12,227	$ 12,406	$ 241,372
R-3	$ 3,422,977	$ 5,102,066	$ 5,999,121	$ 5,146,722	$ 4,345,836	$ 2,480,341	$ 1,357,280	$ 707,255	$ 551,719	$ 551,049	$ 29,664,365
R-4	$ 270,560	$ 404,388	$ 480,662	$ 407,903	$ 347,870	$ 198,212	$ 107,236	$ 57,505	$ 44,542	$ 43,775	$ 2,362,653
Total Resid.	**$ 3,718,524**	**$ 5,539,309**	**$ 6,516,956**	**$ 5,586,656**	**$ 4,724,871**	**$ 2,702,891**	**$ 1,483,945**	**$ 779,519**	**$ 608,488**	**$ 607,230**	**$ 32,268,390**
G-41	$ 913,467	$ 1,411,313	$ 1,700,707	$ 1,455,979	$ 1,211,593	$ 643,423	$ 293,344	$ 119,584	$ 84,842	$ 81,126	$ 7,915,378
G-42	$ 1,193,327	$ 1,712,548	$ 1,989,258	$ 1,721,065	$ 1,508,442	$ 917,161	$ 489,476	$ 234,939	$ 178,359	$ 184,783	$ 10,129,358
G-43	$ 298,807	$ 398,119	$ 479,911	$ 405,309	$ 362,788	$ 235,097	$ 70,695	$ 41,679	$ 29,585	$ 33,784	$ 2,355,774
G-51	$ 71,704	$ 87,923	$ 100,738	$ 87,235	$ 84,847	$ 68,525	$ 61,417	$ 52,144	$ 46,934	$ 50,346	$ 711,813
G-52	$ 163,671	$ 191,410	$ 213,611	$ 183,692	$ 183,370	$ 150,843	$ 89,208	$ 78,339	$ 77,120	$ 81,362	$ 1,412,626
G-53	$ 153,908	$ 173,876	$ 219,058	$ 177,622	$ 172,004	$ 138,110	$ 61,431	$ 52,586	$ 51,759	$ 56,097	$ 1,256,451
G-54	$ 109,526	$ 87,894	$ 86,065	$ 80,196	$ 78,677	$ 86,199	$ 57,466	$ 56,798	$ 54,644	$ 58,089	$ 755,554
Total C/I	**$ 2,904,411**	**$ 4,063,082**	**$ 4,789,347**	**$ 4,111,097**	**$ 3,601,720**	**$ 2,239,358**	**$ 1,123,037**	**$ 636,070**	**$ 523,244**	**$ 545,588**	**$ 24,536,954**
Total All	**$ 6,622,935**	**$ 9,602,391**	**$ 11,306,303**	**$ 9,697,754**	**$ 8,326,592**	**$ 4,942,248**	**$ 2,606,982**	**$ 1,415,589**	**$ 1,131,732**	**$ 1,152,818**	**$ 56,805,344**

TOTAL REVENUE

2018-19 Decoupling Year Base Revenue

	S&T Nov-18	S&T Dec-18	S&T Jan-19	S&T Feb-19	S&T Mar-19	S&T Apr-19	S&T May-19	S&T Jun-19	S&T Jul-19	S&T Aug-19	S&T Total
R-1	$ 77,439	$ 87,039	$ 91,410	$ 80,964	$ 85,368	$ 76,741	$ 73,587	$ 67,049	$ 66,563	$ 66,917	$ 773,078
R-3	$ 4,500,710	$ 6,220,883	$ 7,120,844	$ 6,162,130	$ 5,471,656	$ 3,568,634	$ 2,478,908	$ 1,789,816	$ 1,666,978	$ 1,664,432	$ 40,644,991
R-4	$ 359,903	$ 497,596	$ 573,936	$ 492,013	$ 440,554	$ 286,468	$ 196,705	$ 142,811	$ 132,362	$ 130,055	$ 3,252,404
Total Resid.	**$ 4,938,052**	**$ 6,805,518**	**$ 7,786,191**	**$ 6,735,107**	**$ 5,997,578**	**$ 3,931,843**	**$ 2,749,200**	**$ 1,999,677**	**$ 1,865,904**	**$ 1,861,404**	**$ 44,670,474**
G-41	$ 1,430,171	$ 1,950,510	$ 2,241,703	$ 1,946,203	$ 1,754,553	$ 1,166,007	$ 823,762	$ 623,152	$ 599,114	$ 594,200	$ 13,129,375
G-42	$ 1,425,159	$ 1,952,967	$ 2,230,006	$ 1,938,744	$ 1,749,393	$ 1,148,633	$ 727,793	$ 464,678	$ 423,835	$ 424,018	$ 12,485,227
G-43	$ 339,363	$ 441,423	$ 522,880	$ 444,120	$ 405,183	$ 275,366	$ 112,182	$ 81,876	$ 69,520	$ 74,301	$ 2,766,214
G-51	$ 143,575	$ 162,487	$ 175,356	$ 154,566	$ 159,394	$ 140,470	$ 135,354	$ 123,686	$ 118,028	$ 123,487	$ 1,436,403
G-52	$ 226,775	$ 256,647	$ 278,792	$ 242,553	$ 248,864	$ 214,572	$ 155,371	$ 142,461	$ 144,155	$ 147,453	$ 2,057,643
G-53	$ 181,208	$ 201,594	$ 246,505	$ 202,413	$ 198,099	$ 163,565	$ 88,018	$ 78,337	$ 80,312	$ 84,650	$ 1,524,700
G-54	$ 130,923	$ 110,004	$ 107,773	$ 100,150	$ 100,788	$ 106,981	$ 78,814	$ 77,458	$ 76,252	$ 79,697	$ 968,840
Total C/I	**$ 3,877,174**	**$ 5,075,631**	**$ 5,803,015**	**$ 5,028,749**	**$ 4,616,274**	**$ 3,215,593**	**$ 2,121,294**	**$ 1,591,649**	**$ 1,511,216**	**$ 1,527,805**	**$ 34,368,401**
Total All	**$ 8,815,226**	**$ 11,881,150**	**$ 13,589,206**	**$ 11,763,856**	**$ 10,613,852**	**$ 7,147,437**	**$ 4,870,494**	**$ 3,591,326**	**$ 3,377,119**	**$ 3,389,209**	**$ 79,038,875**

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Rates effective November 1, 2019 - April 30, 2020 ~~Rates effective April 1, 2019 - April 30, 2019~~ **Winter Period**				Rates Effective May 1, 2020 - October 31, 2020 ~~Rates Effective Septmber 1, 2018 - October 31, 2018~~ **Summer Period**			
	Delivery Charge	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**
Residential Non Heating - R-1	~~$ 15.02~~			~~$ 15.02~~	~~$ 15.02~~			~~$ 15.02~~
Customer Charge per Month per Meter	$ 15.20			$ 15.20	$ 15.20			$ 15.20
All Therms	$ 0.3786	$ 0.6203	$ 0.0310	$ 1.0299	$ 0.3786	$ 0.4520	$ 0.0310	$ 0.8616
	~~$ 0.3741~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.0226~~	~~$ 0.3938~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.8799~~
Residential Heating - R-3	~~$ 15.02~~			~~$ 15.02~~	~~$ 15.02~~			~~$ 15.02~~
Customer Charge per Month per Meter	$ 15.20			$ 15.20	$ 15.20			$ 15.20
Size of the first block	all therms				all therms			
Therms in the first block per month at	$ 0.5569	$ 0.6203	$ 0.0310	$ 1.2082	$ 0.5569	$ 0.4520	$ 0.0310	$ 1.0399
	~~$ 0.5502~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.1987~~	~~$ 0.5631~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 1.0492~~
Residential Heating - R-4	~~$ 6.01~~			~~$ 6.01~~	~~$ 6.00~~			~~$ 6.00~~
Customer Charge per Month per Meter	$ 6.08			$ 6.08	$ 6.08			$ 6.08
Size of the first block	all therms				20 therms			
Therms in the first block per month at	$ 0.2228	$ 0.6203	$ 0.0310	$ 0.8740	$ 0.2228	$ 0.4520	$ 0.0310	$ 0.7058
	~~$ 0.2201~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 0.8686~~	~~$ 0.2252~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.7113~~
Commercial/Industrial - G-41	~~$ 55.68~~			~~$ 55.68~~	~~$ 56.58~~			~~$ 56.58~~
Customer Charge per Month per Meter	$ 56.36			$ 56.36	$ 56.36			$ 56.36
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.4621	$ 0.6190	$ 0.0478	$ 1.1290	$ 0.4621	$ 0.4474	$ 0.0478	$ 0.9573
	~~$ 0.4566~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.1140~~	~~$ 0.4639~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.9257~~
All therms over the first block per month at	$ 0.3104	$ 0.6190	$ 0.0478	$ 0.9773	$ 0.3104	$ 0.4474	$ 0.0478	$ 0.8056
	~~$ 0.3067~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9641~~	~~$ 0.3116~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.7734~~
Commercial/Industrial - G-42	~~$ 167.06~~			~~$ 167.06~~	~~$ 169.75~~			~~$ 169.75~~
Customer Charge per Month per Meter	$ 169.09			$ 169.09	$ 169.09			$ 169.09
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4202	$ 0.6190	$ 0.0478	$ 1.0871	$ 0.4202	$ 0.4474	$ 0.0478	$ 0.9154
	~~$ 0.4152~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.0726~~	~~$ 0.4219~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.8837~~
All therms over the first block per month at	$ 0.2800	$ 0.6190	$ 0.0478	$ 0.9468	$ 0.2800	$ 0.4474	$ 0.0478	$ 0.7752
	~~$ 0.2766~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9340~~	~~$ 0.2811~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.7429~~
Commercial/Industrial - G-43	~~$ 716.95~~			~~$ 716.95~~	~~$ 728.47~~			~~$ 728.47~~
Customer Charge per Month per Meter	$ 725.66			$ 725.66	$ 725.66			$ 725.66
All therms over the first block per month at	$ 0.2583	$ 0.6190	$ 0.0478	$ 0.9251	$ 0.1181	$ 0.4474	$ 0.0478	$ 0.6133
	~~$ 0.2552~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9126~~	~~$ 0.1185~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.5803~~
Commercial/Industrial - G-51	~~$ 55.68~~			~~$ 55.68~~	~~$ 56.58~~			~~$ 56.58~~
Customer Charge per Month per Meter	$ 56.36			$ 56.36	$ 56.36			$ 56.36
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.2785	$ 0.6258	$ 0.0478	$ 0.9522	$ 0.2785	$ 0.4591	$ 0.0478	$ 0.7854
	~~$ 0.2752~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.9379~~	~~$ 0.2796~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.7683~~
All therms over the first block per month at	$ 0.1811	$ 0.6258	$ 0.0478	$ 0.8547	$ 0.1811	$ 0.4591	$ 0.0478	$ 0.6880
	~~$ 0.1789~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8416~~	~~$ 0.1817~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.6704~~
Commercial/Industrial - G-52	~~$ 167.06~~			~~$ 167.06~~	~~$ 169.75~~			~~$ 169.75~~
Customer Charge per Month per Meter	$ 169.09			$ 169.09	$ 169.09			$ 169.09
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2392	$ 0.6258	$ 0.0478	$ 0.9128	$ 0.1733	$ 0.4591	$ 0.0478	$ 0.6802
	~~$ 0.2363~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8990~~	~~$ 0.1740~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.6627~~
All therms over the first block per month at	$ 0.1593	$ 0.6258	$ 0.0478	$ 0.8329	$ 0.0985	$ 0.4591	$ 0.0478	$ 0.6054
	~~$ 0.1574~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8201~~	~~$ 0.0989~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5876~~
Commercial/Industrial - G-53	~~$ 737.84~~			~~$ 737.84~~	~~$ 749.68~~			~~$ 749.68~~
Customer Charge per Month per Meter	$ 746.81			$ 746.81	$ 746.81			$ 746.81
All therms over the first block per month at	$ 0.1672	$ 0.6258	$ 0.0478	$ 0.8408	$ 0.0802	$ 0.4591	$ 0.0478	$ 0.5871
	~~$ 0.1652~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8279~~	~~$ 0.0805~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5692~~
Commercial/Industrial - G-54	~~$ 737.84~~			~~$ 737.84~~	~~$ 749.68~~			~~$ 749.68~~
Customer Charge per Month per Meter	$ 746.81			$ 746.81	$ 746.81			$ 746.81
All therms over the first block per month at	$ 0.0638	$ 0.6258	$ 0.0478	$ 0.7374	$ 0.0346	$ 0.4591	$ 0.0478	$ 0.5415
	~~$ 0.0630~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.7257~~	~~$ 0.0347~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5234~~

Issued: ~~October xx, 2018~~ October xx, 2019

Effective: ~~November 1, 2018~~ November 1, 2019

Issued by: ______________________
Susan L. Fleck

Title: President

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NHPUC NO. 10 - GAS **Revised Proposed Fifteenth Revised Page 86**
LIBERTY UTILITIES **Superseding Sixth Revised Page 86**

	Rates effective November 1, 2019 - April 30, 2020 ~~Rates effective April 1, 2019 - April 30, 2019~~ **Winter Period**				Rates Effective May 1, 2020 - October 31, 2020 ~~Rates Effective Septmber 1, 2018 - October 31, 2018~~ **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**
Residential Non Heating - R-5	~~$ 19.53~~			~~$ 19.53~~	~~$ 19.52~~			~~$ 19.52~~
Customer Charge per Month per Meter	$ 19.76			$ 19.76	$ 19.76			$ 19.76
All therms	$ 0.4922	$ 0.6203	$ 0.0310	$ 1.1435	$ 0.4922	$ 0.4520	$ 0.0310	$ 0.9752
	~~$ 0.4863~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.1348~~	~~$ 0.5119~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.9980~~
Residential Heating - R-6	~~$ 19.53~~			~~$ 19.53~~	~~$ 19.52~~			~~$ 19.52~~
Customer Charge per Month per Meter	$ 19.76			$ 19.76	$ 19.76			$ 19.76
All therms	$ 0.7240	$ 0.6203	$ 0.0310	$ 1.3752	$ 0.7240	$ 0.4520	$ 0.0310	$ 1.2069
	~~$ 0.7153~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 1.3638~~	~~$ 0.7320~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 1.2181~~
Residential Heating - R-7	~~$ 7.81~~			~~$ 7.81~~	~~$ 7.81~~			~~$ 7.81~~
Customer Charge per Month per Meter	$ 7.90			$ 7.90	$ 7.90			$ 7.90
All therms	$ 0.2896	$ 0.6203	$ 0.0310	$ 0.9409	$ 0.2896	$ 0.4520	$ 0.0310	$ 0.7726
	~~$ 0.2861~~	~~$ 0.5825~~	~~$ 0.0660~~	~~$ 0.9346~~	~~$ 0.2928~~	~~$ 0.3916~~	~~$ 0.0945~~	~~$ 0.7789~~
Commercial/Industrial - G-44	~~$ 72.38~~			~~$ 72.38~~	~~$ 73.56~~			~~$ 73.56~~
Customer Charge per Month per Meter	$ 73.26			$ 73.26	$ 73.26			$ 73.26
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.6008	$ 0.6190	$ 0.0478	$ 1.2676	$ 0.5463	$ 0.4474	$ 0.0478	$ 1.0415
	~~$ 0.5936~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.2510~~	~~$ 0.6031~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 1.0649~~
All therms over the first block per month a	$ 0.4036	$ 0.6190	$ 0.0478	$ 1.0704	$ 0.3639	$ 0.4474	$ 0.0478	$ 0.8591
	~~$ 0.3987~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.0561~~	~~$ 0.4051~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.8669~~
Commercial/Industrial - G-45	~~$ 217.18~~			~~$ 217.18~~	~~$ 220.68~~			~~$ 220.68~~
Customer Charge per Month per Meter	$ 219.82			$ 219.82	$ 219.82			$ 219.82
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.5463	$ 0.6190	$ 0.0478	$ 1.2131	$ 0.5463	$ 0.4474	$ 0.0478	$ 1.0415
	~~$ 0.5398~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.1972~~	~~$ 0.5485~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 1.0103~~
All therms over the first block per month a	$ 0.3639	$ 0.6190	$ 0.0478	$ 1.0308	$ 0.3639	$ 0.4474	$ 0.0478	$ 0.8591
	~~$ 0.3596~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 1.0170~~	~~$ 0.3654~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.8272~~
Commercial/Industrial - G-46	~~$ 932.04~~			~~$ 932.04~~	~~$ 947.01~~			~~$ 947.01~~
Customer Charge per Month per Meter	$ 943.36			$ 943.36	$ 943.36			$ 943.36
All therms over the first block per month a	$ 0.3358	$ 0.6190	$ 0.0478	$ 1.0026	$ 0.1535	$ 0.4474	$ 0.0478	$ 0.6487
	~~$ 0.3318~~	~~$ 0.5817~~	~~$ 0.0757~~	~~$ 0.9892~~	~~$ 0.1540~~	~~$ 0.3855~~	~~$ 0.0763~~	~~$ 0.6158~~
Commercial/Industrial - G-55	~~$ 72.38~~			~~$ 72.38~~	~~$ 73.56~~			~~$ 73.56~~
Customer Charge per Month per Meter	$ 73.26			$ 73.26	$ 73.26			$ 73.26
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.3621	$ 0.6258	$ 0.0478	$ 1.0357	$ 0.3621	$ 0.4591	~~$ 0.0763~~	$ 0.8975
	~~$ 0.3578~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 1.0205~~	~~$ 0.3635~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.8522~~
All therms over the first block per month a	$ 0.2354	$ 0.6258	$ 0.0478	$ 0.9090	$ 0.2354	$ 0.4591	$ 0.0478	$ 0.7423
	~~$ 0.2326~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8953~~	~~$ 0.2363~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.7250~~
Commercial/Industrial - G-56	~~$ 217.18~~			~~$ 217.18~~	~~$ 220.68~~			~~$ 220.68~~
Customer Charge per Month per Meter	$ 219.82			$ 219.82	$ 219.82			$ 219.82
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.3109	$ 0.6258	$ 0.0478	$ 0.9846	$ 0.2253	$ 0.4591	$ 0.0478	$ 0.7322
	~~$ 0.3072~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.9699~~	~~$ 0.2262~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.7149~~
All therms over the first block per month a	$ 0.2071	$ 0.6258	$ 0.0478	$ 0.8807	$ 0.1280	$ 0.4591	$ 0.0478	$ 0.6349
	~~$ 0.2046~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8673~~	~~$ 0.1286~~			
Commercial/Industrial - G-57	~~$ 959.19~~			~~$ 959.19~~	~~$ 974.59~~			~~$ 974.59~~
Customer Charge per Month per Meter	$ 970.84			$ 970.84	$ 970.84			$ 970.84
All therms over the first block per month a	$ 0.2174	$ 0.6258	$ 0.0478	$ 0.8910	$ 0.1043	$ 0.4591	$ 0.0478	$ 0.6112
	~~$ 0.2148~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.8775~~	~~$ 0.1047~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5934~~
Commercial/Industrial - G-58	~~$ 959.19~~			~~$ 959.19~~	~~$ 974.59~~			~~$ 974.59~~
Customer Charge per Month per Meter	$ 970.84			$ 970.84	$ 970.84			$ 970.84
All therms over the first block per month a	$ 0.0829	$ 0.6258	$ 0.0478	$ 0.7565	$ 0.0450	$ 0.4591	$ 0.0478	$ 0.5519
	~~$ 0.0819~~	~~$ 0.5870~~	~~$ 0.0757~~	~~$ 0.7446~~	~~$ 0.0451~~	~~$ 0.4124~~	~~$ 0.0763~~	~~$ 0.5338~~

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2020 Summer Cost of Gas Filing
Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Residential Heating Rate R-3

November 1, 2019 - April 30, 2020 / **May 1, 2020 - October 31, 2020**
Residential Heating (R3)

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Winter Nov-Apr	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		62	110	123	148	132	92	666	51	28	16	14	14	21	142	809
	7/1/2019															
Winter:																
Cust. Chg	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 91.20								
Headblock	$ 0.5569	$ -	$ -	$ -	$ -	$ -	$ -	$ -								
Tailblock	$ 0.5569	$ 34.35	$ 61.12	$ 68.38	$ 82.21	$ 73.78	$ 51.15	$ 370.99								
HB Threshold	-															
Summer:																
Cust. Chg	$ 15.20								$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 91.20	$ 182.40
Headblock	$ 0.5569								$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.5569								$ 28.31	$ 15.51	$ 8.85	$ 7.56	$ 7.65	$ 11.47	$ 79.35	$ 450.34
HB Threshold	-															
Total Base Rate Amount		$ 49.55	$ 76.32	$ 83.58	$ 97.41	$ 88.98	$ 66.35	$ 462.19	$ 43.51	$ 30.71	$ 24.05	$ 22.76	$ 22.85	$ 26.67	$ 170.55	$ 632.74
COG Rate - (Seasonal)		$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.6203	$ 0.4520	$ 0.4520	$ 0.4520	$ 0.4520	$ 0.4520	$ 0.4520	$ 0.4520	$ 0.5906
COG amount		$ 38.26	$ 68.07	$ 76.17	$ 91.57	$ 82.17	$ 56.98	$ 413.23	$ 22.97	$ 12.59	$ 7.18	$ 6.14	$ 6.21	$ 9.31	$ 64.41	$ 477.63
LDAC		$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310
LDAC amount		$ 1.91	$ 3.40	$ 3.80	$ 4.57	$ 4.10	$ 2.84	$ 20.63	$ 1.57	$ 0.86	$ 0.49	$ 0.42	$ 0.43	$ 0.64	$ 4.41	$ 25.04
Total Bill		**$ 89.73**	**$ 147.79**	**$ 163.55**	**$ 193.55**	**$ 175.25**	**$ 126.18**	**$ 896.05**	**$ 68.06**	**$ 44.15**	**$ 31.73**	**$ 29.32**	**$ 29.49**	**$ 36.62**	**$ 239.37**	**$ 1,135.42**

November 1, 2018 - April 30, 2019 / **May 1, 2019 - October 31, 2019**
Residential Heating (R3)

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		62	110	123	148	132	92	666	51	28	16	14	14	21	142	809
Winter:																
Cust. Chg		$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 15.02	$ 90.12								
Headblock		$ -	$ -	$ -	$ -	$ -	$ -	$ -								
Tailblock		$ 33.94	$ 60.38	$ 67.56	$ 81.22	$ 72.89	$ 50.54	$ 366.53								
HB Threshold																
Summer:																
Cust. Chg									$ 15.02	$ 15.02	$ 15.20	$ 15.20	$ 15.20	$ 15.20	$ 90.84	$ 180.96
Headblock									$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock									$ 27.97	$ 15.32	$ 8.85	$ 7.56	$ 7.65	$ 11.47	$ 78.83	$ 445.35
HB Threshold																
Total Base Rate Amount		$ 48.96	$ 75.40	$ 82.58	$ 96.24	$ 87.91	$ 65.56	$ 456.65	$ 42.99	$ 30.34	$ 24.05	$ 22.76	$ 22.85	$ 26.67	$ 169.67	$ 626.31
COG Rate - (Seasonal)		$ 0.7411	$ 0.7504	$ 0.7504	$ 0.8056	$ 0.8056	$ 0.8056	$ 0.7804	$ 0.4445	$ 0.4445	$ 0.5556	$ 0.5556	$ 0.5556	$ 0.5556	$ 0.4943	$ 0.7299
COG amount		$ 45.72	$ 82.35	$ 92.14	$ 118.92	$ 106.72	$ 74.00	$ 519.85	$ 22.59	$ 12.38	$ 8.83	$ 7.54	$ 7.64	$ 11.45	$ 70.43	$ 590.28
LDAC		$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0660	$ 0.0945	$ 0.0945	$ 0.0945	$ 0.0945	$ 0.0945	$ 0.0945	$ 0.0945	$ 0.0710
LDAC amount		$ 4.07	$ 7.24	$ 8.10	$ 9.74	$ 8.74	$ 6.06	$ 43.97	$ 4.80	$ 2.63	$ 1.50	$ 1.28	$ 1.30	$ 1.95	$ 13.47	$ 57.43
Total Bill		**$ 98.75**	**$ 165.00**	**$ 182.82**	**$ 224.90**	**$ 203.37**	**$ 145.62**	**$ 1,020.47**	**$ 70.38**	**$ 45.35**	**$ 34.38**	**$ 31.59**	**$ 31.79**	**$ 40.07**	**$ 253.56**	**$ 1,274.03**

DIFFERENCE:

Total Bill	**$ (9.02)**	**$ (17.21)**	**$ (19.27)**	**$ (31.36)**	**$ (28.12)**	**$ (19.44)**	**$ (124.42)**	**$ (2.33)**	**$ (1.19)**	**$ (2.66)**	**$ (2.27)**	**$ (2.30)**	**$ (3.44)**	**$ (14.19)**	**$ (138.61)**
% Change	**-9.13%**	**-10.43%**	**-10.54%**	**-13.94%**	**-13.83%**	**-13.35%**	**-12.19%**	**-3.31%**	**-2.63%**	**-7.73%**	**-7.18%**	**-7.23%**	**-8.59%**	**-5.60%**	**-10.88%**
Base Rate	$ 0.59	$ 0.92	$ 1.00	$ 1.17	$ 1.07	$ 0.80	$ 5.54	$ 0.52	$ 0.37	$ -	$ -	$ -	$ -	$ 0.89	$ 6.43
% Change	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	0.00%	0.00%	0.00%	0.00%	0.52%	1.03%
COG & LDAC	$ (9.61)	$ (18.12)	$ (20.28)	$ (32.52)	$ (29.19)	$ (20.24)	$ (129.96)	$ (2.85)	$ (1.56)	$ (2.66)	$ (2.27)	$ (2.30)	$ (3.44)	$ (15.07)	$ (145.04)
% Change	-19.31%	-20.23%	-20.23%	-25.28%	-25.28%	-25.28%	-23.05%	-10.40%	-10.40%	-25.71%	-25.71%	-25.71%	-25.71%	-17.97%	-22.39%
check	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.00	$ -	$ -	$ -	$ 0.00	$ 0.00	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2020 Summer Cost of Gas Filing
Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-41

November 1, 2019 - April 30, 2020
Commercial Rate (G-41)

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Winter Nov-Apr
Typical Usage (Therms)		89	277	504	457	331	297	1,954
Winter:	7/1/2019							
Cust. Chg	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 338.16
Headblock	$ 0.4621	$ 40.99	$ 46.21	$ 46.21	$ 46.21	$ 46.21	$ 46.21	$ 272.04
Tailblock	$ 0.3104	$ -	$ 54.98	$ 125.36	$ 110.70	$ 71.65	$ 61.09	$ 423.78
HB Threshold	100							
Summer:								
Cust. Chg	$ 56.36							
Headblock	$ 0.4621							
Tailblock	$ 0.3104							
HB Threshold	20							
Total Base Rate Amount		$ 97.35	$ 157.55	$ 227.93	$ 213.27	$ 174.22	$ 163.66	$ 1,033.97
COG Rate - (Seasonal)		$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190
COG amount		$ 54.91	$ 171.54	$ 311.89	$ 282.65	$ 204.78	$ 183.73	$ 1,209.50
LDAC		$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
LDAC amount		$ 4.24	$ 13.26	$ 24.10	$ 21.84	$ 15.82	$ 14.20	$ 93.46
Total Bill		**$ 156.50**	**$ 342.35**	**$ 563.91**	**$ 517.75**	**$ 394.83**	**$ 361.59**	**$ 2,336.93**

May 1, 2020 - October 31, 2020

	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	153	39	26	34	25	29	306	2,260
Cust. Chg	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 338.16	$ 676.32
Headblock	$ 9.24	$ 9.24	$ 9.24	$ 9.24	$ 9.24	$ 9.24	$ 55.45	$ 327.49
Tailblock	$ 41.20	$ 5.81	$ 1.95	$ 4.21	$ 1.57	$ 2.86	$ 57.61	$ 481.38
Total Base Rate Amount	$ 106.81	$ 71.42	$ 67.55	$ 69.81	$ 67.17	$ 68.46	$ 451.22	$ 1,485.19
COG Rate - (Seasonal)	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.5958
COG amount	$ 68.34	$ 17.33	$ 11.76	$ 15.02	$ 11.21	$ 13.07	$ 136.72	$ 1,346.22
LDAC	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
LDAC amount	$ 7.31	$ 1.85	$ 1.26	$ 1.61	$ 1.20	$ 1.40	$ 14.62	$ 108.07
Total Bill	**$ 182.45**	**$ 90.59**	**$ 80.56**	**$ 86.44**	**$ 79.59**	**$ 82.93**	**$ 602.56**	**$ 2,939.49**

November 1, 2018 - April 30, 2019
Commercial Rate (G-41)

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr
Typical Usage (Therms)	89	277	504	457	331	297	1,954
Winter:							
Cust. Chg	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 55.68	$ 334.08
Headblock	$ 40.50	$ 45.66	$ 45.66	$ 45.66	$ 45.66	$ 45.66	$ 268.80
Tailblock	$ -	$ 54.33	$ 123.86	$ 109.38	$ 70.80	$ 60.37	$ 418.72
HB Threshold							
Summer:							
Cust. Chg							
Headblock							
Tailblock							
HB Threshold							
Total Base Rate Amount	$ 96.18	$ 155.67	$ 225.20	$ 210.72	$ 172.14	$ 161.71	$ 1,021.60
COG Rate - (Seasonal)	$ 0.7403	$ 0.7403	$ 0.7496	$ 0.6707	$ 0.5204	$ 0.5817	$ 0.6651
COG amount	$ 65.67	$ 205.16	$ 377.69	$ 306.26	$ 172.16	$ 172.66	$ 1,299.59
LDAC	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
LDAC amount	$ 6.71	$ 20.98	$ 38.14	$ 34.57	$ 25.04	$ 22.47	$ 147.91
Total Bill	**$ 168.56**	**$ 381.80**	**$ 641.04**	**$ 551.54**	**$ 369.34**	**$ 356.84**	**$ 2,469.11**

May 1, 2019 - October 31, 2019

	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	153	39	26	34	25	29	306	2,260
Cust. Chg	$ 55.68	$ 55.68	$ 56.36	$ 56.36	$ 56.36	$ 56.36	$ 336.80	$ 670.88
Headblock	$ 9.13	$ 9.13	$ 9.24	$ 9.24	$ 9.24	$ 9.24	$ 55.23	$ 324.03
Tailblock	$ 40.71	$ 5.74	$ 1.95	$ 4.21	$ 1.57	$ 2.86	$ 57.05	$ 475.77
Total Base Rate Amount	$ 105.52	$ 70.56	$ 67.55	$ 69.81	$ 67.17	$ 68.46	$ 449.08	$ 1,470.68
COG Rate - (Seasonal)	$ 0.4417	$ 0.4417	$ 0.5517	$ 0.5517	$ 0.5517	$ 0.5517	$ 0.4828	$ 0.6404
COG amount	$ 67.47	$ 17.11	$ 14.50	$ 18.52	$ 13.83	$ 16.12	$ 147.53	$ 1,447.13
LDAC	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
LDAC amount	$ 11.56	$ 2.93	$ 1.99	$ 2.54	$ 1.90	$ 2.21	$ 23.13	$ 171.05
Total Bill	**$ 184.55**	**$ 90.59**	**$ 84.03**	**$ 90.87**	**$ 82.90**	**$ 86.79**	**$ 619.74**	**$ 3,088.86**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
Total Bill	**$ (12.06)**	**$ (39.45)**	**$ (77.12)**	**$ (33.78)**	**$ 25.48**	**$ 4.76**	**$ (132.18)**
% Change	**-7.16%**	**-10.33%**	**-12.03%**	**-6.13%**	**6.90%**	**1.33%**	**-5.35%**
Base Rate	$ 1.17	$ 1.89	$ 2.72	$ 2.55	$ 2.08	$ 1.96	$ 12.37
% Change	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%	1.21%
COG & LDAC	$ (13.23)	$ (41.34)	$ (79.85)	$ (36.33)	$ 23.40	$ 2.80	$ (144.55)
% Change	-18.28%	-18.28%	-19.20%	-10.66%	11.87%	1.43%	-9.99%
check	$ -	$ -	$ -	$ -	$ (0.00)	$ (0.00)	

	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$ (2.11)**	**$ 0.00**	**$ (3.47)**	**$ (4.44)**	**$ (3.31)**	**$ (3.86)**	**$ (17.19)**	**$ (149.37)**
% Change	**-1.14%**	**0.00%**	**-4.13%**	**-4.88%**	**-4.00%**	**-4.45%**	**-2.77%**	**-4.84%**
Base Rate	$ 1.28	$ 0.86	$ -	$ -	$ -	$ -	$ 2.14	$ 14.51
% Change	1.21%	1.22%	0.00%	0.00%	0.00%	0.00%	0.48%	0.99%
COG & LDAC	$ (3.39)	$ (0.86)	$ (3.47)	$ (4.44)	$ (3.31)	$ (3.86)	$ (19.33)	$ (163.88)
% Change	-4.28%	-4.28%	-21.07%	-21.07%	-21.07%	-21.07%	-11.33%	-10.13%
check	$ 0.00	$ (0.00)	$ 0.00	$ -	$ (0.00)	$ 0.00	$ (0.00)	$ (0.00)

Liberty Utilities (EnergyNorth Natural Gas) Corp.

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2 **Off Peak 2020 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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6

7 **November 1, 2019 - April 30, 2020** | **May 1, 2020 - October 31, 2020**

8 **C&I High Winter Use Medium G-42**

Ln	Item	Rate	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Winter Nov-Apr	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Summer May-Oct	Total Nov-Oct
9																	
10																	
11	**Typical Usage (Therms)**		830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
12		7/1/2019															
13	**Winter:**																
14	Cust. Chg	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,014.54								
15	Headblock	$ 0.4202	$ 348.79	$ 420.20	$ 420.20	$ 420.20	$ 420.20	$ 420.20	$ 2,449.79								
16	Tailblock	$ 0.2800	$ -	$ 332.82	$ 758.10	$ 673.62	$ 448.79	$ 390.57	$ 2,603.90								
17	HB Threshold	1,000															
18																	
19	**Summer:**																
20	Cust. Chg	$ 169.09								$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,014.54	$ 2,029.08
21	Headblock	$ 0.4202								$ 168.08	$ 168.08	$ 119.59	$ 103.61	$ 112.86	$ 143.03	$ 815.24	$ 3,265.04
22	Tailblock	$ 0.2800								$ 257.32	$ 23.55	$ -	$ -	$ -	$ -	$ 280.87	$ 2,884.77
23	HB Threshold	400															
24																	
25	Total Base Rate Amount		$ 517.88	$ 922.11	$ 1,347.39	$ 1,262.91	$ 1,038.08	$ 979.86	$ 6,068.23	$ 594.49	$ 360.72	$ 288.68	$ 272.70	$ 281.95	$ 312.12	$ 2,110.65	$ 8,178.88
26																	
27	COG Rate - (Seasonal)		$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.6190	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.4474	$ 0.5911
28	COG amount		$ 513.81	$ 1,354.77	$ 2,294.95	$ 2,108.18	$ 1,611.14	$ 1,482.44	$ 9,365.28	$ 590.12	$ 216.58	$ 127.33	$ 110.32	$ 120.16	$ 152.29	$ 1,316.80	$ 10,682.09
29																	
30	LDAC		$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
31	LDAC amount		$ 39.70	$ 104.68	$ 177.33	$ 162.90	$ 124.49	$ 114.55	$ 723.66	$ 63.09	$ 23.15	$ 13.61	$ 11.79	$ 12.85	$ 16.28	$ 140.78	$ 864.43
32																	
33	**Total Bill**		**$ 1,071.39**	**$ 2,381.56**	**$ 3,819.67**	**$ 3,533.99**	**$ 2,773.71**	**$ 2,576.85**	**$ 16,157.17**	**$ 1,247.71**	**$ 600.45**	**$ 429.61**	**$ 394.82**	**$ 414.95**	**$ 480.69**	**$ 3,568.23**	**$ 19,725.40**

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35 **November 1, 2018 - April 30, 2019** | **May 1, 2019 - October 31, 2019**

36 **C&I High Winter Use Medium G-42**

Ln	Item	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Summer May-Oct	Total Nov-Oct
37																
38																
39	**Typical Usage (Therms)**	830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
40																
41	**Winter:**															
42	Cust. Chg	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 1,002.36								
43	Headblock	$ 344.64	$ 415.20	$ 415.20	$ 415.20	$ 415.20	$ 415.20	$ 2,420.64								
44	Tailblock	$ -	$ 328.78	$ 748.90	$ 665.44	$ 443.34	$ 385.83	$ 2,572.28								
45	HB Threshold															
46																
47	**Summer:**															
48	Cust. Chg								$ 167.06	$ 167.06	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,010.48	$ 2,012.84
49	Headblock								$ 166.08	$ 166.08	$ 119.59	$ 103.61	$ 112.86	$ 143.03	$ 811.24	$ 3,231.89
50	Tailblock								$ 254.20	$ 23.26	$ -	$ -	$ -	$ -	$ 277.46	$ 2,849.74
51	HB Threshold															
52																
53	Total Base Rate Amount	$ 511.70	$ 911.04	$ 1,331.16	$ 1,247.70	$ 1,025.60	$ 968.09	$ 5,995.28	$ 587.34	$ 356.40	$ 288.68	$ 272.70	$ 281.95	$ 312.12	$ 2,099.18	$ 8,094.46
54																
55	COG Rate - (Seasonal)	$ 0.7403	$ 0.7403	$ 0.7496	$ 0.6707	$ 0.5204	$ 0.5817	$ 0.6640	$ 0.4417	$ 0.4417	$ 0.5517	$ 0.5517	$ 0.5517	$ 0.5517	$ 0.4843	$ 0.6347
56	COG amount	$ 614.49	$ 1,620.25	$ 2,779.15	$ 2,284.26	$ 1,354.50	$ 1,393.11	$ 10,045.76	$ 582.61	$ 213.82	$ 157.01	$ 136.04	$ 148.17	$ 187.79	$ 1,425.44	$ 11,471.21
57																
58	LDAC	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
59	LDAC amount	$ 62.84	$ 165.68	$ 280.66	$ 257.82	$ 197.03	$ 181.29	$ 1,145.32	$ 99.85	$ 36.65	$ 21.54	$ 18.67	$ 20.33	$ 25.77	$ 222.80	$ 1,368.12
60																
61	**Total Bill**	**$ 1,189.03**	**$ 2,696.97**	**$ 4,390.97**	**$ 3,789.78**	**$ 2,577.13**	**$ 2,542.49**	**$ 17,186.36**	**$ 1,269.79**	**$ 606.87**	**$ 467.23**	**$ 427.41**	**$ 450.45**	**$ 525.68**	**$ 3,747.43**	**$ 20,933.79**
62																
63	**DIFFERENCE:**															
64	**Total Bill**	**$ (117.64)**	**$ (315.41)**	**$ (571.29)**	**$ (255.79)**	**$ 196.58**	**$ 34.36**	**$ (1,029.19)**	**$ (22.09)**	**$ (6.42)**	**$ (37.61)**	**$ (32.59)**	**$ (35.50)**	**$ (44.99)**	**$ (179.19)**	**$ (1,208.39)**
65	% Change	**-9.89%**	**-11.69%**	**-13.01%**	**-6.75%**	**7.63%**	**1.35%**	**-5.99%**	**-1.74%**	**-1.06%**	**-8.05%**	**-7.63%**	**-7.88%**	**-8.56%**	**-4.78%**	**-5.77%**
66																
67	**Base Rate**	$ 6.18	$ 11.07	$ 16.24	$ 15.21	$ 12.48	$ 11.77	$ 72.95	$ 7.15	$ 4.32	$ -	$ -	$ -	$ -	$ 11.47	$ 84.42
68	% Change	1.21%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.21%	0.00%	0.00%	0.00%	0.00%	0.55%	1.04%
69																
70	**COG & LDAC**	$ (123.82)	$ (326.48)	$ (587.53)	$ (271.00)	$ 184.10	$ 22.58	$ (1,102.14)	$ (29.24)	$ (10.73)	$ (37.61)	$ (32.59)	$ (35.50)	$ (44.99)	$ (190.67)	$ (1,292.81)
71	% Change	-18.28%	-18.28%	-19.20%	-10.66%	11.87%	1.43%	-9.85%	-4.28%	-4.28%	-21.07%	-21.07%	-21.07%	-21.07%	-11.57%	-10.07%
	check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2020 Summer Cost of Gas Filing
Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-52

November 1, 2019 - April 30, 2020
Commercial Rate (G-52)

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Winter Nov-Apr
Typical Usage (Therms)		1,352	1,866	2,284	2,160	1,886	1,760	11,306
Winter:	7/1/2019							
Cust. Chg	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,014.54
Headblock	$ 0.2392	$ 239.20	$ 239.20	$ 239.20	$ 239.20	$ 239.20	$ 239.20	$ 1,435.20
Tailblock	$ 0.1593	$ 56.03	$ 137.94	$ 204.48	$ 184.73	$ 141.07	$ 121.08	$ 845.32
HB Threshold	1,000							
Summer:								
Cust. Chg	$ 169.09							
Headblock	$ 0.1733							
Tailblock	$ 0.0985							
HB Threshold	1,000							
Total Base Rate Amount		$ 464.32	$ 546.23	$ 612.77	$ 593.02	$ 549.36	$ 529.37	$ 3,295.06
COG Rate - (Seasonal)		$ 0.6258	$ 0.6258	$ 0.6258	$ 0.6258	$ 0.6258	$ 0.6258	$ 0.6258
COG amount		$ 845.92	$ 1,167.69	$ 1,429.07	$ 1,351.49	$ 1,179.97	$ 1,101.44	$ 7,075.59
LDAC		$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
LDAC amount		$ 64.65	$ 89.25	$ 109.22	$ 103.30	$ 90.19	$ 84.18	$ 540.79
Total Bill		**$ 1,374.90**	**$ 1,803.17**	**$ 2,151.06**	**$ 2,047.81**	**$ 1,819.51**	**$ 1,715.00**	**$ 10,911.44**

May 1, 2020 - October 31, 2020

	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
Cust. Chg	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,014.54	$ 2,029.08
Headblock	$ 173.30	$ 173.30	$ 173.30	$ 173.30	$ 173.30	$ 155.41	$ 1,021.91	$ 2,457.11
Tailblock	$ 48.96	$ 12.58	$ 3.15	$ 2.47	$ 4.90	$ -	$ 72.06	$ 917.38
Total Base Rate Amount	$ 391.35	$ 354.97	$ 345.54	$ 344.86	$ 347.29	$ 324.50	$ 2,108.51	$ 5,403.57
COG Rate - (Seasonal)	$ 0.4591	$ 0.4591	$ 0.4591	$ 0.4591	$ 0.4591	$ 0.4591	$ 0.4591	$ 0.5642
COG amount	$ 687.28	$ 517.74	$ 473.77	$ 470.60	$ 481.96	$ 411.71	$ 3,043.06	$ 10,118.66
LDAC	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478	$ 0.0478
LDAC amount	$ 71.60	$ 53.94	$ 49.36	$ 49.03	$ 50.21	$ 42.89	$ 317.03	$ 857.83
Total Bill	**$ 1,150.22**	**$ 926.66**	**$ 868.66**	**$ 864.48**	**$ 879.47**	**$ 779.11**	**$ 5,468.61**	**$ 16,380.05**

November 1, 2018 - April 30, 2019
Commercial Rate (G-52)

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr
Typical Usage (Therms)	1,352	1,866	2,284	2,160	1,886	1,760	11,306
Winter:							
Cust. Chg	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 167.06	$ 1,002.36
Headblock	$ 236.30	$ 236.30	$ 236.30	$ 236.30	$ 236.30	$ 236.30	$ 1,417.80
Tailblock	$ 55.36	$ 136.29	$ 202.04	$ 182.52	$ 139.38	$ 119.63	$ 835.24
HB Threshold							
Summer:							
Cust. Chg							
Headblock							
Tailblock							
HB Threshold							
Total Base Rate Amount	$ 458.72	$ 539.65	$ 605.40	$ 585.88	$ 542.74	$ 522.99	$ 3,255.40
COG Rate - (Seasonal)	$ 0.7456	$ 0.7456	$ 0.7549	$ 0.6760	$ 0.5257	$ 0.5870	$ 0.6728
COG amount	$ 1,007.86	$ 1,391.23	$ 1,723.88	$ 1,459.91	$ 991.23	$ 1,033.15	$ 7,607.26
LDAC	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
LDAC amount	$ 102.33	$ 141.25	$ 172.87	$ 163.48	$ 142.74	$ 133.24	$ 855.90
Total Bill	**$ 1,568.91**	**$ 2,072.13**	**$ 2,502.15**	**$ 2,209.27**	**$ 1,676.71**	**$ 1,689.38**	**$ 11,718.56**

May 1, 2019 - October 31, 2019

	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
Cust. Chg	$ 167.06	$ 167.06	$ 169.09	$ 169.09	$ 169.09	$ 169.09	$ 1,010.48	$ 2,012.84
Headblock	$ 171.20	$ 171.20	$ 173.30	$ 173.30	$ 173.30	$ 155.41	$ 1,017.71	$ 2,435.51
Tailblock	$ 48.96	$ 12.58	$ 3.15	$ 2.47	$ 4.90	$ -	$ 72.06	$ 907.30
Total Base Rate Amount	$ 387.22	$ 350.84	$ 345.54	$ 344.86	$ 347.29	$ 324.50	$ 2,100.25	$ 5,355.65
COG Rate - (Seasonal)	$ 0.4506	$ 0.4506	$ 0.5633	$ 0.5633	$ 0.5633	$ 0.5633	$ 0.5187	$ 0.6159
COG amount	$ 674.55	$ 508.16	$ 581.30	$ 577.41	$ 591.35	$ 505.16	$ 3,437.93	$ 11,045.19
LDAC	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757	$ 0.0757
LDAC amount	$ 113.32	$ 85.37	$ 78.12	$ 77.60	$ 79.47	$ 67.89	$ 501.76	$ 1,357.66
Total Bill	**$ 1,175.09**	**$ 944.37**	**$ 1,004.95**	**$ 999.86**	**$ 1,018.11**	**$ 897.55**	**$ 6,039.94**	**$ 17,758.50**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
Total Bill	**$ (194.01)**	**$ (268.96)**	**$ (351.09)**	**$ (161.47)**	**$ 142.81**	**$ 25.61**	**$ (807.11)**
% Change	**-12.37%**	**-12.98%**	**-14.03%**	**-7.31%**	**8.52%**	**1.52%**	**-6.89%**
Base Rate	$ 5.60	$ 6.58	$ 7.37	$ 7.13	$ 6.61	$ 6.37	$ 39.66
% Change	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
COG & LDAC	$ (199.61)	$ (275.54)	$ (358.45)	$ (168.60)	$ 136.19	$ 19.24	$ (846.78)
% Change	-17.98%	-17.98%	-18.90%	-10.39%	12.01%	1.65%	-10.01%
check	$ -	$ -	$ -	$ 0.00	$ -	$ (0.00)	$ (0.00)

	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$ (24.87)**	**$ (17.71)**	**$ (136.29)**	**$ (135.38)**	**$ (138.65)**	**$ (118.44)**	**$ (571.33)**	**$ (1,378.45)**
% Change	**-2.12%**	**-1.88%**	**-13.56%**	**-13.54%**	**-13.62%**	**-13.20%**	**-9.46%**	**-7.76%**
Base Rate	$ 4.13	$ 4.13	$ -	$ -	$ -	$ -	$ 8.26	$ 47.92
% Change	1.07%	1.18%	0.00%	0.00%	0.00%	0.00%	0.39%	0.89%
COG & LDAC	$ (29.00)	$ (21.84)	$ (136.29)	$ (135.38)	$ (138.65)	$ (118.44)	$ (579.59)	$ (1,426.37)
% Change	-3.68%	-3.68%	-20.67%	-20.67%	-20.67%	-20.67%	-14.71%	-11.50%
check	$ (0.00)	$ (0.00)	$ -	$ -	$ -	$ -	$ -	$ (0.00)

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2020 Summer Cost of Gas Filing

Residential Heating

	Summer 2019	Summer 2020
Customer Charge	$ 15.20	$ 15.20
First 20 Therms	$ 0.5569	$ 0.5569
Excess 20 Therms	$ 0.5569	$ 0.5569
LDAC	$ 0.0945	$ 0.0310
COG	$ 0.4943	$ 0.4520
Total Adjust	$ 0.5888	$ 0.4830

		Summer 2019 COG @	Summer 2020 Cog @	Total $ Impact	Total % Impact	Base Rate $ Impact	Base Rate % Impact	COG $ Impact	COG % Impact	LDAC $ Impact	LDAC % Impact
		$ 0.5888	$ 0.4830	$ (0.11)	-18%						
Cooking alone	5	$ 2.94	$ 20.40	$ 17.46	593%	$ 17.98	611%	$ (0.21)	-1%	$ (0.32)	-11%
	10	$ 5.89	$ 25.60	$ 19.71	335%	$ 20.77	353%	$ (0.42)	-2%	$ (0.64)	-11%
	20	$ 11.78	$ 36.00	$ 24.22	206%	$ 26.34	224%	$ (0.85)	-2%	$ (1.27)	-11%
Water Heating alone	30	$ 17.66	$ 46.40	$ 28.73	163%	$ 31.91	181%	$ (1.27)	-3%	$ (1.91)	-11%
	45	$ 26.49	$ 61.99	$ 35.50	134%	$ 40.26	152%	$ (1.90)	-3%	$ (2.86)	-11%
	50	$ 29.44	$ 67.19	$ 37.76	128%	$ 43.05	146%	$ (2.11)	-3%	$ (3.18)	-11%
Heating Alone	80	$ 44.16	$ 93.19	$ 49.03	111%	$ 56.97	129%	$ (3.17)	-3%	$ (4.76)	-11%
	125	$ 78.31	$ 153.50	$ 75.20	96%	$ 89.27	114%	$ (5.62)	-4%	$ (8.45)	-11%
	150	$ 88.31	$ 171.18	$ 82.87	94%	$ 98.74	112%	$ (6.34)	-4%	$ (9.53)	-11%
	200	$ 117.75	$ 223.17	$ 105.42	90%	$ 126.58	107%	$ (8.45)	-4%	$ (12.71)	-11%

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 19-145

<u>In the Matter of:</u>

Liberty Utilities (Energynorth Natural Gas) Corp.
Winter 2019/2020 And Summer 2020 Cost Of Gas Filing

Direct Testimony

of

Al-Azad Iqbal
Utility Analyst – Gas & Water Division

October 08, 2019

Q. Please state your name, current position, and business address.

A. My name is Al-Azad Iqbal. I am employed by the New Hampshire Public Utilities Commission (Commission) as a Utility Analyst. I have been a Utility Analyst from 2007 to the present. My business address is 21 South Fruit Street, Suite 10, Concord, New Hampshire, 03301.

Q. Please summarize your educational and professional background.

A. My educational and professional background is summarized in Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Commission Staff's analysis of the Liberty Utilities (Energynorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty EnergyNorth, or the Company) Winter 2019/2020 and Summer 2020 Cost Of Gas Filing wherein the company filed Revenue Decoupling Adjustment (RDA) calculations for the first time since decoupling went into effect on November 1, 2018.[1] In this testimony, Commission Staff (Staff) explains Staff's analysis of the RDA related tariff issue the Company raised in its initial filing, Staff's proposed corrections to the Company's Schedule 19 RDAF (Bates page 118-129), Local Delivery Adjustment Clause (LDAC) (Tariff page 97), and Staff recommendation regarding the normal weatherization adjustment (NWA) as applied to the proposed cost of gas (COG) rates for Liberty EnergyNorth customers. Liberty agreed with Staff and, on October 7, 2019, filed revised testimony and schedule pages.

[1] *See* Order No. 26,122 at 43-46, 53-55 (April 27, 2018) (approving decoupling); Order No. 26, 187 at 11 (November 2, 2018 (addressing Liberty's motion for rehearing).

Q. Please summarize the issues addressed in this testimony.

A. While reviewing Liberty's initial Filing, Staff identified the following issues with regard to Liberty's RDAF calculations:

- The Company initially claimed that the tariff related to RDAF calculation (Tariff page 34-38) does not match the intent of the RDAF because Liberty believed that the calculations of actual revenue and allowed revenue for R-4 customers were not aligned with each other. Staff disagreed and explained the reasons to the company in a technical session.
- The Company used the wrong Benchmark Base Revenue per bill (Schedule 19, page 8) for the period of November 2018 to June 2019.
- Staff discovered that the tariff language/formula to calculate RDAF does not incorporate an NWA monthly adjustment.

The Company ultimately agreed with Staff, and made a revised filing on October 7, 2019, that proposed to adjust schedules and testimony to correct the above errors.

Q. Please explain the issue related to R-4 revenue.

A. R-4 is a rate class for low-income heating customers**.** Low-income customers pay a 60% discounted delivery rate and 60% discounted customer charges as compared to R-3 heating customers. R-3 is a rate class for regular residential hearing customers. The cost of the discount for R-4 is collected and paid to the Company through the Residential Low Income Assistance Program (RLIAP) charge. All rate class customers, including R-4 customers, pay an LDAC charge, which includes the RLIAP charge. In combination, money from the R-4 (low income) customer class charges plus the RLIAP charge is equivalent to what would have been collected from R-4 customers if they had been charged the R-3 (regular residential hearing class) rates. Since the Company is already made whole for the discount offered to low-income (R-4) customers after revenue collected from the RLIAP charge is collected, Liberty's initial "adjustment" for R-4 customers overestimated compensation due to the Company by approximately 2.1 million dollars. Staff's analysis is consistent with the relevant tariff language which states that "For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R4, shall be determined based on non-discounted rate R-3" when calculating the AR_{T-1} (Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year. See Tariff page 37). The intent of RDAF and tariff language match perfectly in this context.

Q. Please explain the second issue related to Benchmark Base Revenue per bill.

A. In its initial filing, the Company incorrectly used the latest rates, which were effective from July 1, 2019, for the whole decoupling period of Benchmark Base Revenue per bill calculation. The Benchmark Base Revenue per bill ($BRPC_{T-1)}$ is used to calculate the allowed revenue for the decoupling year. As the rates increased on July 1, 2019, the application of these rates for the entire decoupling year incorrectly inflated the allowed revenue by approximately 0.8 million dollars. The Company made a revised filing on October 7, 2019, that proposed changes to correct this error.

Q. Please explain the third issue related to the monthly NWA.

A. During the review of the RDAF calculations, Staff discovered that the tariff is ambiguous with regard to how to incorporate the real-time normal weather adjustment in the calculation of actual revenue in the context of the RDAF formula. According to the Tariff (page 34, Section D.4 (a): "The Company will use monthly distribution revenues and Actual Number of Customers to determine the Monthly Actual Base Revenue per Customer." This description underlies the tariff's Revenue Decoupling Adjustment Formulas (RDAF) on Tariff page 36 section 17.D.5 (b). This formula does not incorporate the real-time normal weather adjustment (NWA) which changes the actual revenue the company collects from customers. Without modification, the actual revenue calculated in the RDAF would either be higher or lower than actual revenue depending on the monthly normal weather adjustment (NWA) charge or credit. The annual reconciliation would not address this issue either, as it is not part of the RDAF calculation. In its analysis, Staff identified this issue. It is anticipated that Liberty will file proposed corrections to the tariff language to incorporate the NWA, and correct for NWA variations.

Q. Did the revised filing address this NWA issue?

A. Yes. The current tariff (page 36) defines the Normal Weather Factor (NWF) in terms of "delivery charges normal" and delivery charges actual." In its revised schedules, the Company proposed calculating NWF using normalized sales (normalizing Dth sales) to determine the actual revenue for RDAF purposes. Staff believes that using normalized sales in Dth to calculate the revenue effectively incorporates the NWA.

Q: Is current tariff language sufficient?

A: No. Staff believes the tariff should be amended to explicitly account for the NWA.

Q. Do you have any more comments?

A. Yes. Staff's review of the Company's RDAF calculations was limited to the data provided by the Company. Staff did not check the veracity of the inputs in the models used in the filing. Staff reserves the right to identify other issues or concerns with the Company's filing.

Q. Does that conclude your testimony?

A. Yes.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of

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

Docket No. DG 20-105

Petition for Permanent Rate Increase

DIRECT TESTIMONY

OF

Al-Azad Iqbal
Economics/Finance Director

Office of the Consumer Advocate

March 18, 2021

Contents

Introduction

Q. Please state your name, occupation, and business address.

A. My name is Al-Azad Iqbal, and I am employed by the New Hampshire Office of the Consumer Advocate as Economics/Finance Director. My business address is 21 South Fruit Street, Suite 18, Concord, New Hampshire, 03301.

Q. Please summarize your educational and professional experience.

A. My educational and professional backgrounds are summarized in Appendix A.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide recommendations on issues related to the Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty, or the Company) rate proposal regarding 1) depreciation; 2) rate design, rate plan and; 3) other rate-related issues.

Q. Please summarize your recommendations on these issues.

A. I recommend that the depreciation reserve variance amortization, approved in the last rate case, be ceased until a new depreciation study is completed. The Company should follow the recommendations in the Review of Reserve Variance Deficiency for Liberty Depreciable Gas Plant done by Paul Normand and Marcy Stefan of Management Applications Consulting, Inc. (MAC); which is found at Testimony of Steven E. Mullen, Attachment SEM (Bates II 235-239) in Liberty's initial filing of July 31, 2020, in this docket. I recommend certain updates in the rate design process concerning the treatment of decoupling and low-income discounts. I also raise concerns about the Company's proposed capital budget, and the rate plan with step adjustments.

Depreciation

Q. What is the significance of depreciation for purposes of this proceeding?

A. As with all public utilities, EnergyNorth includes in its annual revenue requirement an amount that is, at least theoretically, equal to the decline in the value of the company's capital assets over a 12-month period. This is necessary because all capital assets decline in value over their period of usage. To account for that, the annual amount of depreciation is deducted from the utility's rate base (on which the utility receives a return on investment) and that same value becomes a recoverable operating cost. In this manner, the utility's shareholders receive both a return *on* their investment and, via depreciation charges, a return *of* their investment.

The accounting necessary to determine the amount recoverable from ratepayers as a depreciation expense is complicated. Utilities, including EnergyNorth, must constantly add new capital assets to their rate base. Meantime, operating conditions are not static and thus existing assets do not depreciate precisely as they were expected to at the time they first go into rate base. For this reason, a utility like EnergyNorth commissions a depreciation study from time to time, usually conducted by consultants who are expert in the field of depreciation. A depreciation study is a statistical exercise that takes into account the vintage of the utility's assets – that is, the year when each asset was placed into service – the pace at which specific assets are being retired from service, and actuarial principles that are helpful in updating determinations of how much useful life remains in the rate-based assets. The depreciation experts use statistical techniques to make mathematical calculations of how the forces of retirement are acting upon each plant category and an estimate of the service life remaining in each such category.

Q. When was the last depreciation study done for EnergyNorth?

A. EnergyNorth's last depreciation study was done in Docket DG 17-048, the company's most recent rate case before this one. In that docket, the company's depreciation consultant -- Management Applications Consulting (MAC) -- used a Simulated Plant Record (SPR) life analysis approach. The SPR approach is useful when a utility lacks sufficient records to develop actuarial data. In connection with this current docket, EnergyNorth again engaged Mr. Normand's firm. MAC did not conduct a complete depreciation study as it did for the previous rate case but, rather, reviewed the growth in the Company's plant with the goal of quantifying changes in the depreciation reserve imbalance (as required by the order issued in Docket DG 17-048 on April 27, 2018 (Order No. 26,122). The findings of Mr. Normand (along with his colleague, Marcy Stefan) are attached to Mr. Mullen's testimony as Attachment SEM 3.

Q. What is a "depreciation reserve imbalance"?

A. A utility's depreciation reserve is a fund the company accumulates annually, based on the probable replacement cost of its depreciable assets. The depreciation reserve – also referred to as accumulated depreciation – is equal to the total amount of depreciation charged against all of the utility's capital assets as stated on the utility's balance sheet. A depreciation reserve imbalance occurs when there is a difference between the depreciation reserve on the company's balance sheet (booked reserve) and the calculated value of the accumulated depreciation (theoretical reserve). When a comparatively large depreciation reserve imbalance exists, it is necessary to determine how to correct it. The imbalance can be amortized over a relatively short period of time or it can be spread over the entire future remaining life of the plant in service.

Q. Please describe the findings of Mr. Normand's and Ms. Stefan's review (as contained in Attachment SEM – 3).

A. The depreciation consultants stated that even with the amortization of the reserve variance approved in the prior rate case, the reserve variance increased significantly. The biggest contributors to this increase are Mains (accounts 367 and 376), and Services (account 380), which were the same accounts that caused the reserve variance in the depreciation study done in Docket 17-048. In the report found at Attachment SEM-3, MAC identified three items affecting the reserve variance that should be examined in the context of a new depreciation study: 1) potential change in average service life (ASL); 2) replacement/retirement of large quantities of mains and services; and 3) the cost of removal portion of the Company's plant replacement activities.

MAC posited that a new study would derive longer ASLs for both mains and services which would impact the resulting reserve variance. Further, MAC stated: "… large growth in plant investments which has been occurring for many years, especially for key plant accounts related to mains and services, results in large amounts of unrecovered dollars being identified but not recovered in the short term".[1] MAC further stated: "In the last ten years, the rapid increase in plant replacement/retirement requirements had, in many cases, resulted in a more detailed review of these costs (COR) which has resulted in being modified to reflect a much lower 3 to 5% range of costs to new plant investments."[2]

Based on its review, MAC recommended that Liberty do a detailed review of COR and undertake a new depreciation study. As I explain more fully later, COR is an important aspect of depreciation because, obviously, when the useful life of an asset has been fully exhausted it must be physically removed, which has a cost that is properly included in the calculation of depreciation costs.

Q. Is the recommendation for a detailed review of COR through a new depreciation study consistent with the goal of the depreciation study?

A. Yes. In the last depreciation study, MAC discussed the relevant issues in the context of the whole life depreciation system (*see* Docket No. DG 17-048, Attachment PMN-2, Bates page 431):

> The whole life accrual rate is a function of two variables: the estimated net salvage (salvage less cost to retire) and the average service life of the group. The continued use of accrual rates properly developed at one point in time as a function of all circumstances known and projected at that time can be assumed to be appropriate for a limited number of years; however, if the lives and net salvage are not re-estimated periodically, the rates may not provide the

1 *See* Attachment SEM-3, Bates page II-236.

2 *Id*.

> appropriate recovery of capital.

He also stated:

> Obviously, when a change in either net salvage or life expectations is observed, the book depreciation reserve compared to the computed or theoretical reserve immediately appears as either over or under accrued.
>
> …..
>
> In general, the variance in the reserve is simply the difference between theoretical reserve based on an updated set of factors as developed in a depreciation study and the existing book reserves which reflect the historical reserve adjustments previously approved. The theoretical reserve calculation, however, is based on a new set of accrual rates, and applying these results to the current plant balances as if they were constant historical factors will result in a variance.

He also explained:

> …statistical mortality studies of past retirement experience may provide historical indications of the dispersion of retirements and of average service life if there has been sufficient retirement activity over a reasonable period of time. Such information may provide some indication as to what to expect in the future; however, it should not be taken for granted that the future will mirror the past, especially when present policies, plans, or external circumstances indicate otherwise.

So Mr. Normand's recommendation is consistent with his overall approach to the depreciation study. The quotes I just provided also highlight the need to update the sets of factors as the data clearly indicates the current ASL, and CORs are not representing the characteristics of the company's assets.

Q. What is your opinion about the Average Service Life issue?

A. I agree with the consultant's analysis. Between 2007 and 2016, according to the two depreciation studies, Liberty's plant balance for Gas Mains increased by 70%, and for Gas Services by 74%. Further, since the last depreciation study in Docket DG 17-048, which was based on 2016 balances, these account plant balances have increased by 35% and 28%,[3] respectively in the test year. Effectively, the characteristics of these assets have changed significantly in recent years. Given these balances have essentially doubled in the past 15 years or so, and given that the more recent plant additions are supported by more reliable accounting data that is available for study, we concur with the consultants' recommendation that a new deprecation study based on 2020 data be performed in early 2021 to evaluate the impact on ASLs.[4]

Q. Please elaborate on the Cost of Removal issue.

A. On this issue, I agree with Mr. Normand's and Ms. Stefan's analysis in Attachment SEM 3. The current practice of applying a flat 10% (of plant investment) estimate for the cost of removal might not be reflecting the actual COR. MAC pointed out that in the last decade, more detailed reviews of COR have resulted in a much lower range (3% to 5%) for COR related to new plant investments. The COR is primarily labor costs. With industry improvements in automation, asset management technology, etc., the COR should be reduced over time. For example, GIS-based geocoding of the mains would make it possible to pinpoint the precise

[3] *See* Attachment SEM-3, Bates page II-235.

[4] In the last study, MAC identified data problem for both Mains, and Services accounts and stated: "Our analyses of this account were based on total assets since the Company could not provide any historical details by material type for analyses. … we note that the recording of retirements for the last two years has been backlogged." *See* Docket DG 17-048, Attachment PMN-2, at 35 and 37 (Bates pages 445 and 447).

location of an asset, which would reduce the need for unnecessary digging and corresponding labor costs. The century-old mains and services the Company is replacing now had very little documentation compared to today's accounting and documentation standards. As a result, the COR of new assets is expected to be more efficient, and applying the same blanket percentage (10%) to current investment costs would not be representative of those lower, future costs (when today's investments need to be removed).automation, asset management technology, etc., the COR should be reduced over time. For example, GIS-based geocoding of the mains would make it possible to pinpoint the precise location of an asset, which would reduce the need for unnecessary digging and corresponding labor costs. The century-old mains and services the Company is replacing now had very little documentation compared to today's accounting and documentation standards. As a result, the COR of new assets is expected to be more efficient, and applying the same blanket percentage (10%) to current investment costs would not be representative of those lower, future costs (when today's investments need to be removed).

Q. Please explain how the Cost of Removal impacts depreciation expenses.

A. The cost of removal is a component of the net salvage value. The net salvage component is an important factor in determining the annual accrual rate for each account. A COR represents the cost of disposing of an asset at the end of its life. For regulatory purposes, this cost is typically incorporated as a component of book depreciation. So a higher COR would require higher accrual rates and thus requires higher depreciation expenses.

Q. Please explain how the Cost of Removal impacts the reserve variance.

A. As previously mentioned, the reserve variance is the difference between theoretical reserves and existing book reserves. The theoretical reserve is based on an updated set of factors including COR. A change in COR would have a significant impact on the theoretical reserve, and thus on the variance. For example, if COR were reduced from 10% to 5% of the new investments as indicated in the review, it would reduce Net Salvage by approximately half.[5] If we adjust Net Salvage by half, the combined reserve variance from Mains and Services would change from a $16.3 million shortfall to a $4.5 million surplus. The same would have been true for the depreciation study from DG 17-048, and would have resulted in a surplus of $5.7 million rather than the shortfall of $9.9 million which is currently being amortized. When a reserve variance shortfall is amortized, the revenue requirement increases to the detriment of the ratepayers. When a reserve variance surplus is amortized, the revenue requirement decreases to the benefit of ratepayers.

Q. What is your recommendation?

A. It is obvious that the current set of factors (ASL and COR) need to be updated which will change the reserve variance significantly. So the amortization of the reserve variance which increases the revenue requirement by approximately $1.5 million is unnecessary and unreasonable. I support MAC's recommendations regarding a new depreciation study and

[5] For example, Mains net salvage would reduce to 7.5% from 15%.

recommend that the reserve amortization approved in the last rate case be discontinued in this case and any further amortization should be authorized only after the detailed COR and ASL evaluations MAC recommended are conducted, and/or a new depreciation study is completed. If this docket is completed before those studies are available, I recommend that the amortization be discontinued.

Q. Please explain the rationale of your recommendation.

A. As indicated by MAC, ASL and COR were the main factors cited in the last depreciation study as contributing to the reserve variance. Likewise, the current recommendation is to review the Mains and Services accounts. If ASL is increased and COR is reduced (as MAC's report at Attachment SEM-3, p. 2 suggest may be warranted), the reserve variance will be significantly reduced.

In the depreciation study in DG 17-048, Mr. Normand pointed out that the large swing in the reserve variance (from the prior study, which showed a reserve surplus) was the direct result of the very large, recent increases in investments in mains and services. The expectation in DG 17-048 was that this level of investments would continue to be exhibited in a similar fashion as has been experienced in the past.[6] In DG 17-048, Mr. Normand mentioned, establishing a "collar" or a threshold bandwidth for the variance, such that no amortization would occur unless

[6] *See* Attachment AMI-4; response to Staff 7-9(a) in DG 17-048: "The large deviation is a direct result of the very large plant dollar increases for these accounts (Mains $98M, Services $66M) driven primarily by the mandated replacement program (CIBS) which is expected to continue for some period of time. As a result, we expect that this behavior will continue to be exhibited in a similar fashion as has been experienced but at a lower level since the recent amortization from the last study will be terminated."

the variance was in excess of 5% -10% of the theoretical reserve level, as an option to minimize the swing.[7] The current reserve variance is below a 10% threshold, so no amortization would be done under that approach. In the last study, in Docket DG 17-048, the reserve balance was just above 6%. As indicated earlier, if ASL and COR are adjusted as a result of the reviews recommended in Attachment SEM-3, the variance would be lower and could be eliminated (i.e., in surplus).

In DG 17-048, the Commission approved a variance amortization at an accelerated rate of 6 years instead of 12 years approved in the case prior to DG 17-048. In addition, the Commission required that Liberty re-examine the reserve balance in its next case, as Mr. Normand and Ms. Stefan have done with the report submitted as Attachment SEM-3. Continuing to amortize the reserve variance at an accelerated rate as proposed by Liberty in this case without waiting for the results of the analyses recommended by the consultants in their report (Attachment SEM-3) is unreasonable, especially given Mr. Normand's and Ms. Stefan's suggestion that two specific areas (ASL and COR) are ripe for review and adjustment, and especially when a correction to these items could produce a variance that is much smaller (below 5%), and could potentially lead to a significant reduction in rates.

[7] *See* Attachment AMI-4; response to Staff 7-9(c)(2) in DG 17-048. "If maintaining the WL [whole life] approach is required, then consider establishing a collar or a threshold band width for the variance such that no amortization would occur unless the variance is in excess of 5 or 10% of the theoretical level."

Rate Plan

Q. Please review some of the factors identified by the Company that led to the rate case filing in the current docket?

A. Mr. Mullen stated at Bates Page II-198 of his testimony that the major factor driving the Company's current rate request is the lag in recovery of capital investments and increases in costs, such as property taxes. He also mentioned the following factors - 1) decoupling; 2) reclassification of C&I customers; and 3) year-end customer count adjustment.

Q. Please address the decoupling issue cited by the Company.

A. The Company states that an increase in use (of gas) per customer (usage per customer, or UPC) impacts the Company negatively, but provides no support for this conclusion. Conceptually, UPC should have no impact on revenue under the approved decoupling mechanism. Decoupling sets the revenue per customer (RPC) based on test year data, not actual data. If the UPC changes from year to year, RPC should not. An increase in UPC might increase a customer's bill but would not impact the Company's revenue allowed under decoupling because any variances between allowed and actual revenue due to changes in UPC would be captured as over-or-under collections and would be reconciled through the Local Distribution Adjustment Clause (LDAC) Revenue Decoupling Adjustment Factor (RDAF) mechanism.

The concept of decoupling is based on the assumption that energy efficiency policies and programs reduce the sales of a utility's commodity – in this case, gas sales – and thus negatively affect the Company's earnings. Decoupling is designed to break this link between sales and revenues to eliminate any disincentive for utilities to implement EE programs based on the expectation that reductions in UPC result in associated reductions in revenue.

The reverse is also true – when UPC goes up, the revenue is not affected under decoupling. The Company's own review by its consultant (*see* Attachment AMI-1, OCA TS 1-7.3, Company Response to OCA DR TS 1-7) indicates that UPC does not impact the Company's revenue. Thus, I strongly disagree with the Company that decoupling warranted, or justifies, - the current rate case.

Q. Please address the rate class reclassification issue.

A. The Company claims that the reclassification of 1,598 commercial and industrial customers after the test year negatively impacted its revenue. The reclassification was the result of the Company's post-test year Rate Review process (Attachment AMI-2, Company Response to Staff DR 3-5.b). It is common practice for utilities to adjust customer rate classifications within a rate review process.

Q. What is your opinion on how the rate reclassification impacted the Company?

A. A rate classification adjustment could impact revenue, depending on the scale of migration from one class to another, because reclassification will determine the allowed revenue for those customers under decoupling. Usually, such migration patterns do not fluctuate significantly and impacts are negligible. If a customer migrates from a lower RPC class to a higher RPC class, the Company's allowed revenue would increase by the difference between the two RPCs and *vice versa*. According to the Company's analysis, the impact of reclassification is a reduction in allowed revenue under decoupling of $0.9 million. (Attachment AMI-2, Company Response to Staff DR 3-5.b).

The Company did not elaborate on the key reasons that could explain the somewhat large impact due to customer migration between rate classes. It matters how frequently the company reclassifies its customers. If the Company reclassifies its customers in a timely and diligent manner the impact due to reclassification cannot be substantive. The accuracy of the Company's test year revenues is important in any rate case filing. In this case, the Company claims a negative impact to its revenues, but in another situation the same factors might have a positive impact on its revenues.

Q. Please explain the end of the year adjustment issue?

A. Mr. Mullen described the end of year (EOY) adjustment issue as a methodology issue (Bates 11-199):

> The revenue adjustment was performed in a simplified manner, but the results of that adjustment were found to vary significantly from the determination of revenues to be received from customers under the Company's decoupling structure that uses monthly RPC amounts that vary by class. Due to the significant variations in monthly RPC amounts, the simplified methodology in the year-end customer count adjustment overstated the amount of revenue to be received from new customers.

I believe Liberty is concerned about the EOY adjustment methodology, which was proposed by Staff in DG 17-048 and was ultimately approved by the Commission. I believe that the simple methodology which was used in the last rate case (and in many other electric and gas rate cases and approved by the Commission) is reasonable. Usually, an EOY adjustment increases revenue and is applied to the test year sales number without any adjustment. In the rehearing process in DG 17-048, Staff identified the need for sales to be adjusted to ensure accurate rates. So while it is true that the application of the EOY adjustment to test year sales increase those sales for rate-setting purposes (which is consistent with using a year-end rate base in rate-setting) the same adjustment caused inflated rates in previous instances. This issue should be properly investigated where it is still used. In the current rate case, the EOY adjustment has been refined to address the data accuracy to a certain level. There might still be some room for improvement. OCA is open to improvements in the methodology, but supports the EOY adjustments as known and measurable adjustments that are consistent with using the year end rate base.

Rate Plan/Step Adjustments

Q. Why is the Company proposing multi-year step adjustments?

A. Mr. Mullen stated at Bates II-209 that "the largest negative impact on a utility's earnings between rate cases is the regulatory lag between the time capital investments are made and the time that recovery of the revenue requirement associated with those capital investments begins, particularly when those investments are considered non-revenue producing or non-growth related." He also pointed to the termination of the CIBS program and the need for an alternative method to obtain timely recovery of the costs involved with replacing leak-prone pipe on its distribution system.

Q. What is your opinion regarding non-revenue producing or non-growth related investment as a reason for multiple step adjustments?

A. Theoretically, investments that are not revenue producing or growth-related could be the basis for multiple step adjustments, but in this instance the planning and policy practices of Liberty undermine reliance on such investments as a reason for automatic rate increases outside of a rate case (when such planning and policy practices can be fully reviewed). Every utility faces regulatory lag. Customer growth provides an opportunity to minimize the impact of the regulatory lags, because customer growth produces increased revenue. Under decoupling, the revenue is stabilized for the Company but allowed to increase with customer growth. A reasonable utility would look for a balance between growth and non-growth capital investment so that the impact of regulatory lag would be manageable. Liberty's capital budget for the next five years (*see* Attachment AMI-3, Staff TS 3-9) shows an expansion in rate base from $346 million[8] at the end of 2019, plus a proposed $49 million[9] in actual investments in 2020, plus an *additional* $400 million in planned investments for 2021 through 2025, yet only 15% of its $400 million budget is growth-related and a lion's share of the non-growth, non-revenue-producing projects are discretionary. These amounts raise the question about Liberty's planning process, and management decisions – whether *doubling* the rate base in five years (while only 15% of that

[8] *See* Bates II-132R, line 1.

[9] *See* Staff TS 3-31.

investment is growth related) is a sound approach and beneficial for customers or in the public interest.

When this case was filed in July 2020, Liberty presented its "integrated capital spending plan" as Attachment BF/RM/HT-2, (Bates II-189) which showed projected spending as: 2021 at $34.7M; 2022 at $54.1M; and 2023 at $53.4M. In Data Response OCA 3-8, Liberty stated that its capital budget was: 2021 - $49M; 2022 -$38M, and 2023 - $59M. Then in February 2021, in Response Staff TS 3-9 (*see* Attachment AMI-3), the Company provided a revised capital budget for the next 5 years which showed the capital budget as follows: 2021 - $48M; 2022 - $111M; 2023 - $74; 2024- $93.5M; 2025 - $75M. Without any explanation, Liberty's capital budget has practically doubled since this case was filed.

Based on the last CIBS filing (DG 20-049, Attachment CAM-1) the average CIBS investment was $4.6 million per year. Since the last rate case, the average was $10 million per year. The proposed step adjustment asked for a recovery of 80% of the non-growth capital investments which translates to an average $54 million per year based on the latest capital budget described earlier. It is more than ten times the average CIBS investment. Even 20% of the non-growth capital investment (equivalent to $13.5 million per year) is more than the average CIBS investment of the last few years.

The OCA fundamentally questions whether such enormous increases in rate base are necessary. Such large increases in capital will exacerbate any inherent regulatory lag, but the OCA questions whether such large budgets with a huge non-growth discretionary investment are appropriate for a rate plan involving a series of step increases as opposed to traditional rate review and recovery through test-year based rate setting.

Other Issues

Q. Do you have any observations regarding any inaccuracies or errors that might impact the Company's decision to file this rate case?

A. I will address several issues regarding the Company's decision to file this rate case. The first issue is related to the low-income discount program. The second issue is related to the Company's treatment of decoupling that impacted its rate request. As this is the first rate case filing that Liberty has made since implementing the decoupling mechanism, the Company, Staff and the OCA worked together to address these issues through a settlement agreement in the temporary rates phase of this proceeding approved by the Commission.

Q. Before discussing the issues, please explain how revenue requirement, revenue collected, and allowed revenues are different in a traditional rate filing as compared to a rate filing made after a decoupling mechanism has been implemented.

A. Traditionally, any increase of revenue requirement allowed is added to a company's test year revenue when setting the new rates. If a company had $1,000 in test year revenues and demonstrated a need to collect an additional $300, then the company would design base rates to collect $1,300. That is no longer true under decoupling. Decoupling involves two versions of revenue: a) the revenue actually collected at current rates, and b) the allowed revenue that the company can retain under decoupling. Decoupling creates a separation between the revenue actually collected and the allowed revenue. The difference that is either returned to or collected from customers is identified by the company as "decoupling revenue" which could be surplus or deficit in any given year. In traditional rate filings, there is no such separation between the revenue actually collected and the allowed revenue. Under decoupling, in a rate case, if current rates collected more revenue than the company was allowed, and there was no revenue deficiency due to other factors (such as plant increases or O&M increases), the rate case would reduce revenues though reduced rates. If there is an increase in revenue requirement, and it is equal to the "decoupling revenue," there would not be any change in rates (the base rate increase would be offset by the decoupling mechanism decrease). Only if the increase in revenue requirement is higher than the decoupling revenue would there be an overall rate increase.

Q. Can you now please elaborate on the two issues?

A. In its initial filings, the Company calculated its revenue increase based on its allowed revenue and applied the increase to the revenues collected at current rates. (*See* Petition Attachment 1, pp. 2-4.) This did not take into account that the current rates provide for a revenue collection above the allowed revenue. However, the request for an increase in revenue requirement must take into account *all* the revenues that are being collected under the current rates. The Company's filing had two mistakes: 1) the revenue amount under current rates did not reflect the revenues from the Residential Low Income Assistance Program (RLIAP),[10] and 2) the

[10] Currently known as the Gas Assistance Program (GAP).

Company translated an increase in revenue requirement directly to an increase in rates which incorrectly did not take into account that the current rates provide for a revenue collection above the allowed revenue, the difference that would have been returned to customers through the RDAF.

Q. Please explain the first issue.

A. The first issue is related to the low-income discount program. The Company collects low-income program discounts from all customers through the RLIAP as part of the LDAC. As a result, the Company's revenue is made whole when both the base rate and the LDAC collection of this discount are considered. However, in its initial rate filing in this case, the Company did not account for the low income discount revenue recouped through the RLIAP/ LDAC when calculating its required distribution revenue (revenue requirement).[11] Thus, to begin with, the Company missed approximately $2 million in revenue in its earning calculations, rate of return, revenue increase required, etc. Inexplicably, the Company made mistakes in the rate model which resulted in an additional increase in the revenue requirement by the same amount. These errors reflected a roughly $4 million impact.[12] Such a large figure might have influenced the Company's decision to file a rate case.[13]

[11] This created a bigger issue in the rate design model which is discussed later.

[12] The $4 million amount is significantly more than the $0.9 million adjustment due to customer reclassification, which was stated as one of the reasons for the rate case.

[13] This error was corrected in the February 21, 2021 by the Company through an updated report of proposed rate changes and updated attachments. *See* Tab 32.

Q. Do you have any recommendations to correct this issue in the future?

A. Yes. The source of these errors is the integration of low-income discounts in the rate design model. I recommend that the Company treat all low-income customers as regular customers for all rates and revenue related matters, and reconcile the discount through the LDAC. First, all electric utilities and the one other gas utility in the state follow this methodology for their low income program-discounts costs and rate design and have not made similar errors in revenue calculations. Secondly, with the changes implemented in the recent low income program docket (DG 20-013), the discount is no longer offered year-round; instead, it is offered only for the winter season, and the discount now also applies to the supply portion of the bill (whereas before it was limited to the distribution portion). This approach would eliminate the possibility of errors in the complexity of rate design modeling, and would make it be easier to address program costs through the LDAC.

Q. Are you proposing to eliminate Rates-4 or low-income rates?

A. No. I am proposing to change the way those rates are presented in the rate design process. For rate design, R-4 (low-income) customers would be recognized at regular customer rates, and the Company will count the regular rates as revenue for rate design purposes. The discount will be given to the customers and the recoupment of that discount from all other customers will be accomplished through the LDAC.

Q. Please explain the second issue.

A. The second issue is more nuanced and new under decoupling. If there is an overcollection above allowed revenue, the Company returns the excess revenue through its approved decoupling mechanism, the RDAF. In a decoupled environment, when there is a rate case the over-collection can be credited towards the required rate increase so that the revenue requirement is increased without changing the base distribution rates. As a result, the RDAF mechanism will be reset. So without increasing the distribution rates, the Company's revenue can be increased. This is accomplished by changing the revenue per customer (RPC). RPC calculations should be filed as part of the tariff compliance filing.

Q. Has this adjustment been done before?

A. Yes. That is what was done (at Staff's recommendation) in the temporary rate phase of this proceeding, *see* DG 20-105 Exhibits 5 and 6, where adjusted decoupling RPCs and usage per customer (UPC) were implemented. For the settlement agreement in the temporary rates phase the Company proposed and the Parties agreed to use current rates as temporary rates to provide a temporary allowed revenue increase. By increasing the allowed revenue in temporary rates by maintaining current rates, customers did not see an increase in rates but they also were no longer receiving the refund they would have received under the RDAF.

Q. Do you think the approach taken in the temporary rates settlement agreement regarding decoupling should be replicated in the future?

A. No. The OCA believes that the implementation of this method, which involved changing the usage per customer (UPC) during the temporary rates phase, is inappropriate. The UPC is part of what the rate case determines and it is premature to make that judgement at the temporary rate phase because, to analyze the UPC properly, stakeholders need more time than the temporary rate phase allows. In the future, rate increases at the temporary rate phase should only be accomplished through a change in the RPC as occurs during CIBS or a step increase.

Q. Please explain the rate design model issue you mentioned earlier.

A. As discussed earlier, in its Rates-5 rate design schedule the Company did not include the approximately $2 million in revenue that it collected through the LDAC. This oversight has two layers of impacts: 1) it inflates the required revenue increase, and 2) the revenue increase, applied to the deflated current revenue as the base, produces a higher percentage, which is then applied to the actual revenue when designing rates. For example, if the actual revenue is $100, and the low income program discount is $2, the Company is counting $98 for rate design and all other rate case filing purposes. If we assume that a cost of service study shows a required revenue of $105, then the rates model will show a revenue increase of $7 ($105 -$98) needed, as compared to the actual required increase of $5 (($105 -$100), with a difference of $2. This is the first layer. When the percentage increase is calculated, the model uses $98 as the base and $7 as the revenue increase, which is 7.14%. Then the Company applies this percentage to its actual current revenue of $100, giving them a revenue of $107.14, whereas it should be $105. In actuality, only a 5% increase was required.

In Docket DG 17-048, and in the initial filing in this case, the Company added another wrinkle in its Rates-5 schedule. Specifically, the Company added the low income program amount above the approved revenue increase. Continuing the example I have been using, assuming that the Commission approved the $7 revenue increase (incorrectly), the Company added another $2 to that revenue to recover the 'low-income program cost' so that the Rates-5 schedule would reflect a revenue increase of $9. Using the example previously given, the calculations will produce revenue of $109.2, instead of the $105.00 if everything were done correctly. Unfortunately, this mistake is what occurred in the last rate case DG 17-048 resulting in an increase in revenue currently reflected in the test year allowed revenue.

Q. Did the Company correct these issues in its updated filing?

A. Yes. Liberty updated its rate filing on February 25, 2021, which corrected how revenues under decoupling and the low-income discount program are accounted for when calculating revenue requirements, and designing rates, under a decoupling mechanism environment.

Q. Do you have any additional observation on the updated filing?

A. Yes. The updated filing requests an increase in delivery rates equivalent to $2.9 million by allocating $2 million to the production costs recovered in the Cost of Gas filings. In its original filing this $2 million was part of delivery rates. As our colleague Jerome Mierzwa has testified, the OCA agrees with this shift based on the functional cost of service study. This is still a proposed $4.9 million overall increase in rates.

The Company proposed revenue requirement increase, relative to the previously allowed revenue requirement, is actually $9.9 million which is the $4.9 million delivery and COG rate increases I just mentioned plus the of $4.97 million "decoupling revenue" increase implemented during the temporary rate phase.

Conclusion

Q. Please summarize your position?

A. In summary, OCA recommends the following:

- The OCA recommends that the amortization of reserve deficiency approved in the last rate case be discontinued until the ASL and COR are revised and a new depreciation study is done.
- On the rate plan issue, the OCA is concerned about the balance between growth and non-growth capital investment by the company, and recommends that any rate plan should incorporate a reasonable balance.
- The OCA recommends that the low-income rate class should be treated as regular residential customers in all rate design and revenue related purposes, and the low-income program cost should be dealt with in the cost of gas or any related dockets.
- The OCA recommends that in the future the UPC should not be changed during the temporary rate phase.
- The OCA recommends that the RPC calculations be filed as part of the tariff compliance filing.

Q. Does that conclude your testimony?

A. Yes.

Attachments

Appendix A

Educational and Professional Background

Al-Azad Iqbal

I am employed by the New Hampshire Office of the Consumer Advocate as the Economics/Finance Director. My business address is 21 S. Fruit Street, Suite 18, Concord New Hampshire, 03301.

I received my Bachelor degree in Architecture (B. Arch) from Bangladesh University of Engineering and Technology. Later, I received my Masters (MS) in Environmental Management from Asian Institute of Technology and another Masters in City and Regional Planning (MCRP) from the Ohio State University. I was a Doctoral Candidate at the City and Regional Planning Department at the Ohio State University. After joining the PUC in 2007, I participated in several utility related training courses including marginal cost training by National Economic Research Associates (NERA), Advanced Regulatory Studies through the Institute of Public Utilities at Michigan State University, and Depreciation Training with the Society of Depreciation Professionals. On March 12, 2021 I joined the Office of the Consumer Advocate as the Economics/Finance Director.

Prior to joining the PUC, I was involved in teaching and research activities in different academic and research organizations. Most of my research work was related to quantitative analysis of regional and environmental issues.

M E M O R A N D U M

TO: **Peter Dawes**, Vice President, Finance and Administration
Energy North Natural Gas ("ENNG" or the "Company") d/b/a Liberty Utilities

FROM: **Gregg Therrien**
Concentric Energy Advisors, Inc. ("Concentric" or "CEA")

CC: **Steve Mullen** (ENNG), **James Bonner** (ENNG), **Chris Wall** (CEA), **Peter Hoegler** (CEA)

DATE: August 8, 2019

RE: **Review of ENNG's Revenue Decoupling Mechanism**

SECTION I. EXECUTIVE SUMMARY

ENNG has engaged Concentric to conduct an audit of its recently approved revenue decoupling mechanism ("RDM") because the actual RDM results to date have resulted in distribution revenues $1.4 million[1] below that allowed in the Company's last rate case.[2] Additionally, the RDM calculation has shown volatile results and has produced an unanticipated large credit to customers over the first seven months since the RDM has been in place.

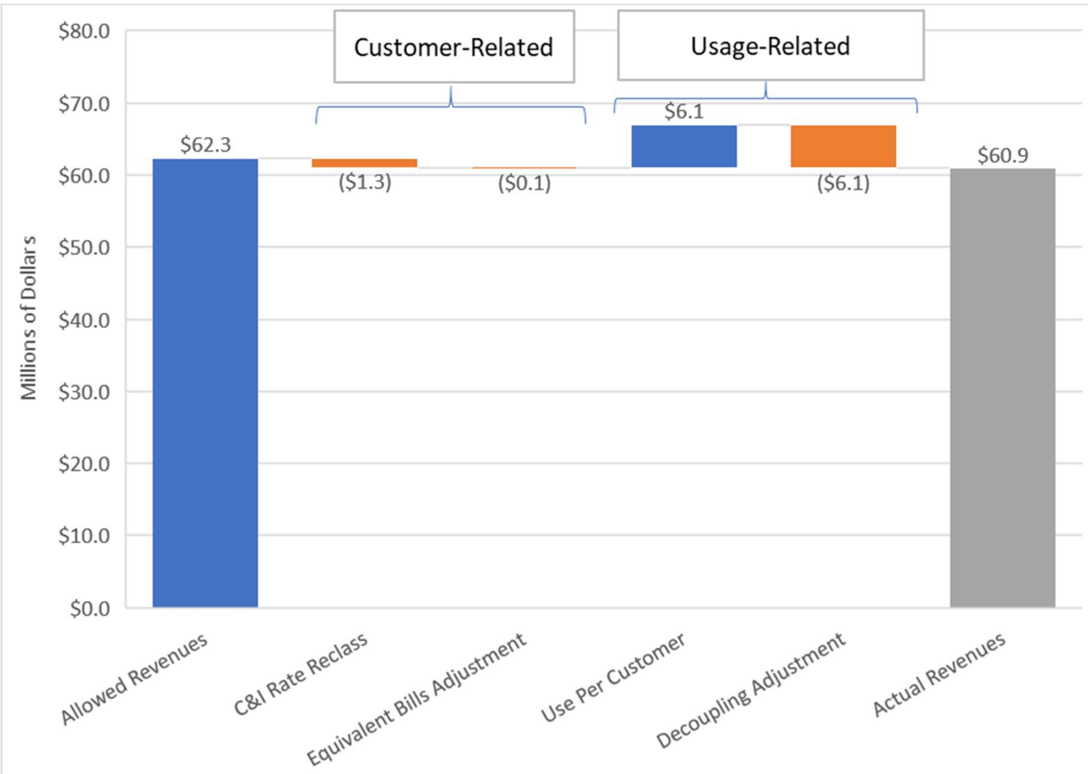
Concentric's findings are summarized as follows:

i. *The Company's RDM calculations are accurate.*
ii. *Actual class-level customer counts are significantly different than approved customer levels, resulting in a $1.4 million distribution revenue shortfall because:*
    a. *A Post-Test Year C&I customer reclass was not reflected in the rate case, and*
    b. *The New Hampshire Public Utilities Commission ("NHPUC") Staff made an "equivalent bills" adjustment in the rate case that makes attaining allowed revenues difficult.*
iii. *Increased use per customer is driving the large RDM credit.*
iv. *ENNG's use per customer trends are consistent with other regional natural gas companies.*
v. *The real-time weather normalization adjustment ("WNA") is now functioning properly after a $0.264 million error was discovered in November 2018 and subsequently credited back to customers in April 2019.*
vi. *The Company's unbilled revenue methodology is prone to higher monthly variation than other methods. Two minor errors in the seven months of entries also contributed to monthly decoupling entry variances.*

[1] For the period of November 2018 through May 2019.
[2] Docket No. 17-048 "Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities Distribution Service Rate Case", Final Decision dated April 27, 2018 (the "Final Decision").

The following chart summarizes the components of the variance between allowed and actual distribution revenues:

Chart 1: Components of Distribution Revenue Variance



The purpose of an RDM is to sever the link between sales units (usage) and revenues, thus enabling companies to freely promote conservation measures to their customers without suffering financial harm. A revenue per customer ("RPC") RDM construct is intended to recognize that adding new customers requires compensation to fund the incremental investment necessary to connect that customer to the distribution system. As such, an RPC RDM does not reconcile differences in customer counts.

The above chart shows that changes in customers compared to the approved rate year has resulted in an unfavorable margin variance of $1.4 million. This is primarily the result of two factors: 1) a February 2018 commercial and industrial ("C&I") rate review, which resulted in a significant reclassification of customers among the C&I rate schedules, and 2) a late adjustment to target (allowed) distribution revenues and customer counts ("equivalent bills") by the NHPUC Staff at the end of the rate case proceeding.

The $6.1 million favorable margin variance related to higher use per customer is properly captured through the RDM and nets to zero.

SECTION II. BACKGROUND

ENNG has engaged Concentric to conduct an audit of its recently approved RDM because the actual RDM results to date have resulted in distribution revenues $1.4 million below that allowed in the Company's last rate case. Additionally, the RDM calculation has shown volatile results and has produced an unanticipated large credit to customers over the first seven months since the RDM has been in place. The large RDM credit is unanticipated because the "real time" WNA is billed monthly on each customer's bill, thereby eliminating the largest anticipated variance component of the RDM, weather. Concentric first produced a work plan to address the primary purpose of this engagement, which is to determine whether there are any structural deficiencies in the RDM construct.

The details of this work plan consist of the following:

1. *Verify that the RDM is functioning properly, through investigation of the following:*
    i. *That the Allowed Revenue Per Customer being used in the RDM calculation is accurate and consistent with the approved billing determinants and allowed revenues from the rate case;*
    ii. *That the Actual Revenue Per Customer ("RPC") since inception of the RDM is also calculated correctly, and*
    iii. *That Concentric's independently calculated monthly RDM variances are equal to that recorded by the Company.*
2. *Quantify the monthly variances by category (i.e., customer-related and usage related);*
3. *Calculate the monthly weather-related variance and compare that result to actual billed WNA revenues;*
4. *Validate the monthly unbilled entries, and quantify the unbilled contribution to monthly variances, and*
5. *Summarize our audit findings and provide Concentric's recommendations.*

SECTION III. THE ENNG VARIANCE ANALYSIS

The Company provided Concentric with its monthly decoupling values as well as its variances to allowed distribution revenues. This is summarized as follows:

Table 1: Variance to Allowed Distribution Revenues (November 2018 – May 2019)

Line	Revenue Type	Total
1	Allowed Distribution Revenues	62,292,497
2	Actual Distribution Revenues	60,930,806
3	Difference	(1,361,691)
4	Decoupling Deferral[1]	(6,089,952)

1 Included in Line 2 above.

As Table 1 indicates, cumulative actual revenues (inclusive of the decoupling adjustment) are below allowed by $1.4 million. This significant unfavorable variance, coupled with the larger than anticipated decoupling adjustment, led to this audit to ensure the RDM is functioning properly and that the base revenue target RPC is appropriate and calculated consistent with the Final Decision.

SECTION IV. PRELIMINARY RESULTS

On July 12, 2019 Concentric reviewed a Microsoft PowerPoint© presentation with ENNG Management. This presentation included the following preliminary findings:

- The Company's RDM calculations are accurate.
    - Target RPC, by class and in total, are calculated correctly;
    - Actual Calendar Revenues cannot be calculated on a Class RPC basis because of the system-wide unbilled methodology, and
    - The method used to calculate the decoupling adjustment is different than the approved tariff methodology, but mathematically should yield the same result.
- Actual customer counts are below Allowed levels, primarily in the Commercial and Industrial ("C&I") rate classes result in a $0.7 million[3] delivery revenue shortfall that is not recoverable through decoupling.
- Use Per Customer Growth drives the higher than anticipated decoupling credits.
- The unbilled calculation contributes significantly to the monthly variances, making it difficult to assess the true impact of the decoupling adjustment.

As a result of this presentation Concentric was asked to further investigate use per customer trends from other New England gas companies. The above findings have been validated and refined, and now also include the requested use per customer comparisons.

SECTION V. FINAL FINDINGS

A. The Company's RDM calculations are accurate.

Concentric validated the Company's monthly RDM calculations by performing three tests:

1. *Replicate the monthly Target RPC;*
2. *Validate the Company's monthly Actual RPC, and*
3. *Compare the differences from steps 1 and 2 to the Company's reported monthly decoupling amounts.*

These steps require a review of the Company's unbilled methodology and monthly entries, which are necessary to report monthly revenues on a calendar basis.

The first audit test was to validate that the monthly RPC targets were calculated correctly using class-specific data from the Final Decision. CEA first obtained the final approved billing determinants from the Final Decision, which includes the number of customers (equivalent bills), throughput (therms), and the appropriate tariff's monthly fixed charges and delivery rates per therm. We then multiplied these billing determinants by the tariff rates to derive monthly allowed distribution revenues by rate class. Each class-specific distribution revenue was then divided by the allowed number of equivalent bills to derive class-

[3] Concentric's preliminary finding used customer rates to quantify the customer variance. The final analysis contained in this memorandum properly uses the class RPC values, which are used in the RDM calculation.

specific revenue per customer targets. Lastly, these revenue per customer targets were compared to the Company's RDM calculation workbook and were found to tie out in each class for each month.

The second step was to validate the Company's Actual RPC calculations. This was performed in total rather than at the class level because of the nature of the unbilled calculation (discussed below in Section VII). Unbilled is calculated by first using actual system gate station receipts less company use, daily metered volumes[4] and a lost-and-unaccounted-for deduction[5] pertaining to local delivery system losses. Because the Company utilizes the "gate station approach" to estimate unbilled sales, class-level detail is not possible. Therefore, Concentric reviewed both the class-specific billed revenues, the unbilled revenue estimate and the calculation of monthly equivalent bills to validate the monthly Actual revenues.

Concentric's review of the underlying billing data and unbilled entries did uncover a minor unbilled estimation error whereby the number of equivalent bills used in the unbilled calculation were incorrect for the months of November 2018 through and including March 2019[6]. This error has no effect on the seven-month cumulative variance, as the unbilled accruals are reversed each month and the equivalent bills error was corrected in the April 2019 accrual. Concentric then performed a second reasonableness test whereby the unbilled sales volumes and equivalent bills were spread to the rate classes based on billed volume percentages. This provided a "sanity check" calculation, which showed material volatility in the C&I classes. The root cause of this volatility is discussed below.

The third step compares the actual RPC to the Allowed RPC and multiplied times the number of calendar month equivalent bills. This calculation yielded a decoupling value very close to the Company's recorded decoupling revenues in total, but significant monthly variances in the months of November 2018 through March 2019.

A. Customer counts are significantly different than that allowed in the rate case.

Average customers for the period of November 2018 through May 2018 were compared to the 2016 rate year for each rate class. The variance in customer counts was then multiplied times the Allowed RPC for the same period. This calculation is shown below:

[4] Daily metered volumes are excluded from the unbilled calculation as they are billed on a true calendar basis.

[5] The Company utilizes a 1.6% lost-and-unaccounted-for percentage in all months. No attempts were made by Concentric to validate this assumption.

[6] Actual cycle-based number of bills was inadvertently used in these five months.

Table 2: Distribution Revenue Impact Related to Average Customer Counts

	Average Customer Counts			Distribution Revenue	
Rate Class	**Actual**	**Rate Year**	**Actual Versus Rate Year**	**Allowed RPC 11/2018 through 5/2019**	**Rate Year Variance**
R-1	3,133	3,558	(425)	$167	($70,804)
R-3	72,472	72,142	330	$458	$151,279
R-4	5,906	5,315	592	$177	$104,676
R-5	64	-	64	$217	$13,882
R-6	185	-	185	$596	$110,225
R-7	3	-	3	$230	$707
Total Residential	**81,763**	**81,015**	**749**		**$309,964**
G-41	9,200	9,147	53	$1,117	$58,864
G-42	1,379	1,755	(376)	$6,515	($2,448,421)
G-43	58	48	10	$43,278	$432,051
G-44	2	-	2	$1,452	$2,317
G-45	4	-	4	$8,469	$36,216
G-46	-	-	-	$56,262	$0
G-51	1,227	1,360	(133)	$810	($107,489)
G-52	374	325	49	$4,085	$199,787
G-53	36	32	4	$34,929	$151,109
G-54	28	26	2	$25,621	$52,094
G-55	3	-	3	$1,053	$2,909
G-56	-	-	-	$5,311	$0
G-57	-	-	-	$45,408	$0
G-58	1	-	1	$33,307	$36,320
Total C&I	**3,109**	**3,546**	**(437)**		**($1,682,336)**
Total All	**84,872**	**84,561**	**311**		**($1,372,372)**

As the above table indicates, the total difference in customer counts is the source of the difference between Actual and Allowed distribution revenues.

a. A Post-Test Year C&I Customer Reclass was not Included in the Decoupling Targets.

In February 2018 the Company analyzed its C&I rate classes to determine if any customers were not properly assigned to the appropriate rate class. For example, if a commercial customer has been receiving service under Rate G-41 (with an availability requirement that the customer must use less than 10,000 therms annually and use more than 67% of its annual usage in the winter months) and, as a result of the annual rate review it is determined that the customer has increased its annual usage above 10,000 therms, the customer is then reclassified to the G-42 rate schedule.

Concentric's review of current customer counts compared to that imputed into allowed revenues showed significant variation, particularly in the C&I class. We determined that the C&I rate review conducted in February 2017 was not accounted for in the rate case. The summary of these customer reclasses is as follows:

Table 3: February 2017 C&I Rate Reclassifications

Rate Class	C&I Customer Reclass				
	Out	In	Net	11/2018 - 5/2019 Allowed RPC	Delivery Revenue Impact
G-41	(489)	789	300	$1,117	$335,148
G-42	(529)	241	(288)	$6,515	($1,876,269)
G-43	(18)	17	(1)	$43,278	($43,278)
G-51	(437)	358	(79)	$810	($64,015)
G-52	(97)	162	65	$4,085	$265,532
G-53	(10)	15	5	$34,929	$174,647
G-54	(9)	7	(2)	$25,621	($51,241)
Total	**(1,589)**	**1,589**	-		**($1,259,476)**

This variance is a subset of the total customer-related margin variance calculated in Table 2.

b. Test Year Adjustments Included in the Decoupling Targets Makes Attaining Imputed Customer Counts Difficult.

Near the completion of the litigated rate case in Docket No. 17-048 the Commission Staff required the Company to make a calendarization adjustment for the number of test year bills. This adjustment is intended to "normalize" the test year customer counts and reflect new customer accounts added during the test year. The Company's approach to this request was to calculate an equivalent bills adjustment, which both smoothed test year customer counts and recognized new customer additions made during the test year. This adjustment resulted in the following increase to Allowed customer counts, therms and revenues:

Table 4: Rate Year Equivalent Bills Adjustment

Rate Class	Annual Bills	Annual Therms	Delivery Revenues
R-1	386	7,154	$8,475
R-3	14,336	1,043,363	$789,374
R-4	(1,580)	(214,472)	($56,689)
Total Residential	**13,142**	**836,045**	**$741,160**
G-41	3,214	485,913	$342,087
G-42	343	561,680	$238,682
G-43	(28)	(554,018)	($138,357)
G-51	99	14,201	$8,535
G-52	79	155,599	$40,388
G-53	(21)	(544,071)	($96,774)
G-54	(16)	(836,835)	($47,439)
Total C/I	**3,670**	**(717,529)**	**$347,123**
Total All	**16,812**	**118,516**	**$1,088,283**

The above adjustment is included in the Approved RPC targets resulting in a higher customer count that must be attained to achieve allowed delivery revenues. The RDM adjustment does not compensate the Company for lower actual customer counts than that imputed into base delivery revenues. The RDM is designed to sever the link between sales (therms) and revenues, not customer counts.

B. Use Per Customer

Again, the purpose of the RDM is to sever the link between customer usage and delivery revenues. Reasons for usage variances are primarily the result of colder or warmer than normal weather, conservation measures (from both ratepayer-funded programs and individual customer conservation measures) and economic activity. Given the Company's RDM construct that includes a real-time WNA, the variances related to use per customer were anticipated to be small. To the contrary, the decoupling revenue adjustment has credited customers $6.1 million over the first seven months of operation. The real-time WNA has properly captured the weather-related variance (discussed in Section VI below), which leaves the entire RDM adjustment attributable to use per customer. The increase in use per customer has occurred in both the Residential and C&I sectors:

Chart 2: Residential Use Per Customer

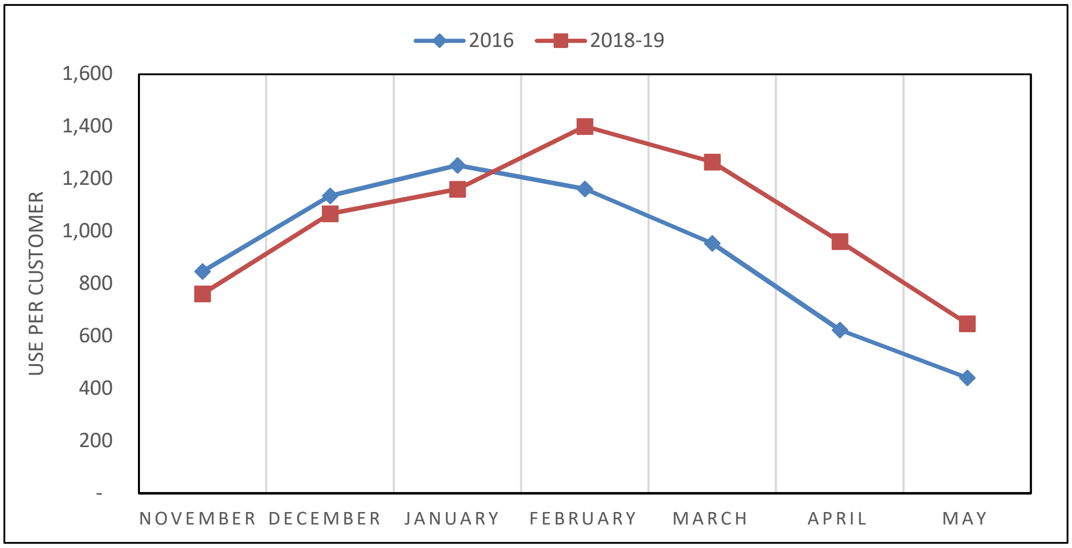
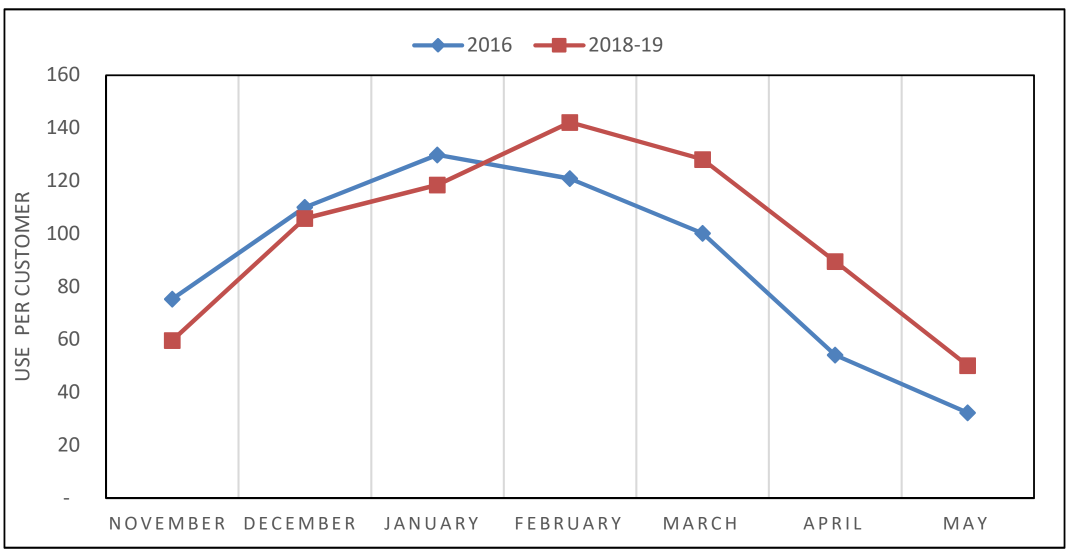


Chart 3: C&I Use Per Customer



At the preliminary findings presentation, the Company was surprised by the recent increase in UPC, particularly for the Residential class. Concentric was asked to compare ENNG's UPC to that of neighboring natural gas utilities. Concentric was able to obtain customer and usage data from the following companies[7]:

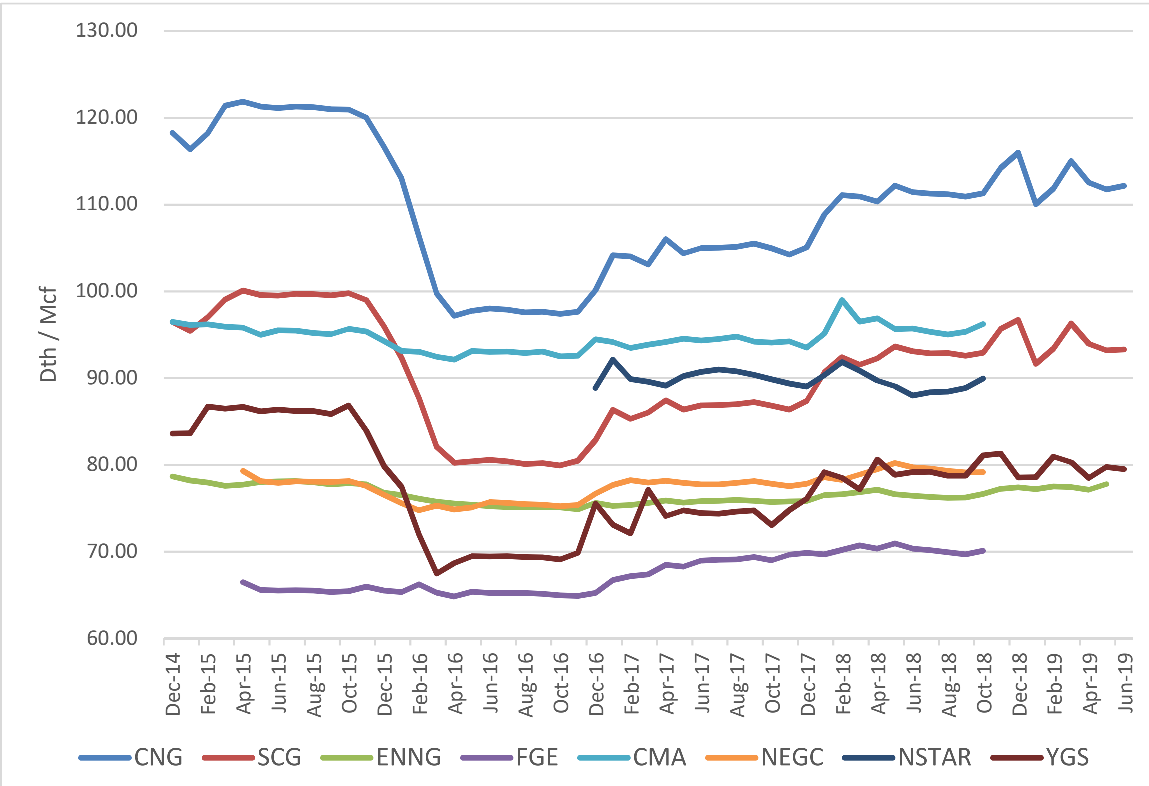
[7] This portion of the memorandum will be shared with the list of participants in recognition of their voluntary involvement in the study.

Table 7: Participating Local Gas Distribution Companies ("LDCs")

Utility	Abbreviation	Location	Approximate Number of Customers
Connecticut Natural Gas	CNG	Greater Hartford, CT and Greenwich, CT	180,000
Columbia Gas – MA	CMA	Springfield and Laurence, MA	325,000
Eversource Gas – MA	NSTAR	Central MA	290,000
Liberty – NH	ENNG	New Hampshire	95,000
National Grid – RI	NEGC	Rhode Island	55,000
The Southern Connecticut Gas Company	SCG	Greater New Haven and Bridgeport, CT	200,000
Unitil – MA	FGE	Fitchburg, MA	16,000
Eversource – CT	YGS	Across CT	200,000

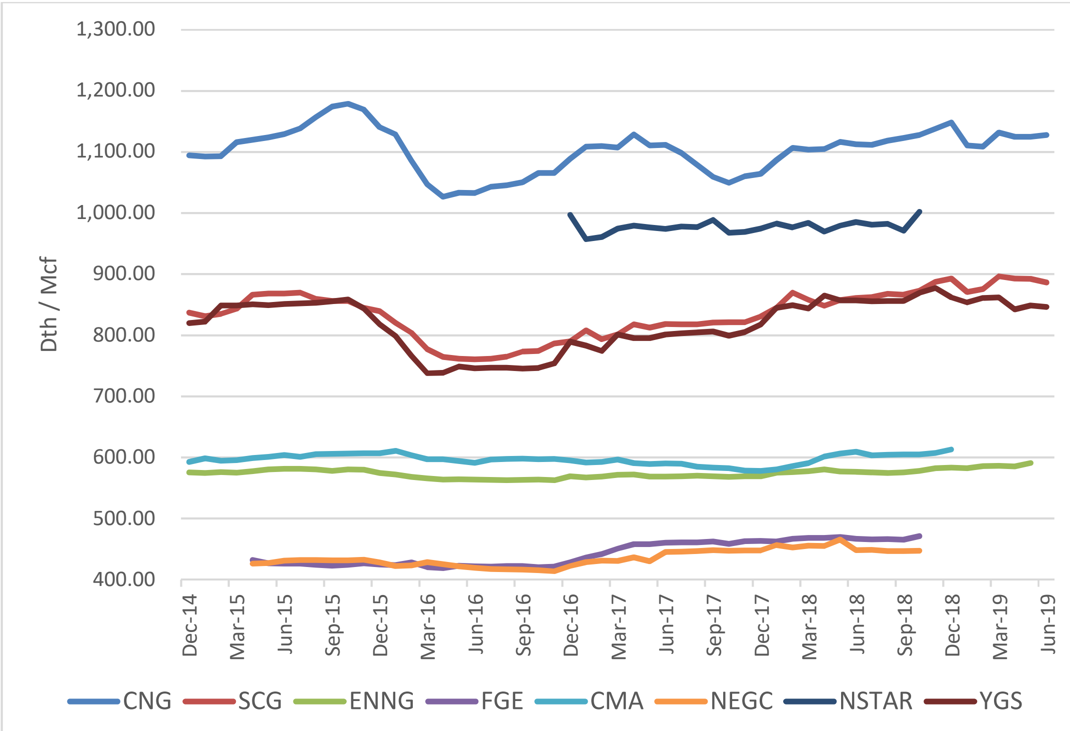
Monthly customer and usage data was obtained by rate class for as far back as January 2014. Concentric then calculated monthly UPC, then calculated a 12-month rolling total. Normalized consumption data was used where available. The data below represents summarized data for Residential (heat and non-heat), Commercial and Industrial customer classes.

Chart 4: Residential Use Per Customer Trends: 12-Month Rolling Total



The CNG, SCG and YGS trend lines are difficult to compare because only actual usage data was provided while all other survey respondents included both actual and normalized volumes. Still, the trend over the most recent three years is consistent with other LDCs.

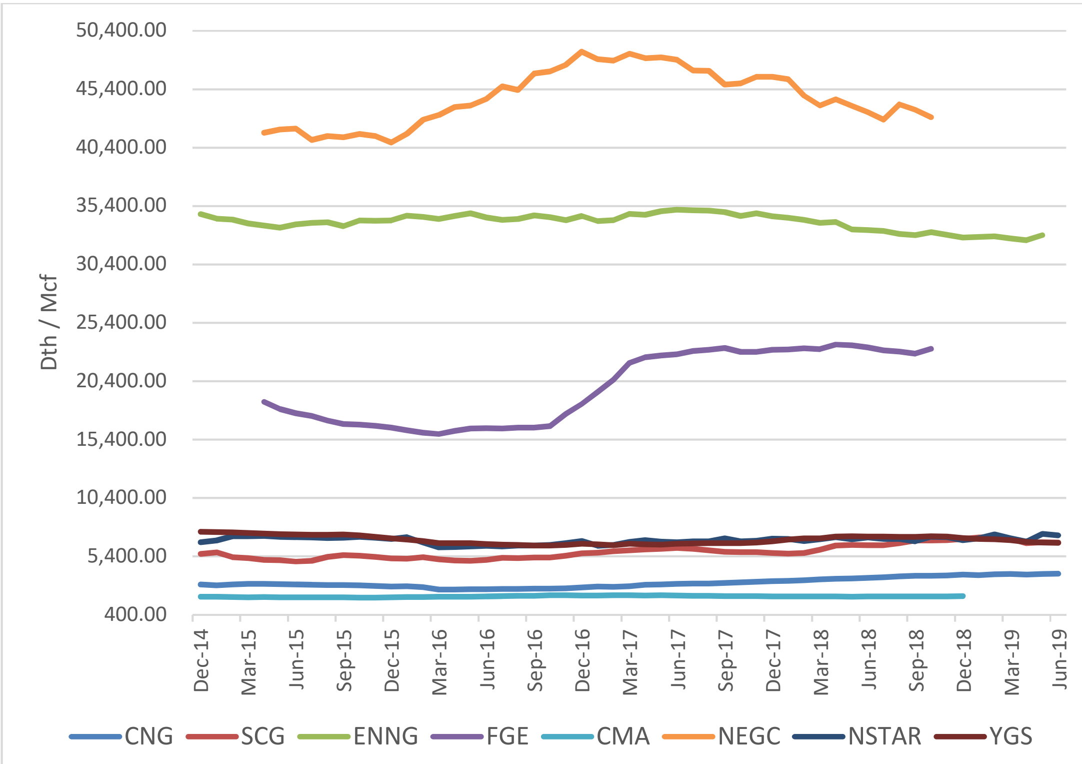
Chart 5: Commercial Use Per Customer[8] Trends: 12-Month Rolling Total



The Commercial trend exhibits a small upward trend for all LDCs except CMA, ENNG and NSTAR.

[8] NSTAR Gas represents a combined C&I UPC.

Chart 6: Industrial Use Per Customer Trends: 12-Month Rolling Total



The industrial class comparison is complicated by the fact that some of the utilities have appreciably different rate designs. For example, CNG, SCG and YGS's Industrial customers are served primarily under Rate LGS – Large General Service. This tariff does not carry a load factor distinction like the other participating LDCs tariffs. As such, the average UPC for these three LDCs appear much lower than those with more granular rate structures.

Appendix A contains individual use per customer graphs for each LDC.

SECTION VI. WEATHER VARIANCES AND THE REAL-TIME WNA

One of the audit tasks is to validate the accuracy of the real-time WNA adjustment. The real-time WNA is a customer-specific calculation that results in either a charge (when weather is warmer than normal) or a credit (when weather is colder than normal). The WNA is billed in the month in which the weather variance occurs, thus matching the charge or credit with the weather-related impact on the bill. Customer WNA billings is captured as a separate revenue component in the Company's revenue reporting, enabling a comparison between what was billed and what a class-level spreadsheet analysis produces. This comparison, although not expected to match perfectly, should indicate that the WNA is functioning properly or not. The results of the comparison between the real-time WNA and the Excel© based weather analysis is as follows:

Table 5: Comparison of Calculated Weather-Related Variance to the Real-Time WNA

Category	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
Distribution Revenues	$6,176,999	$9,601,480	$12,370,924	$12,544,467	$11,461,724	$9,515,278	$6,468,216
Heating Degree Days	*Colder / (Warmer)*						
Actual HDD	601	983	1,085	1,160	1,059	710	415
Normal HDD	504	857	1,162	1,167	1,026	737	414
Difference	97	126	(77)	(8)	33	(27)	1
Variance %	19.3%	14.8%	-6.6%	-0.7%	3.2%	-3.7%	0.3%
Weather Variance	*(Credit) / Charge*						
Calculated WNA	($510,539)	($900,154)	$585,425	$61,848	($255,743)	$218,110	($7,368)
Billed WNA[1]	($65,581)	($926,070)	$568,805	$11,317	($172,550)	$414,250	$206,917
Difference	($444,958)	$25,916	$16,620	$50,531	($83,193)	($196,139)	($214,285)
% of Revenues							
Calculated Weather	-8.3%	-9.4%	4.7%	0.5%	-2.2%	2.3%	-0.1%
Billed WNA	-1.1%	-9.6%	4.6%	0.1%	-1.5%	4.4%	3.2%

Upon reviewing the above comparison, one would expect to see only a small monthly variation between the calculated WNA and the billed WNA. Further, the two methods should move in the same direction (both methods resulting in a credit, or both resulting in a debit). Additionally, the magnitude of the adjustment should reflect the difference in heating degree days ("HDD"). Concentric's findings is that each month from December 2018 through March 2019 appear reasonable, displaying a close correlation between methods.

The months of November 2018 and April 2019 showed material variances between actual billed WNA and the spreadsheet estimate. November has a significant amount of HDDs and the weather was significantly colder than normal (19.3% colder). This colder than normal HDD implies that customers would have their heating systems on for the majority of the month. The fact that the billed WNA was a comparatively small credit compared to the spreadsheet analysis (and weather was significantly colder than normal) indicates that there was likely a billing system issue. It is our understanding from the preliminary results meeting that there was in fact an implementation issue with the real-time WNA in November 2018 and a credit was subsequently applied in April 2019, which explains the variation in these two months.

SECTION VII. THE UNBILLED REVENUE METHODOLOGY AFFECTS THE RDM CALCULATION

Unbilled revenues reflect those sales that occurred in the calendar month but have yet to be billed to the customer. Accounting standards require companies to report revenues on a calendar basis. When companies such as ENNG utilize billing cycles, there is an inevitable mis-match between billed sales (which cross calendar months) and calendar sales. To remedy this mismatch, companies must estimate the value of these unbilled sales. There are three commonly used methods to estimate unbilled sales:

Method 1: Perform a system-wide calculation based on monthly actual gate station take data (the "send-out" method);

Method 2: Utilize a base-thermal methodology, which estimates unbilled revenues based on unbilled heating degree days (the "base-thermal" method), and

Method 3: Utilize actual end-of-month meter reads (the "AMI" method).

Of these three methods, ENNG utilizes method 1. This method is the simplest of the three as it relies on total gate station receipts and system-level adjustments to derive calendar sales. The shortcomings of this method is that results tend to be volatile across the months, and class-level detail is not estimated making variance analysis more difficult. Further, with an RDM that includes rate class revenue targets, performing the monthly RDM entry must be performed at the system level given the current method for unbilled estimation. This means that the Company's actual RDM calculation is different than its published tariff:

Table 6: RDM Methodology Comparison

Approved Tariff Methodology (RPC)	Actual Practice (Revenues)
Step 1: Calculate the difference between Actual RPC and Allowed RPC for each rate class	**Step 1**: Derive Allowed revenues by multiplying the Allowed RPC times the actual number of customers for each rate class and sum them
Step 2: Multiply the RPC differences derived in step 1 times the Actual number of customers in each rate class	**Step 2:** Compare Actual Revenues to Allowed Revenues derived in step 1
Step 3: The sum of the rate class revenue differences calculated in step 2 to derive the monthly decoupling adjustment	**Step 3**: Subtract Actual from Allowed revenues to derive the decoupling adjustment

Both methodologies result in the same decoupling adjustment amount. However, the lack of transparency to the class level for the RDM calculation makes variance analysis more difficult.

There was an error in the unbilled calculation in the months of November 2018 through April 2019. Billing cycle equivalent bills rather than calendar equivalent bills were inadvertently used in the unbilled calculation. This error contributed to significant monthly swings in the RDM revenues, as the mismatch in equivalent bills is captured by the RDM, which includes target RPC based on calendar equivalent bills. The monthly variations are as follows:

Table 7: Unbilled Equivalent Bills Error Impact on Monthly RDM Variation

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
Customer Difference	(3,107)	2,160	3,215	4,977	(4,342)	(99)	(98)
Allowed RPC	$85.90	$112.91	$127.12	$119.83	$102.87	$69.23	$49.68
Dollar Impact	($266,901)	$243,919	$408,697	$596,338	($446,641)	($6,856)	($4,868)
Contribution to Monthly Unbilled Variance	**($266,901)**	**$510,820**	**$164,779**	**$187,641**	**($1,042,979)**	**$439,785**	**$1,988**

Once the error was discovered and corrected in April 2019 the large variation ended.

SECTION VIII. RECOMMENDATIONS

Recommendation 1: Any C&I rate review must be incorporated into the adjusted (rate year) equivalent bills calculation, and do not perform any rate reviews between rate cases.

Recommendation 2: Consider switching to a base-thermal unbilled methodology. This change will require some up-front investment in spreadsheet development but should help smooth monthly variances. This method will enable the Company to calculate its RDM consistent with its approved tariff and help with monthly variance analysis.

Recommendation 3: The real-time WNA should continue to be audited in the Company's billing system, particularly in the months when it is being applied to prorated bills (November and May).

SECTION IX. CONTACT US

Please contact me if there are any questions regarding this memorandum, or if we can provide further assistance.

Regards,

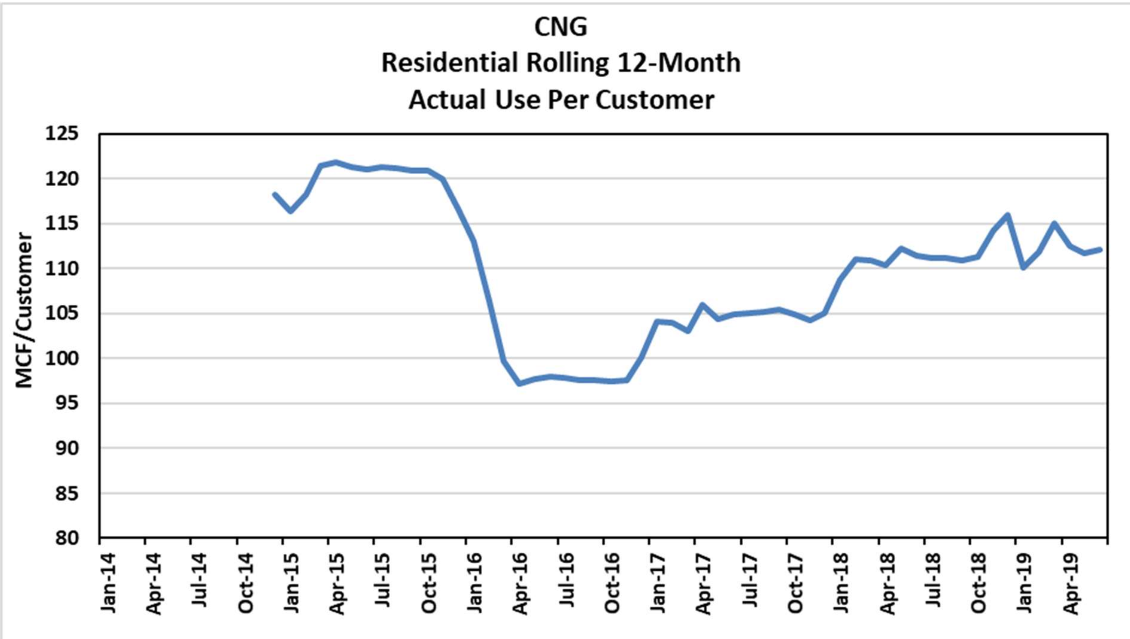
Gregg Therrien
Assistant Vice President
(508) 263-6284

APPENDIX A

DETAILED USE PER CUSTOMER CHARTS

PARTICIPATING LDCS

CNG


CNG
Residential Rolling 12-Month
Actual Use Per Customer
MCF/Customer
125
120
115
110
105
100
95
90
85
80
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
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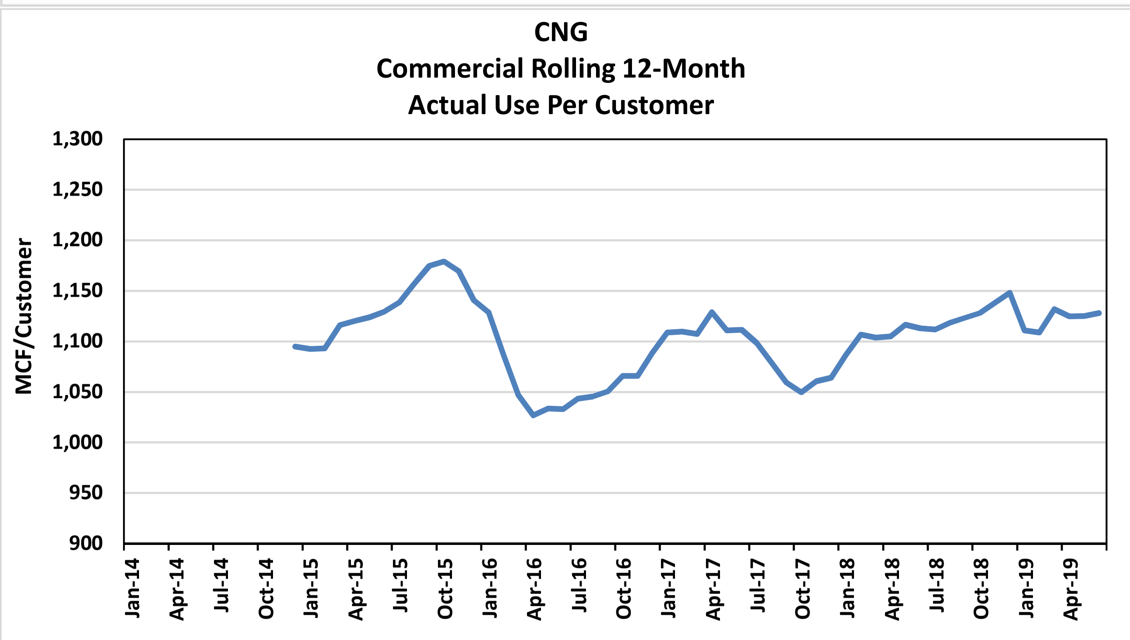
CNG
Commercial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
1,300
1,250
1,200
1,150
1,100
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1,000
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900
Jan-14
Apr-14
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Oct-14
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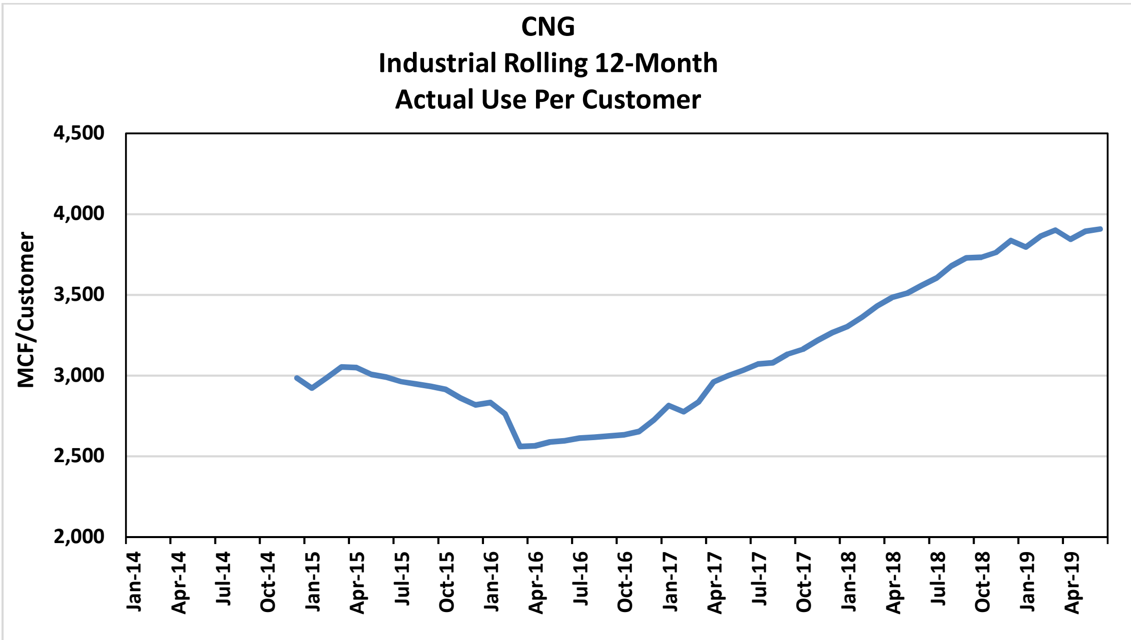
CNG
Industrial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
4,500
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3,500
3,000
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2,000
Jan-14
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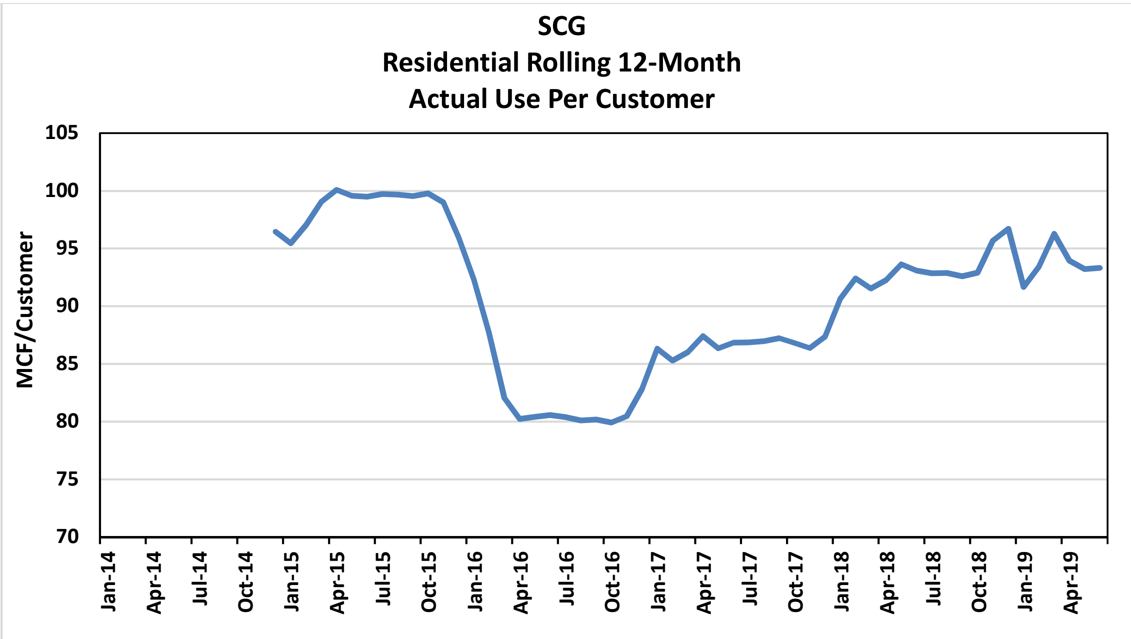
SCG


SCG
Residential Rolling 12-Month
Actual Use Per Customer
MCF/Customer
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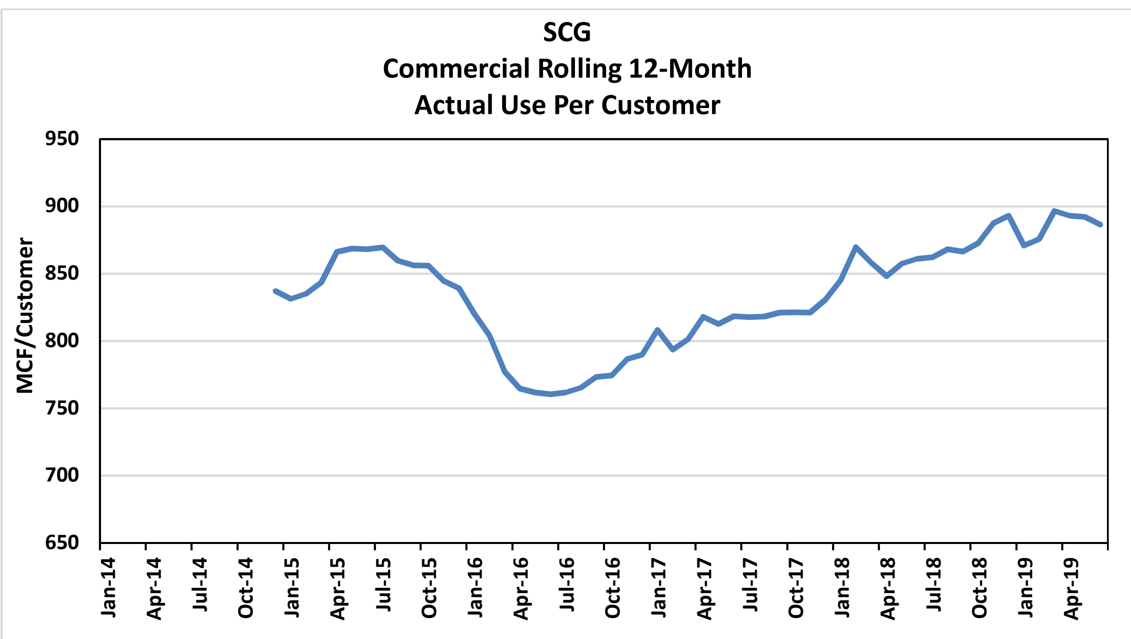
SCG
Commercial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
950
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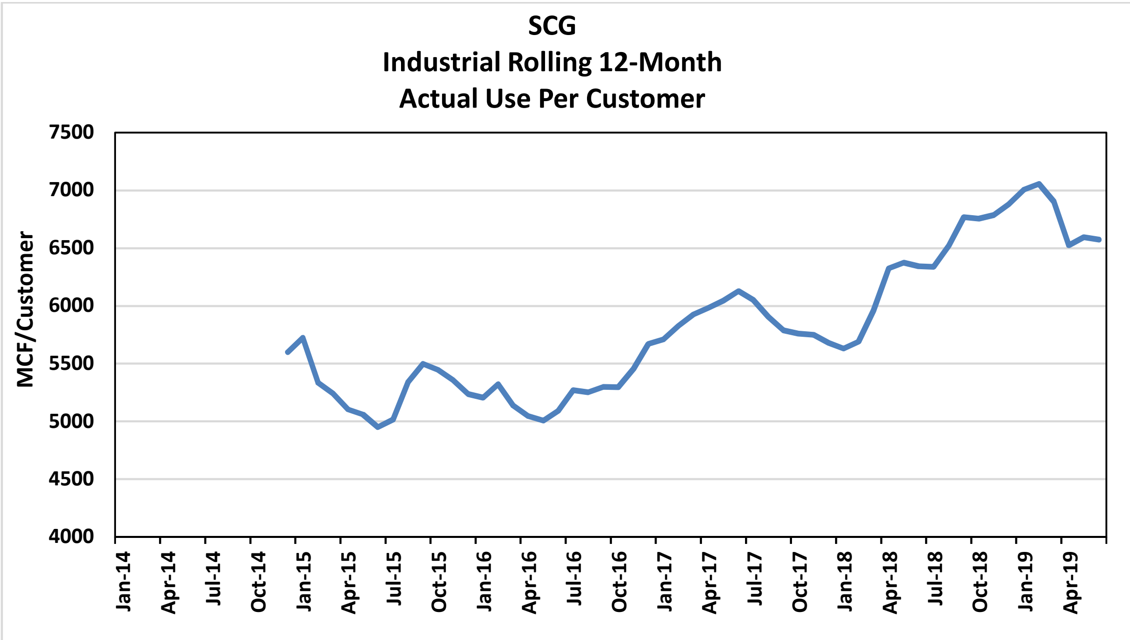
SCG
Industrial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
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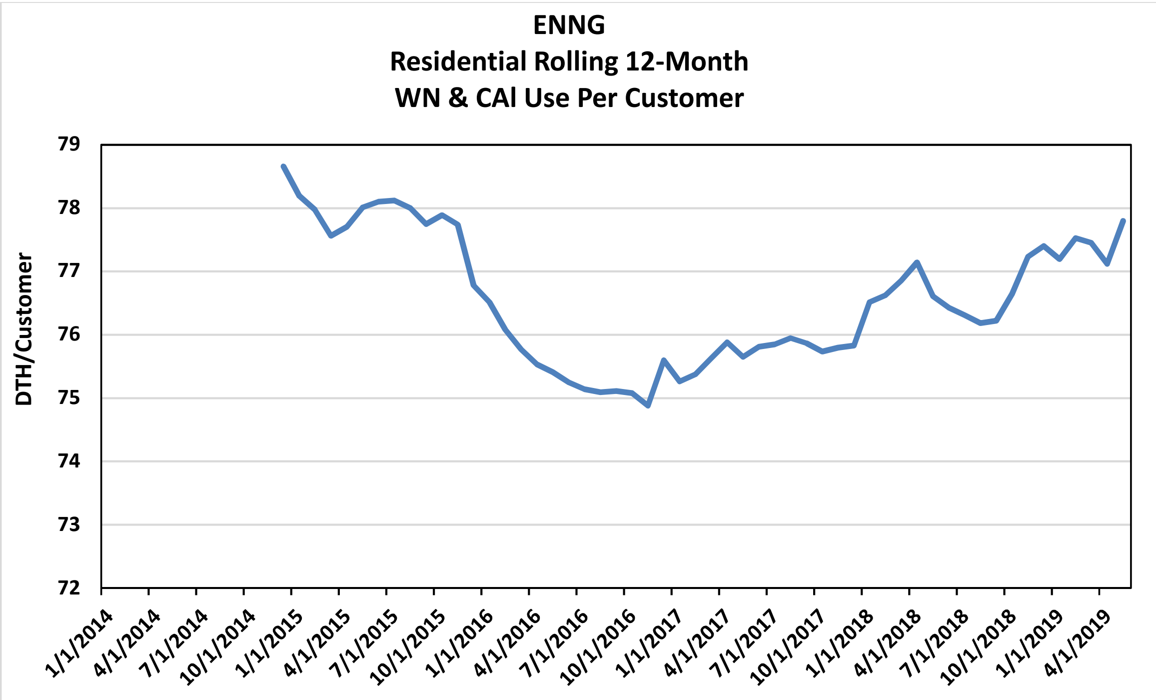
Apr-19

ENNG


ENNG
Residential Rolling 12-Month
WN & CAl Use Per Customer
DTH/Customer
79
78
77
76
75
74
73
72
1/1/2014
4/1/2014
7/1/2014
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4/1/2015
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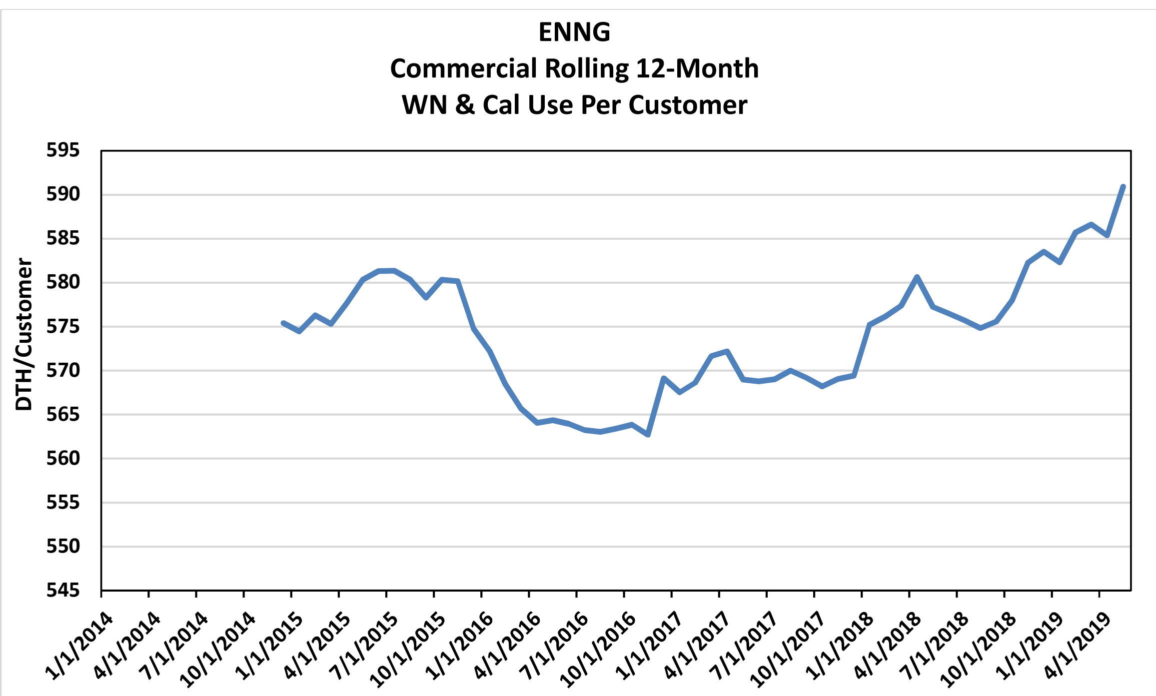
4/1/2019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Commercial Rolling 12-Month
WN & Cal Use Per Customer
DTH/Customer
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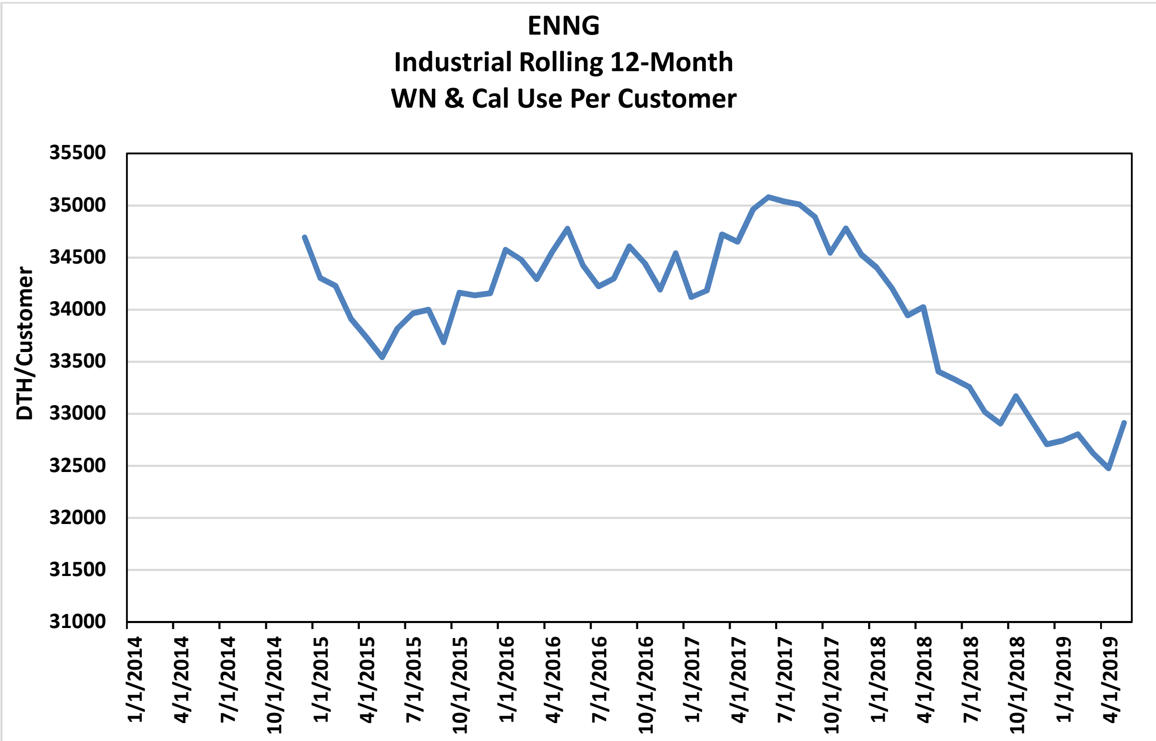
ENNG
Industrial Rolling 12-Month
WN & Cal Use Per Customer
DTH/Customer
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33500
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32500
32000
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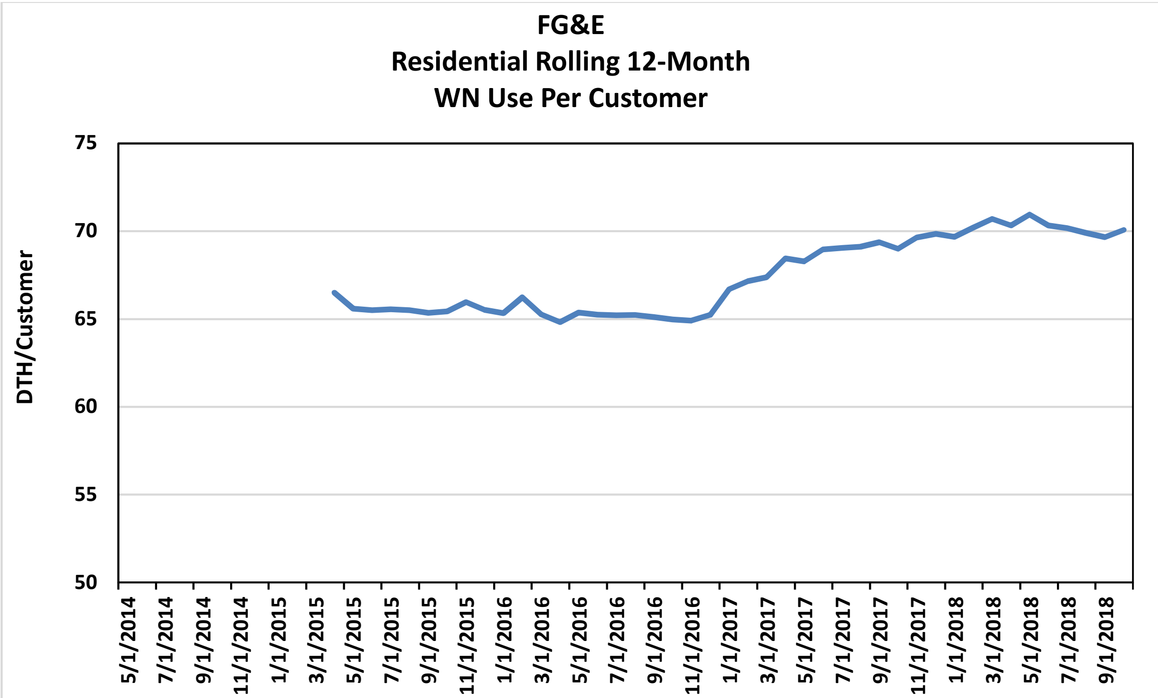
4/1/2019

FGE


FG&E
Residential Rolling 12-Month
WN Use Per Customer
DTH/Customer
75
70
65
60
55
50
5/1/2014
7/1/2014
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11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
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3/1/2017
5/1/2017
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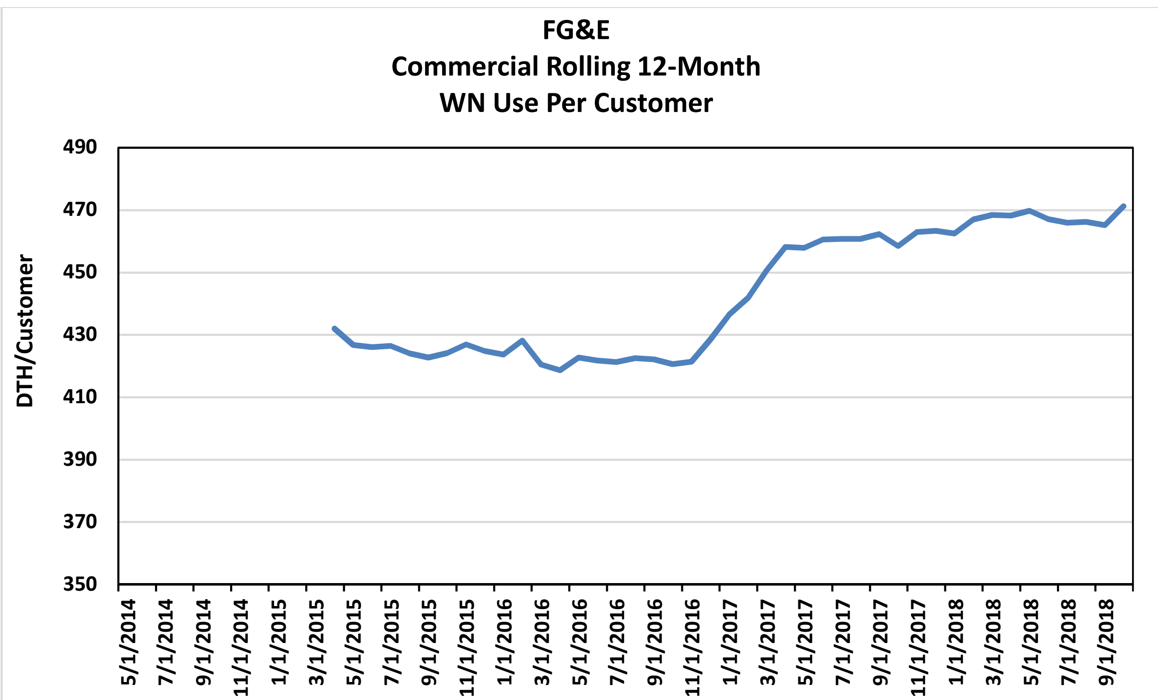
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


FG&E
Commercial Rolling 12-Month
WN Use Per Customer
DTH/Customer
490
470
450
430
410
390
370
350
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
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9/1/2016
11/1/2016
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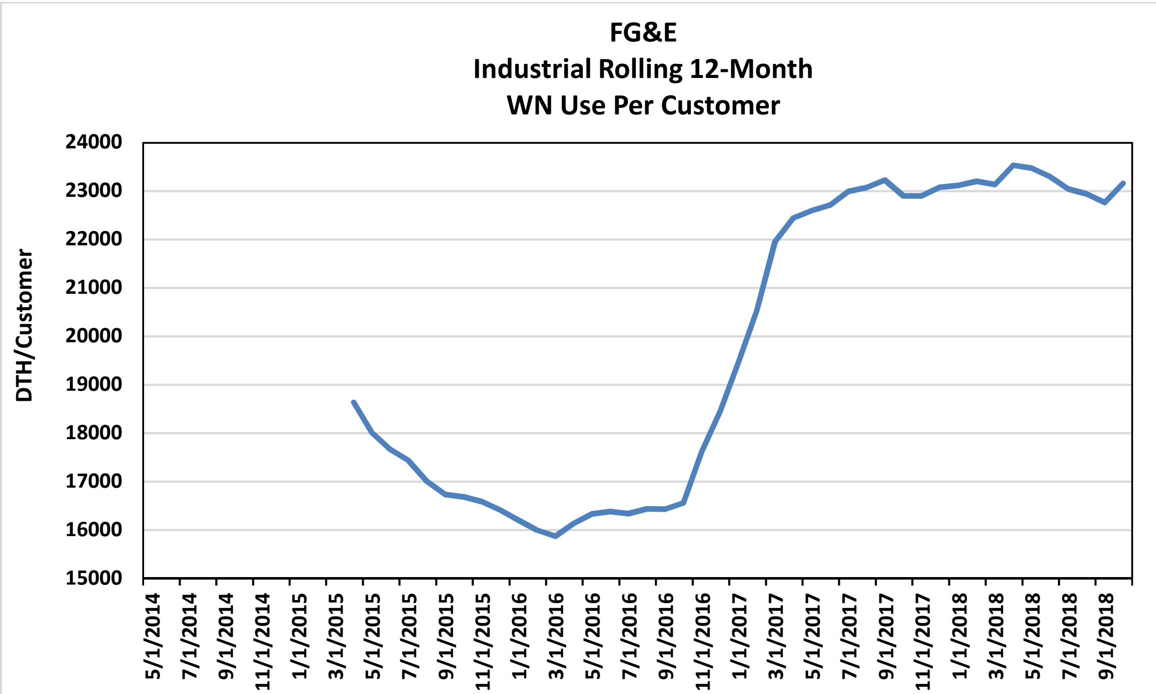
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


FG&E
Industrial Rolling 12-Month
WN Use Per Customer
DTH/Customer
24000
23000
22000
21000
20000
19000
18000
17000
16000
15000
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
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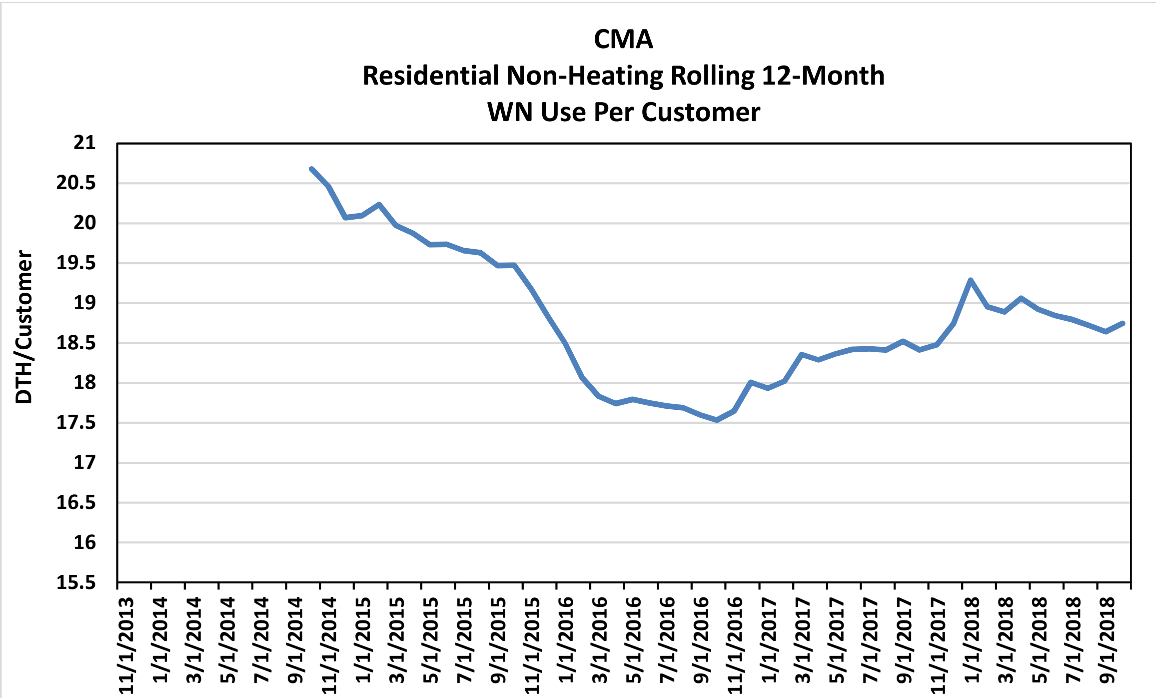
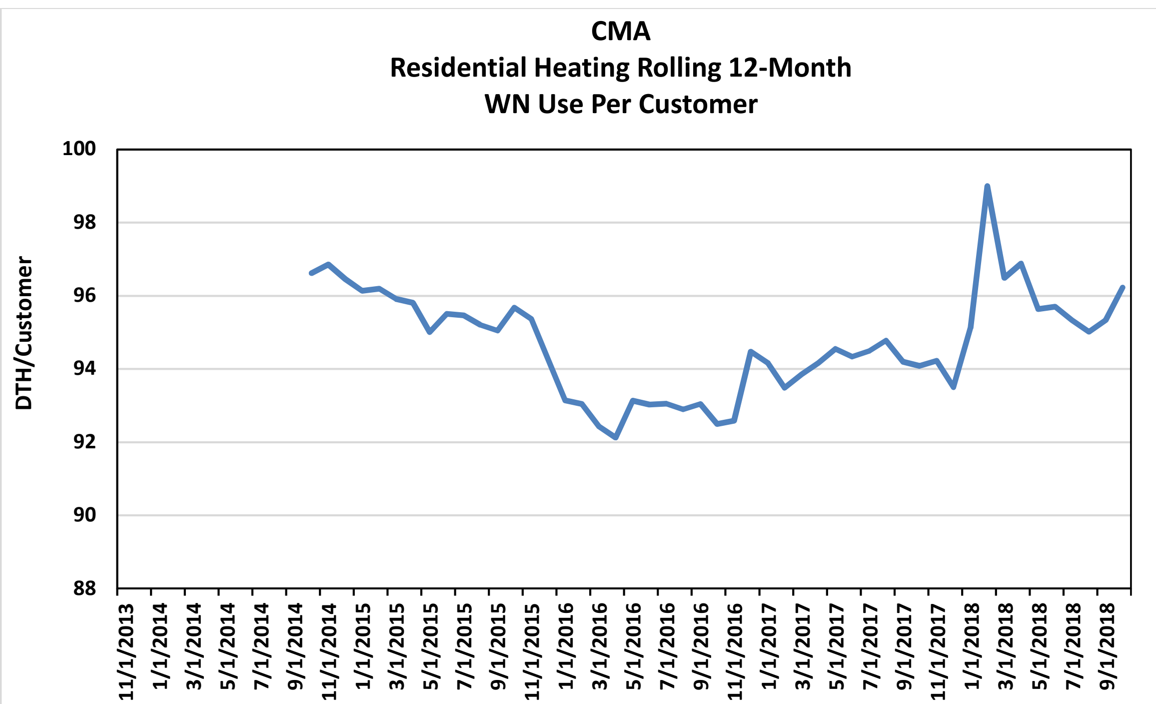
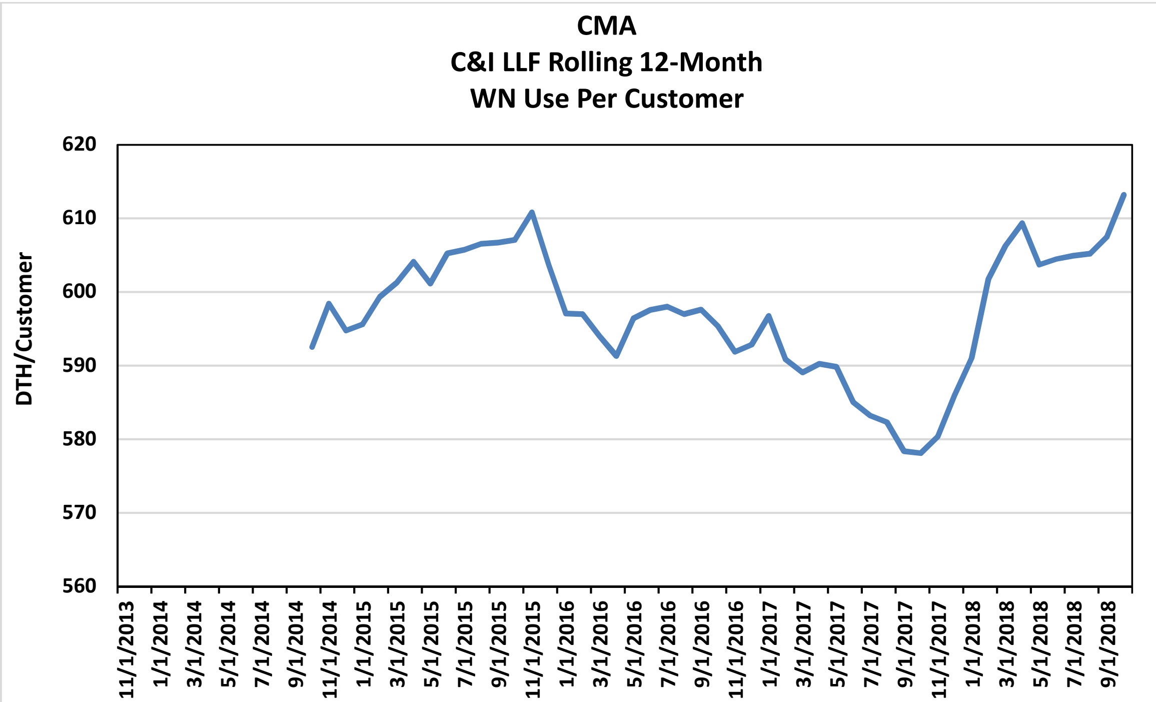
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

CMA


CMA
Residential Non-Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
21
20.5
20
19.5
19
18.5
18
17.5
17
16.5
16
15.5
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


CMA
Residential Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
100
98
96
94
92
90
88
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


CMA
C&I LLF Rolling 12-Month
WN Use Per Customer
DTH/Customer
620
610
600
590
580
570
560
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
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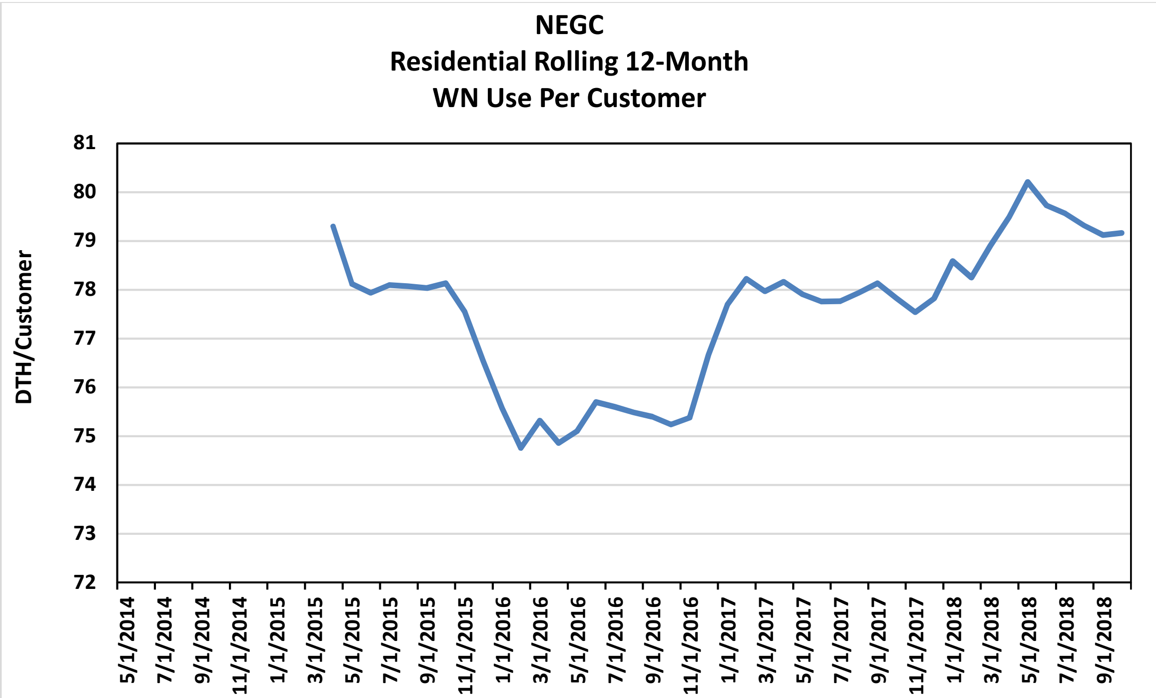
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

NEGC


NEGC
Residential Rolling 12-Month
WN Use Per Customer
DTH/Customer
81
80
79
78
77
76
75
74
73
72
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
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3/1/2017
5/1/2017
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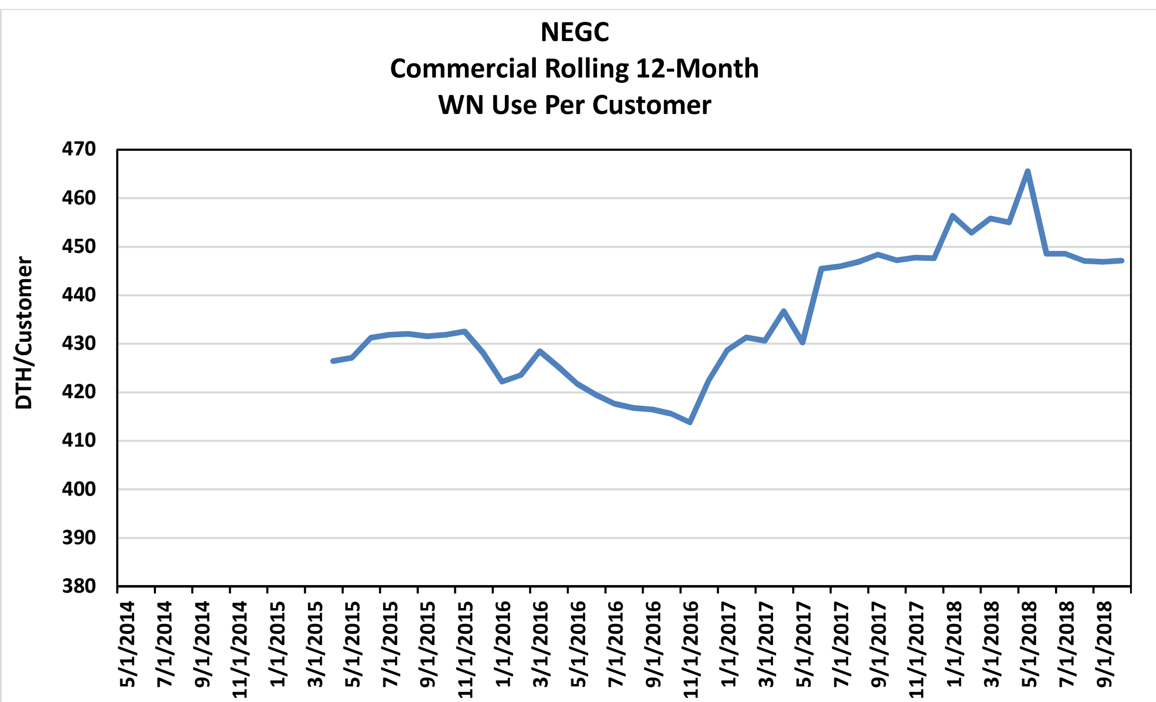
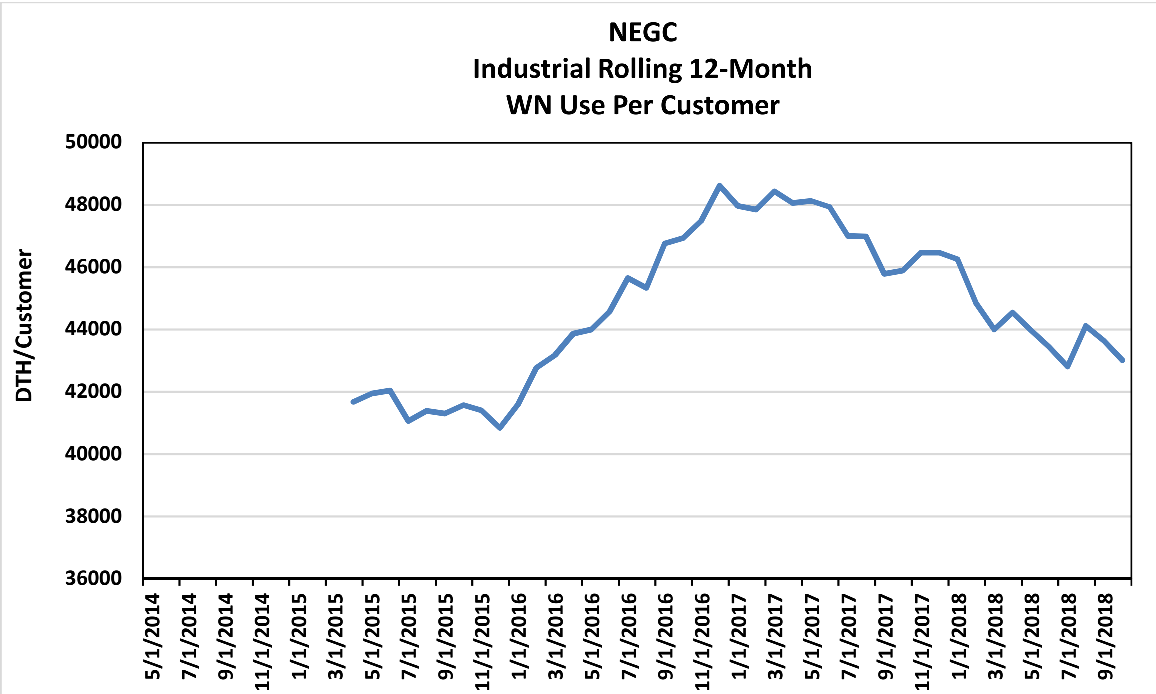
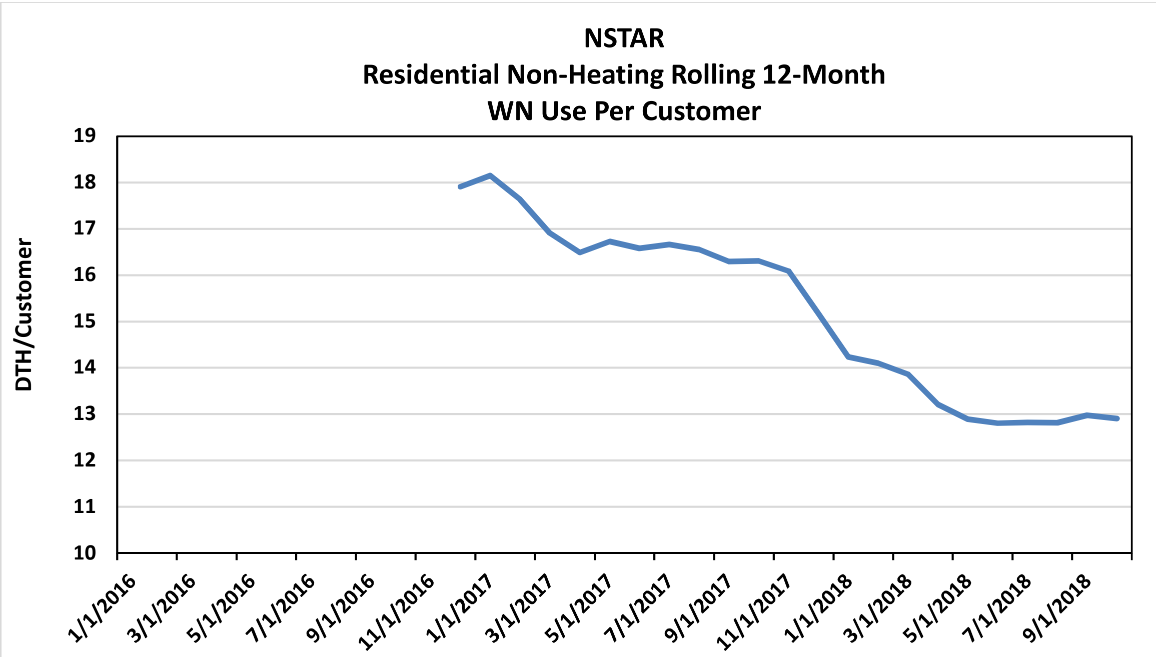
5/1/2018
7/1/2018
9/1/2018


NEGC
Commercial Rolling 12-Month
WN Use Per Customer
DTH/Customer
470
460
450
440
430
420
410
400
390
380
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NEGC
Industrial Rolling 12-Month
WN Use Per Customer
DTH/Customer
50000
48000
46000
44000
42000
40000
38000
36000
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

NSTAR


NSTAR
Residential Non-Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
19
18
17
16
15
14
13
12
11
10
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
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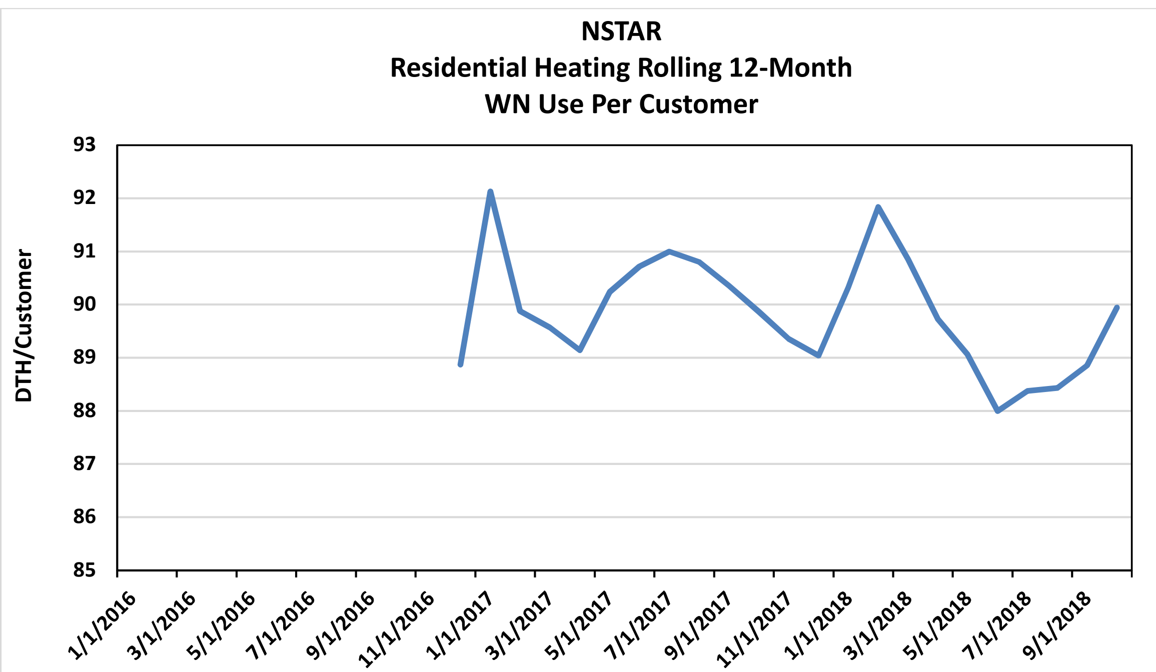
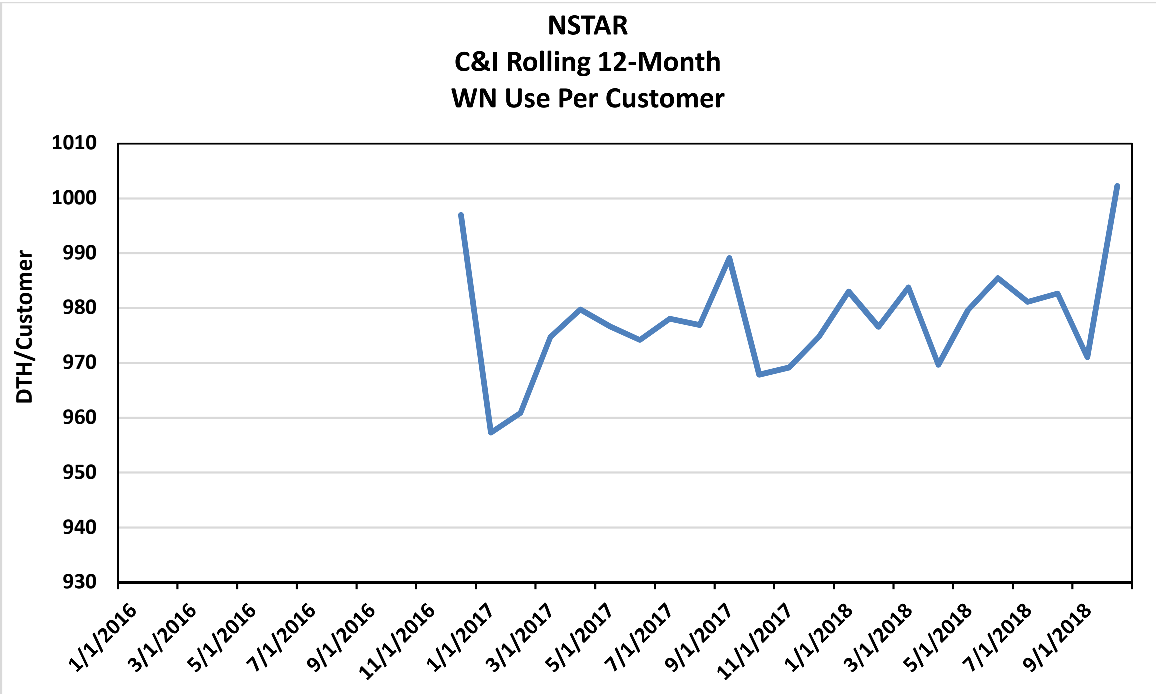
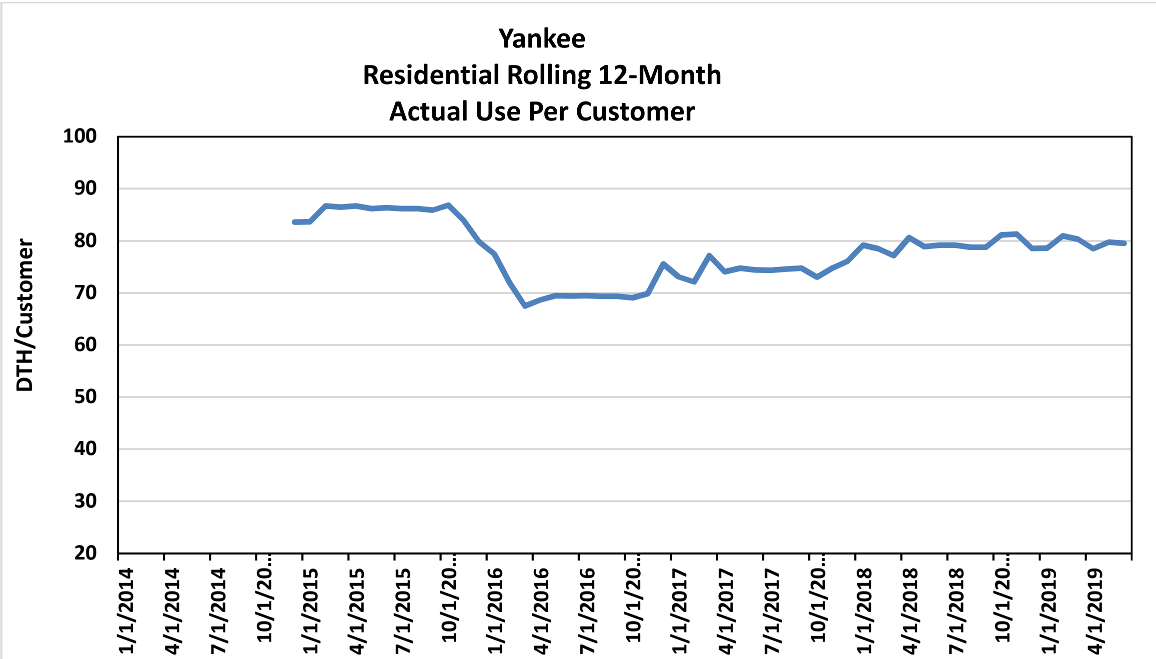
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NSTAR
Residential Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
93
92
91
90
89
88
87
86
85
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NSTAR
C&I Rolling 12-Month
WN Use Per Customer
DTH/Customer
1010
1000
990
980
970
960
950
940
930
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

YGS


Yankee
Residential Rolling 12-Month
Actual Use Per Customer
DTH/Customer
100
90
80
70
60
50
40
30
20
1/1/2014
4/1/2014
7/1/2014
10/1/20...
1/1/2015
4/1/2015
7/1/2015
10/1/20...
1/1/2016
4/1/2016
7/1/2016
10/1/20...
1/1/2017
4/1/2017
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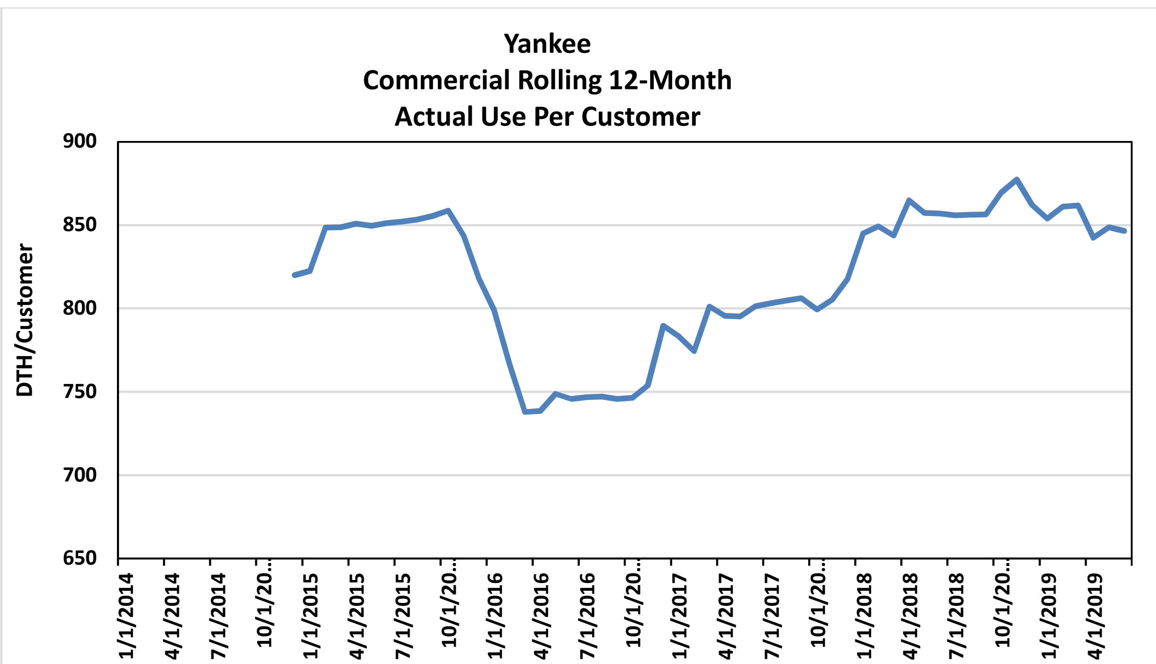
1/1/2019
4/1/2019


Yankee
Commercial Rolling 12-Month
Actual Use Per Customer
DTH/Customer
900
850
800
750
700
650
1/1/2014
4/1/2014
7/1/2014
10/1/20...
1/1/2015
4/1/2015
7/1/2015
10/1/20...
1/1/2016
4/1/2016
7/1/2016
10/1/20...
1/1/2017
4/1/2017
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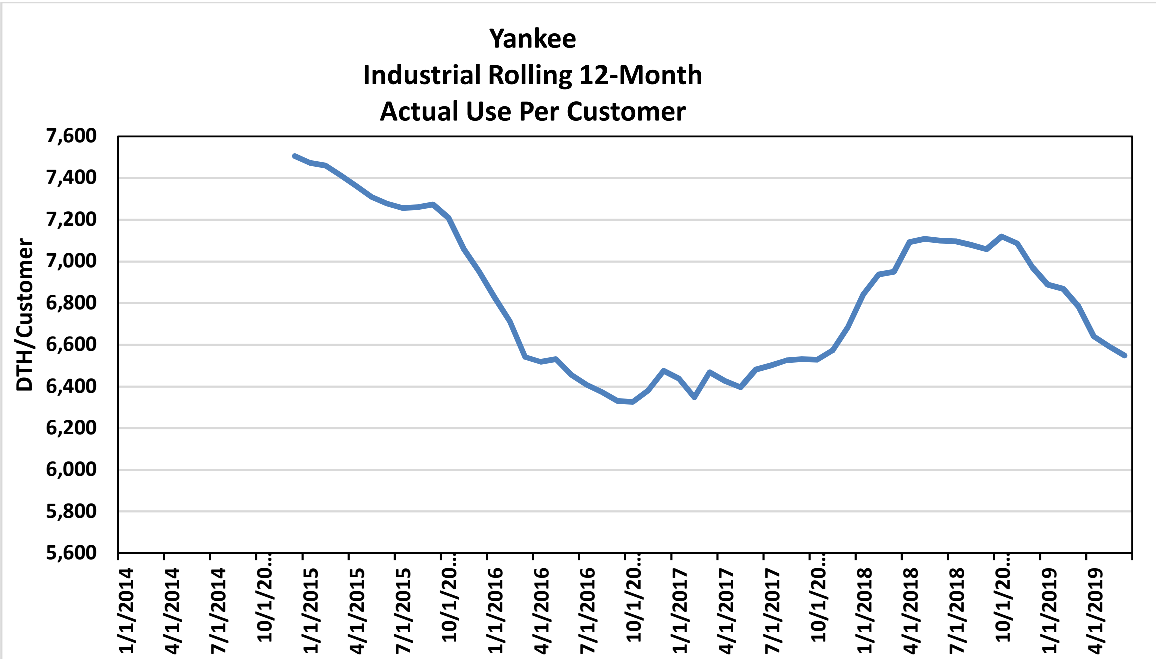
1/1/2019
4/1/2019


Yankee
Industrial Rolling 12-Month
Actual Use Per Customer
DTH/Customer
7,600
7,400
7,200
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
1/1/2014
4/1/2014
7/1/2014
10/1/20...
1/1/2015
4/1/2015
7/1/2015
10/1/20...
1/1/2016
4/1/2016
7/1/2016
10/1/20...
1/1/2017
4/1/2017
7/1/2017
10/1/20...
1/1/2018
4/1/2018
7/1/2018
10/1/20...
1/1/2019
4/1/2019

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

DG 20-105
Distribution Service Rate Case

Staff Data Requests - Set 3

Date Request Received: 12/16/20 | Date of Response: 1/4/21
Request No. Staff 3-5 | Respondent: Steven Mullen

REQUEST:

Ref. Mullen Testimony, Bates page II-198, line 12-20. Please explain the following:

a. How an increase in use per customer impacts the company under decoupling;

b. Why reclassification was needed after the last rate case, and provide any analysis the company did regarding the impact of reclassification.

RESPONSE:

a. In general, an increase in average use per customer will result in a revenue shortfall under decoupling. The decoupling mechanism transforms the actual seasonal fixed-variable customer class rate designs used for billing into an equivalent series of fixed rates—the allowed base revenues per bill ("RPC"). These transformations are done under specific circumstances at a specific point in time, which reflect the average use per customer at that point. Subsequent changes in the number of customers and their average use will be reflected in the decoupling mechanism as follows: If the average use decreases, the allowed base revenues under decoupling will exceed actual billings, and the deficiency will be recovered from customers through the Revenue Decoupling Adjustment Factor ("RDAF"); conversely, if the average use increases, the actual billings will exceed the allowed base revenues, and the excess will be returned to customers through the RDAF.

b. The "reclassification" referred to in Mr. Mullen's Testimony, Bates page II-198, lines 15–19 was the result of the initial run of the Company's Rate Review process, which was under development in 2016. The Rate Review process was not driven by the Docket DG 17-048 rate case, and its timing post-test year in early 2017 was entirely coincidental. The Rate Review process commences with a computer-generated weather-normalized historical billing comparison for each eligible customer of their present rate to one or more proposed rates based on rate class eligibility criteria. The results are then manually reviewed by customer care personnel, and if determined to be correct, each affected customer is notified and a rate change is made. The summary results of the computer-generated initial run are shown in Attachment Staff 3-5.

Row Labels	Customers	Sum of New_Amount	Sum of Cur_Amount	Difference	PctDiff
40-GC41	**489**	**$1,625,755**	**$1,477,848**	**$147,906**	**10.0%**
40-GC42	166	$1,126,603	$874,198	$252,405	28.9%
40-GC43	1	$38,336	$43,392	($5,056)	-11.7%
40-GC51	283	$291,000	$367,054	($76,053)	-20.7%
40-GC52	39	$169,814	$193,204	($23,390)	-12.1%
40-GC42	**529**	**$2,028,051**	**$3,232,280**	**($1,204,229)**	**-37.3%**
40-GC41	386	$952,523	$1,565,997	($613,474)	-39.2%
40-GC43	12	$395,895	$397,630	($1,736)	-0.4%
40-GC51	40	$62,497	$149,260	($86,763)	-58.1%
40-GC52	87	$494,259	$800,905	($306,646)	-38.3%
40-GC53	3	$81,360	$131,327	($49,967)	-38.0%
40-GC54	1	$41,518	$187,161	($145,643)	-77.8%
40-GC43	**18**	**$363,339**	**$456,199**	**($92,860)**	**-20.4%**
40-GC42	15	$248,808	$294,196	($45,387)	-15.4%
40-GC53	3	$114,531	$162,004	($47,473)	-29.3%
40-GC51	**437**	**$722,918**	**$528,731**	**$194,187**	**36.7%**
40-GC41	384	$457,086	$366,661	$90,425	24.7%
40-GC42	19	$124,205	$60,291	$63,915	106.0%
40-GC52	34	$141,627	$101,780	$39,847	39.2%
40-GC52	**97**	**$650,380**	**$560,023**	**$90,356**	**16.1%**
40-GC41	17	$39,681	$49,875	($10,194)	-20.4%
40-GC42	37	$387,181	$238,836	$148,345	62.1%
40-GC43	1	$28,061	$15,953	$12,108	75.9%
40-GC51	35	$64,335	$108,873	($44,539)	-40.9%
40-GC53	3	$67,820	$53,140	$14,680	27.6%
40-GC54	4	$63,302	$93,346	($30,044)	-32.2%
40-GC53	**10**	**$172,517**	**$189,903**	**($17,386)**	**-9.2%**
40-GC41	1	$1,274	$8,148	($6,874)	-84.4%
40-GC42	4	$59,079	$55,844	$3,236	5.8%
40-GC43	2	$66,955	$49,425	$17,530	35.5%
40-GC52	1	$12,352	$17,495	($5,142)	-29.4%
40-GC54	2	$32,856	$58,992	($26,136)	-44.3%
40-GC54	**9**	**$538,814**	**$254,359**	**$284,455**	**111.8%**
40-GC41	1	$1,911	$8,059	($6,148)	-76.3%
40-GC43	1	$45,249	$17,216	$28,033	162.8%
40-GC52	1	$4,298	$8,508	($4,210)	-49.5%
40-GC53	6	$487,355	$220,576	$266,779	120.9%
40-GR1	**149**	**$84,619**	**$54,898**	**$29,721**	**54.1%**
40-GR3	149	$84,619	$54,898	$29,721	54.1%
40-GR3	**2,375**	**$647,255**	**$975,686**	**($328,431)**	**-33.7%**
40-GR1	2,375	$647,255	$975,686	($328,431)	-33.7%
Grand Total	**4,113**	**$6,833,648**	**$7,729,928**	**($896,281)**	**-11.6%**

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

DG 20-105
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 3

Date Request Received: 2/8/21	Date of Response: 2/24/21
Request No. Staff TS 3-9	Respondent: Heather Tebbetts

REQUEST:

Please provide a copy of the most recent 5-year capital spending plan.

RESPONSE:

Please see Attachment Staff TS 3-9.xlsx for the Company's most recent capital spending plan.

As shown in the attachment, the capital spending plan includes a variety of investments, many of which are standard types of projects and programs included in the annual capital budget, such as replacement of leak-prone mains and services, new services, meter purchases, and city/state construction. Also included in the annual capital budget are the gas system planning and reliability investments and the gas system supply investments that were discussed during the early February technical sessions. Also, consistent with the response to OCA 3-10, the Company has included its planned investment in SAP (referred to as Customer First), which is a critical project to replace the current Customer Information System, accounting system, and other various operations and work planning systems. As noted in the response to OCA 3-10, the Company is in the process of finalizing its analysis of the overall costs and benefits of the Customer First project and will have that analysis available by the end of the first quarter of 2021.

Liberty Utilities (EnergyNorth Natural Gas) d/b/a Liberty
Attachment Staff TS 3-9 5-Year Capital Spending Plan

Project Description	Priority	FY2021	FY2022	FY2023	FY2024	FY2025
Reserve for Unidenfitied Mandated Projects	2. Mandated	200,000	206,000	206,000	212,180	212,180
Meter Protection Program	2. Mandated	500,000	300,000	300,000	300,000	300,000
Cathodic Protection Program	2. Mandated	500,000	620,000	849,750	849,750	849,750
Replacement Services Random (Non Leaks)	2. Mandated	450,000	550,000	592,250	592,250	592,250
Replacement Services Random (Due to Leaks)	2. Mandated	550,000	750,000	750,000	750,000	750,000
Corrosion & Miscellaneous Fitting	2. Mandated	250,000	108,150	111,395	111,395	111,395
Valve Installation/Replacement	2. Mandated	60,000	75,000	75,000	75,000	75,000
Leak Repairs	2. Mandated	1,750,000	1,262,745	1,300,628	1,339,647	1,379,836
Main Replacement LPP	4. Regulatory Programs	8,601,098	17,380,841	19,420,363	21,773,837	24,362,658
Main Replacement LPP-Restoration	4. Regulatory Programs	4,069,903	4,014,376	4,114,376	4,114,376	4,114,376
Main Replacement Fitting LPP	5. Discretionary	740,501	1,330,636	1,370,555	1,411,672	1,454,022
K Meter Replacement Program	5. Discretionary	350,000	3,090,000	3,182,700	3,278,181	3,491,328
Aldyl-A Replacement Program	5. Discretionary	200,000	966,543	1,063,197	1,169,517	1,286,468
Main Replacement Reactive	5. Discretionary	600,000	653,679	719,047	790,952	790,952
Dispatch and Control Center	5. Discretionary	10,000	10,000	10,300	10,300	10,300
Purchase Misc Capital Equipment & Tools	1. Safety	200,000	280,000	280,000	280,000	280,000
Regulator removal Hi line LOU	5. Discretionary	50,000	250,000	250,000	250,000	250,000
SCADA Capital Improvements	5. Discretionary	80,000	80,000	82,400	82,400	82,400
Upgrade Synergi Software	5. Discretionary	65,000	65,000	65,000	65,000	65,000
Inactive Service Program	2. Mandated	75,000	75,000	75,000	75,000	75,000
Main Replacement City/State Construction	2. Mandated	4,654,819	2,374,131	2,611,544	2,872,699	3,159,969
Nashua Paving	5. Discretionary	760,000	-	-	-	-
Service Replacement Fitting City/State Construction	2. Mandated	303,000	153,378	157,980	162,719	167,601
LNG/LPG Capital Improvements	2. Mandated	100,000	103,000	106,090	106,090	106,090
Reserve for Unidentified Growth ENG	3. Growth	1,500,000	1,342,250	1,542,250	1,542,250	1,542,250
Gas System Control & Regulation (ENG)	5. Discretionary	425,000	-	-	-	-
Pre-Code Stee Pipe Protection Program/Replacement	2. Mandated	200,000	500,000	500,000	500,000	500,000
IT - Software, Equipment & Infrastructure	5. Discretionary	50,000	50,000	50,000	50,000	50,000
Gas System Planning & Reliability	5. Discretionary	2,900,000	4,500,000	13,900,000	6,380,000	7,400,000
IT Systems Allocations - Corporate	5. Discretionary	450,000	500,000	500,000	500,000	500,000
Dresser Coupling Replacement Program	2. Mandated	500,000	487,245	501,862	516,918	532,425
Growth New Main	3. Growth	4,534,000	4,631,100	4,731,100	4,831,100	4,982,100
New Reinforcement Main for Growth ENG	3. Growth	-	800,000	1,000,000	1,000,000	1,000,000
Growth Fitting	3. Growth	1,754,528	1,304,528	1,304,528	1,504,528	1,504,528
New Service Residential	3. Growth	3,252,817	3,038,850	3,038,850	3,138,850	3,138,850
New Service Comm/Industrial	3. Growth	1,086,333	1,067,723	1,067,723	1,067,723	1,067,723
Marketing & Sales	3. Growth	-	150,000	150,000	150,000	150,000
Transportation Fleet and Equipment Purchases	5. Discretionary	2,013,000	800,000	200,000	866,000	1,500,000
Meter Work Project (Meter Purchases)	2. Mandated	1,150,000	1,020,545	1,220,545	1,220,545	1,220,545
EN Facilities Capital Improvements	5. Discretionary	600,000	600,000	600,000	600,000	600,000
Install Security Equipment - EN Facilities	2. Mandated	-	103,000	26,523	26,523	20,403
Facility Improvements & Additions - Various	2. Mandated	-	-	106,090	406,090	400,090
Install Solar Panels - EN Buildings	5. Discretionary	-	-	300,000	-	-
Repave Parking Lot - Manchester	5. Discretionary	-	800,000	-	-	-
AMI/AMR	5. Discretionary	-	-	-	-	4,031,440
2' Jamesbury replacement program	1. Safety	-	60,000	60,000	60,000	60,000
RTU Replacement Program	5. Discretionary	60,000	60,000	60,000	60,000	60,000
Customer First/SAP	5. Discretionary	-	35,904,324	-	-	-
Finance Unalloc Burden	5. Discretionary	500,000	703,428	703,531	703,351	703,132
Gas Supply System Enhancements	5. Discretionary	-	17,800,000	5,000,000	27,700,000	-
GPS Mapping Equipment	5. Discretionary	50,000	-	-	-	-
Service Mapping Project	5. Discretionary	300,000	-	-	-	-
Flir Cameras - Security -Manchester (Nashua)	5. Discretionary	900,000	-	-	-	-
SAP-Ariba EN Portion Procure to Pay Software	5. Discretionary	215,000	-	-	-	-
FLIR-Tilton	5. Discretionary	440,000	-	-	-	-
	Total	47,999,999	110,921,473	74,256,576	93,496,840	74,930,060

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests – Set 7

Date Request Received: 9/21/17 | Date of Response: 10/5/17
Request No. Staff 7-9 | Respondent: Paul Normand

REQUEST:

Reference testimony of Paul M. Normand, attachment PMN-2, Bates page 445: Given that average life, net salvage, and similar curve are being used for this account in the current and most recent depreciation study:

a. In your expert opinion, what are the possible reasons for the very large swings in reserve variances?

b. Does the Company's proposed level reserve variance amortization address the account level variances?

c. What are your recommendations to minimize such swings in reserve variances at the account level?

RESPONSE:

a. The large swing in the reserve variance is primarily from two accounts: Mains (367.00) and Services (380.00) since the Company's last study. The large deviation is a direct result of the very large plant dollar increases for these accounts (Mains $98M, Services $66M) driven primarily by the mandated replacement program (CIBS) which is expected to continue for some period of time. As a result, we expect that this behavior will continue to be exhibited in a similar fashion as has been experienced but at a lower level since the recent amortization from the last study will be terminated.

b. The Company's proposed amortization factors consider many additional aspects that go well beyond a typical depreciation study to consider. The depreciation study itself continues to recommend a two cycle amortization of the variances without any consideration for the impact to the reserve variances from the last ten years.

c. As I mentioned in response part a. above, the Company's continued replacement program is impacting primarily two accounts which will continue to require large plant investment well into the foreseeable future. The current results and variances will continue to be exhibited, but a reduced level for the immediate future with the following options capable of minimizing future variances:

1) Change the current depreciation model from a Whole Life (WL) to a Remaining Life (RL) model which is well recognized in the industry and regulators alike. This calculation incorporates the existing reserve levels for each account in deriving the accrual rate for each account. In this manner, the RL approach is self-correcting over time.
2) If maintaining the WL approach is required, then consider establishing a collar or a threshold band width for the variance such that no amortization would occur unless the variance is in excess of 5 or 10% of the theoretical level.
3) More frequent studies for selected accounts to evaluate the variance levels. This would control the costs somewhat while providing additional information to regulators with respect to the larger and faster growing plant accounts, especially where mandated requirements are in effect.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 20-141

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

Winter 2020/2021 Cost of Gas and Summer 2021 Cost of Gas Filing

Order Approving Cost of Gas Rates and Other Charges

O R D E R N O. 26,419

October 30, 2020

APPEARANCES: Michael J. Sheehan, Esq., for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities; the Office of the Consumer Advocate, by Christa Shute, Esq., on behalf of residential ratepayers; and Mary E. Schwarzer, Esq., for the Staff of the Public Utilities Commission.

This order approves a proposal by Liberty EnergyNorth for winter 2020-2021 and summer 2021 cost of gas (COG) rates. The initial residential COG rate for the winter period (November 1, 2020, through April 30, 2021) will be \$0.5571 per therm, and the fixed-price option will be \$0.5771 per therm. The local distribution adjustment clause rate will be \$0.0589 per therm from November 1, 2020, through October 31, 2021. A typical residential heating customer will pay approximately \$883 for the 2020-2021 winter period, compared to \$792 for last winter.

The initial residential cost of gas rate for the summer period (May 1, 2021, through October 31, 2021) will be \$0.3148 per therm. A typical residential heating customer will pay approximately \$229 for the 2021 summer period compared to \$227 for last summer.

I. PROCEDURAL HISTORY

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty EnergyNorth[1] or the Company) is a public utility that distributes natural gas to approximately 97,000 customers in

[1] Liberty EnergyNorth is comprised of multiple divisions with a single COG for all divisions other than the Keene Division. That cost of gas is referred to as the EnergyNorth COG. This order refers to the Company as "Liberty EnergyNorth" to

southern and central New Hampshire and in the City of Berlin. On September 1, 2020, Liberty EnergyNorth submitted a tariff filing for the winter 2020-2021 and summer 2021 periods that proposed adjustments to COG rates. The filing, which included pre-filed direct testimony and supporting schedules, proposes changes to COG rates for firm sales customers, fixed winter COG rates under the fixed-price option (FPO), firm transportation COG rates, and the local distribution adjustment clause (LDAC). It also included a revenue decoupling adjustment factor (RDAF) as part of the LDAC, as decoupling was implemented in 2018 and first referenced in COG orders last year. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order 26,122 at 43-46, 53-55 (April 27, 2018) (approving decoupling); Order No. 26,187 at 11 (November 2, 2018) (approving illustrative decoupling tariff); Order No. 26,306 (October 31, 2019) (Liberty EnergyNorth Winter 2019-2020 COG).

The Office of the Consumer Advocate (OCA) notified the Commission of its participation on behalf of residential ratepayers on September 8, 2020. There were no petitions for intervention filed in the docket, and no persons appeared at the hearing to provide public comment on the proposed rates.

The Order of Notice was issued on September 9, 2020. Commission Staff (Staff) conducted discovery and held a technical session with Liberty EnergyNorth and the OCA on September 23.

The Company made a number of revised filings. On October 16, 2020, the Company filed revised pre-filed testimony of David B. Simek and Catherine A. McNamara, with revised tariff pages and schedules. In particular, at the request of Staff, this filing recalculated the RDAF by customer class, as required by tariff. On October 19, 2020, at the request of Staff, the Company filed redlined versions of all changes made in the testimony, tariff pages, and schedules.[2] On October 22, 2020, at the

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distinguish among divisions for purposes of COG rate-setting. The Liberty-Keene Winter 2020-2021 COG docket, Docket DG 20-152, is pending at this time.

[2] On October 21, consistent with the Commission's *Remote Hearing Guidelines*, Staff marked the Company's redlined filing Exhibit 5 for identification. At hearing, Exhibit 5 was not admitted as a full exhibit and was replaced with Exhibit 6.

request of Staff, the Company corrected errors in the redlined filing and provided an updated document. Staff marked the updated redlined documents as Exhibit 6, and filed the exhibit.

The petition and subsequent docket entries, other than any information for which confidential treatment is requested of or granted by the Commission, are posted on the Commission's website at https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-141.html.

II. COST OF GAS ADJUSTMENT MECHANISM

The COG adjustment mechanism was implemented in 1974 during a time of rapidly changing prices as a way to pass on to consumers increases and decreases in energy supply costs quickly, without having to go through extended proceedings to change delivery rates. Supply costs make up approximately half of a residential heating customer's annual bill and include commodity prices (the cost of gas), the cost to transport the gas over the pipelines, and storage costs.

Liberty EnergyNorth has little control over the price of natural gas, which is an unregulated commodity. Similarly, the Company has little price control over pipeline transportation rates, which are set by the Federal Energy Regulatory Commission. The COG adjustment mechanism allows the Company to pass fuel supply costs on to its customers directly and efficiently without mark-up or profit. COG rates are initially set using projected costs and sales for the upcoming winter and summer periods. Through the COG adjustment mechanism, the Company may adjust its COG rates monthly to take into account changes in the natural gas market based on actual costs to date and projected costs for the remainder of the period. To the extent that adjustments are based on projected costs, they are subject to reconciliation periodically, after actual costs are known.

In the COG docket, the Commission also sets the LDAC rates that allow for recovery of expenses the Commission has approved in prior dockets through a per therm charge to be determined and implemented in the COG proceeding. The LDAC is a component of the Company's proposed COG rates in both the Liberty EnergyNorth and the Liberty Keene Division dockets. Order 26,122 at

37-41. LDAC expenses include costs associated with an environmental surcharge for manufactured gas plant remediation, Liberty Utilities' energy efficiency and low-income programs, and the RDAF.

III. POSITIONS OF THE PARTIES AND STAFF

A. Liberty EnergyNorth

In its initial filing of September 1, 2020, Liberty EnergyNorth proposed several rates for approval, including winter and summer COG rates for various rate classes, annual LDAC rates for various rate classes, a fixed price option COG rate for residential customers, and a firm transportation COG rate. *See* Exhs. 1-3; Exhibit 1 Bates 049 (transportation rate).

In the Company's revised filings, Liberty EnergyNorth made several changes primarily affecting the LDAC (including changes to the RDAF to calculate by separate rate class), and resulting in proposed amendments to the tariff and schedules. *See* Exhs. 3 and 6. The LDAC also includes costs associated with Liberty's participation in the Gas Assistance Program, formerly known as the Residential Low Income Assistance Program, as well as the costs associated with administering that program.[3]

Liberty EnergyNorth's proposed winter COG per therm rates for the various rate classes are $0.5571 for residential; $0.5552 for commercial and industrial (C&I) high winter use; and $0.5660 for C&I low winter use. The Company's proposed summer COG per therm rates are $0.3148 for residential, $0.3109 for C&I high winter use, and $0.3199 for C&I low winter use. *See* Exhs. 3at 085R-088R (winter rates and bill impacts) and 229R-232R (summer rates and bill impacts). In its revised filings, the Company proposed an LDAC rate of 0.0589 per therm for residential customers from November 1, 2020, through October 31, 2021, and $0.0555 per therm for C&I customers for the same period. Exhs. 3 and 6 at 052R.

[3] *See* Order No. 26,397 (August 27, 2020, Docket No. 20-013) (modifying the Residential Low Income Assistance Program for natural gas and renaming it the "Gas Assistance Program").

The following tables include the expected total bill impact based on the prior winter's and summer's average use for each customer class.

Winter 2020/2021 Projected Bill Impacts

Class	2019-2020 (Actual)	2020-2021 (Projected)	Percent Change
R-3 Residential Heating	$ 792	$ 883	11%
G-42 C&I High Winter Use	$ 13,718	$ 15,427	12%
G-52 C&I Low Winter Use	$ 9,220	$ 10,387	13%

Summer 2021 Projected Bill Impacts

Class	2020 (Actual)	2021 (Projected)	Percent Change
R-3 Residential Heating	$ 227	$ 229	1%
G-42 C&I High Winter Use	$ 3,234	$ 3231	0%
G-52 C&I Low Winter Use	$ 4,966	$ 4,638	-7%

The initial residential cost of gas rate for the winter period (November 1, 2020, through April 30, 2021) will be $0.5571 per therm, and the fixed-price option will be $0.5771 per therm. The (LDAC) rate will be $0.0589 per therm from November 1, 2020, through October 31, 2021, compared to $.0310 for the prior year. The initial residential cost of gas rate for the summer period (May 1, 2021 through October 31, 2021) will be $0.3148 per therm.

The Company also proposed: (1) a supplier balancing charge of $0.12 per MMBtu of daily imbalances; (2) a transportation peaking service demand charge of $17.32 per MMBtu of peak maximum daily quantity per month; (3) a gas allowance factor of 1.6 percent; (4) transportation capacity allocators; (5) short-term debt limits of $14,742,890 for fuel financing, and $105,567,204 for non-fuel financing for the November 1, 2020, through October 31, 2021, period. *See* Exhibit 1, Bates 049, 053 and 196.

B. Staff

Staff identified inaccuracies in Liberty EnergyNorth's initial filing that resulted in recalculated RDAFs by customer class, and resulting changes to the proposed tariff and schedules. Exh. 6. Proposed price increases, as compared to last year's COG proposed rates are primarily due to the change in NYMEX price and prior period over/under collections.

At hearing, Staff supported approval of the proposed, revised 2020-2021 COG and LDAC rates as filed on September 1, 2020, and updated by Liberty EnergyNorth on October 16 and October 22. *See* Exhibits 1-3, 6. Staff expressed appreciation for the Company's response to Staff concerns, and a preference for the Company filing redlined revised documents as exhibits itself in future COG dockets.

C. OCA

The OCA stated that the proposed rate changes reflected in the Company's September 1 filing, as revised on October 16 and October 22, are just and reasonable, and recommended that those changes be approved.

IV. COMMISSION ANALYSIS

The Commission has broad statutory authority to set rates in addition to "powers inherent within its broad grant" of express authority. *See Appeal of Verizon New England, Inc.*, 153 N.H. 50, 64-65 (2005) (citations omitted). The Commission applies the "just and reasonable" ratemaking standard of RSA 374:2 and RSA 378:7 when setting COG rates.

This is the second Liberty EnergyNorth COG proceeding in which decoupling has been incorporated into ratemaking. Decoupling was first implemented in 2018 and was designed to sever the link between sales and revenues to remove the Company's disincentive to promote energy conservation that is inherent in traditional ratemaking. This is accomplished through the revenue decoupling adjustment factor (RDAF), which, as stated above, is part of the LDAC.

We approve the proposed winter 2020-2021 and summer 2021 COG rates, as revised in the Company's October 16 filing and October 22 submission, as just and reasonable. *See* Exhibits 2, 3, 6. We also approve the Company's proposed LDAC rate, including but not limited to the RDAF, as revised in the October 16 filing and October 22 submission, as just and reasonable. *See id*. Because actual costs and revenues are reconciled every year, any adjustments needed as a result of further inquiry into the matters addressed in this order, including final audits and actual costs, can be made in Liberty EnergyNorth's COG filing for 2021-2022.

Pursuant to *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 24,963 (April 30, 2009), the Company may adjust the COG rates based on the projected over- or under-collection for the period, the adjusted rate to be effective the first day of the month and not to exceed, cumulatively, a maximum rate of 25 percent above the approved rate, with no limitation on reductions to the COG rates. *See also Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities,* Order No. 25,958 (October 26, 2016). By approving the rates in the initial filing, as corrected in the Company's October 16 and October 22 filings, the 25 percent upward limit has an appropriate starting point at the beginning of the 2020-2021 winter period.

We note that the use of the LDAC is similar among natural gas utilities. In Liberty EnergyNorth's Tariff No. 10, LDAC is defined on page 32 as the local distribution adjustment clause:

> The purpose of the Local Distribution Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), Revenue Decoupling Adjustment Factor ("RDAF"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), rate case expenses ("RCE"), Residential Low Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time. The purpose of the Normal Weather Adjustment ("NWA") is to establish procedures that allow the Company, subject to the jurisdiction of NHPUC, to calculate and apply, for each customer on a monthly basis, the Normal Weather Factor ("NWF").

We direct Liberty EnergyNorth to modify its tariff so that LDAC is an abbreviation for local delivery adjustment charge to make the acronym consistent among gas utilities. We also direct Liberty EnergyNorth to substitute the newly adopted terminology Gas Assistance Program (GAP) for the Residential Low Income Assistance Program (RLIAP).

Based upon the foregoing, it is hereby

ORDERED, that Liberty EnergyNorth's 2020-2021 winter period COG per therm rates effective for service rendered on or after November 1, 2020, and Liberty EnergyNorth's 2021 summer period COG per therm rates effective May 1, 2021, are approved as set forth in this order, as follows:

Customer Class	2020/2021 Winter COG	2020/2021 Winter Maximum COG	2020/2021 Winter FPO	2021 Summer COG	2021 Summer Maximum COG
Residential	$0.5571	$0.6964	$0.5771	$0.3148	$0.3935
C&I High Winter Use	$0.5552	$0.6941	N/A	$0.3109	$0.3886
C&I Low Winter Use	$0.5660	$0.7075	N/A	$0.3199	$0.3999

and it is

FURTHER ORDERED, that Liberty EnergyNorth may, without further Commission action, adjust the COG rates based on the projected over- or under-collection for the period, the adjusted rate to be effective the first day of the month and not to exceed, cumulatively, a maximum rate of 25 percent above the approved rate (said maximum rates identified in the table above) with no limitation on reductions to the COG rates; and it is

FURTHER ORDERED, that Liberty EnergyNorth shall provide the Commission with its monthly calculation of the projected over- or under-collection, along with the resulting revised COG rates for the subsequent month, not less than five business days prior to the first day of the subsequent month. Liberty EnergyNorth shall include revised Calculation of the Firm Sales Cost of Gas Rate tariff pages and revised rate schedules under separate cover letter if Liberty EnergyNorth elects to adjust COG rates, with revised tariff pages to be filed as required by N.H. Admin. Rules Puc 1603; and it is

FURTHER ORDERED, that the over- or under-collection shall accrue interest at the prime rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates, the rate to be adjusted monthly; and it is

FURTHER ORDERED, that Liberty EnergyNorth's proposed LDAC per therm rates for the period November 1, 2020, through October 31, 2021, effective for service rendered on or after November 1, 2020, are $0.0589 and $0.0555 for residential and C&I customers, respectively; and it is

FURTHER ORDERED, that Liberty EnergyNorth's proposed firm transportation winter COG rate of $0.0001 per therm for the period November 1, 2020, through April 30, 2021, is approved; and it is

FURTHER ORDERED, that Liberty EnergyNorth's proposed supplier balancing charge of $0.12 per MMBtu of daily imbalance volumes is approved; and it is

FURTHER ORDERED, that Liberty EnergyNorth's proposed transportation peaking service demand charge of $17.32 per MMBtu of peak maximum daily quantity per month is approved; and it is

FURTHER ORDERED, that Liberty EnergyNorth's company gas allowance factor of 1.6 percent is approved; and it is

FURTHER ORDERED, that Liberty EnergyNorth's proposed transportation capacity allocators as filed in the *Proposed Third Revised Page 148*, *Superseding Second Revised Page 148*, are approved; and it is

FURTHER OR DERED, that Liberty EnergyNorth's proposed short-term debt limits of $14,742,890 for fuel financing and $105,567,204 for non-fuel financing for the period November 1, 2020, through October 31, 2021, are approved; and it is

FURTHER ORDERED, that Liberty EnergyNorth shall modify the LDAC definition as discussed above; and it is

FURTHER ORDERED, that Liberty EnergyNorth shall promptly file properly annotated tariff pages in compliance with this order no later than 15 days from the issuance date of this order, as required by N.H. Admin. Rules Puc 1603; and it is

FURTHER ORDERED, that before the next cost of gas proceeding, Liberty EnergyNorth shall submit its customer notice of proposed rate change for the 2021-2022 period to the Director of the Consumer Services and External Affairs Division, prior to delivery to its customers.

By order of the Public Utilities Commission of New Hampshire this thirtieth day of October, 2020.

Dianne Martin
Chairwoman

Kathryn M. Bailey
Commissioner

Attested by:

Debra A. Howland
Executive Director

Service List - Docket Related

Docket#: 20-141

Printed: 10/30/2020

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STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

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

Request for Change in Rates

Docket No. DG 20-105

SETTLEMENT AGREEMENT ON PERMANENT RATES

This Settlement Agreement on Permanent Rates ("Settlement Agreement") is entered into this 29th day of June, 2021, by and among Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty" or the "Company"), the Staff of the Public Utilities Commission participating in this proceeding ("Staff"), and the Office of the Consumer Advocate ("OCA") (together, "Settling Parties"). This Settlement Agreement resolves all issues among the Settling Parties regarding the Company's request to establish permanent rates in Docket No. DG 20-105, with the exception of Liberty's request to recover costs incurred to investigate, evaluate, and assess the development of the Granite Bridge Liquefied Natural Gas tank and related gas pipeline ("Granite Bridge Project").

SECTION 1. INTRODUCTION AND PROCEDURAL HISTORY

1.1 On July 1, 2020, Liberty filed with the New Hampshire Public Utilities Commission ("Commission") a Notice of Intent to File Rate Schedules pursuant to N.H. Code Admin. Rules Puc 1604.05. On July 31, 2020, the Company filed its Petition for Permanent and Temporary Rates ("Petition"), including proposed tariffs and rate schedules, testimony, attachments and other information supporting the Petition. Liberty's Petition requested that the Commission grant: (1) a permanent increase in Liberty's distribution rates effective with service rendered on or after September 1, 2020, designed to yield an increase of $13,497,250 in annual revenue above the then total Distribution Revenue of $86,698,260[1]; (2) temporary rates effective with service rendered on or after October 1, 2020, designed to yield an increase of $6,500,000 in annual revenue pending the Commission's final determination on the Company's request for a permanent rate increase; and (3) a step adjustment in rates designed to yield an increase of $5,680,641 in annual revenue to recover costs associated with approximately $38 million of capital expenditures projected to be placed in service during 2020, to be effective no earlier than August 1, 2021, and two additional step adjustments for capital expenditures projected to be placed in service in 2021 and 2022. The Petition requested approval of a 10.51 percent return on equity ("ROE"), and a capital structure consisting of 50.15 percent equity and 49.85 percent debt.

1.2 On July 8, 2020, the OCA filed a letter of participation in this docket pursuant to RSA 363:28. The Commission received no petitions for intervention in this docket by other parties.

1.3 On August 19, 2020, the Commission issued Order No. 26,395 suspending Liberty's proposed gas service tariff for temporary and permanent rate increases pending further investigation.

1.4 On September 16, 2020, the Commission held a hearing on temporary rates at which Liberty amended its request such that temporary rates would be set at current rates, and to approve a revenue requirement for temporary rates of $92,890,325, with the $4,994,290 increase in allowed revenues accomplished by adjusting the allowed revenue per customer ("RPC") amounts for each of Liberty's rate classes.[2] On September 30, 2020, the Commission issued Order No. 26,412

[1] The Distribution Revenue of $86,698,260 does not include revenue from Indirect COG Revenue and Other Revenue although both are included in total revenue requirement for the purpose of a distribution base rate case.

[2] The approved temporary rates revenue requirement of $92,890,325 does not include $1,993,588 from Indirect Cost of Gas (COG) Revenue.

approving Liberty's request for temporary rates effective with service rendered on and after October 1, 2020.

1.5 On October 5, 2020, the Commission approved an initial procedural schedule for adjudication of the Company's permanent rate request that included multiple rounds of discovery, technical sessions, settlement conferences, Staff and intervenor testimony, Company rebuttal testimony, and hearings. On November 20, 2020, the Company filed a motion to amend the Petition and supplemental pre-filed direct testimony in support of recovery of Granite Bridge Project costs.[3] The Commission subsequently amended the procedural schedule to accommodate the motion to amend the petition. On March 2, 2021, the Company filed an update to its proposed permanent rate request, including a total revenue requirement of $99,786,984[4] and a proposed permanent rate increase of $4,933,718[5]. Staff and OCA each filed testimony on March 18, 2021, and the Company filed rebuttal testimony on April 29, 2021.

1.6 Staff's testimony recommended the following: (1) an ROE of 9.0 percent and a capital structure of 49.21 percent equity and 50.79 percent long term debt; (2) a permanent decrease to revenue requirement of $2,240,114 below the temporary rate level; (3) one step increase for 2020 of $5,157,187 subject to audit, and no step adjustments for future years; and other proposed adjustments. OCA's testimony recommended an ROE of 8.9 percent, did not include a

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[3] The motion to amend the Petition was filed pursuant to the Commission's order in Docket No. DG 17-198 in connection with the Granite Bridge Project, in which the Commission held: "Requests for authority to recover capital project and supply planning costs are appropriately reviewed in a full rate case." Order No. 26,409 at 13 (Oct. 6, 2020).

[4] The $99,786,984 includes $4,027,585 of Indirect COG Revenue and $1,207,376 of Other Revenue.

[5] Bates II-132R. The requested rate increase of $4,933,718 plus the revenue increase at temporary rates of $4,994,290 equates to a revenue increase of $9,928,008.

recommendation for a capital structure different from the Company's proposal, and included other proposed adjustments and rate design elements.

1.7 In the weeks prior to and following the Company's submission of rebuttal testimony, the Company, Staff, and the OCA engaged in settlement discussions. Based upon these discussions, the Settling Parties agreed to the terms of this Settlement Agreement, subject to Commission approval. The Settling Parties recommend and request that the Commission approve this Settlement Agreement without modification.

SECTION 2. REVENUE REQUIREMENT

2.1 The Revenue Requirement consists of three subparts: (1) allowed revenue from distribution rates ("Distribution Revenue"); (2) allowed revenue from cost of gas rates ("Indirect COG Revenue"); and (3) revenue outside of rates such as special contract revenue and property leases ("Other Revenue"), (collectively referred to as the "Revenue Requirement").

In a decoupling framework a key metric is the increase in the Distribution Revenue. Distribution rates are then set to best achieve this Distribution Revenue and are reconciled through the revenue decoupling adjustment factor each year.

The following table summarizes the revenue requirement and revenue allocation agreements of the Settling Parties.

	A	B	C	D
	Proposed Approved Revenue Calculation			
1	Distribution Revenue ($84,591,458+$2,106,802)	$ 86,698,260		(Exhibit 5, line 1+3)
2	Indirect COG Revenue	$ 1,993,587		(Fixed Indirect)
3	Other Revenue	$ 1,197,776		(Exhibit 5, line 5)
4	**Total Approved Revenue from Test Year**		$ 89,889,623	(B1+B2+B3)
5	Increase to Distribution Revenue via Temp Rates Settlement	$ 4,994,290		(Exhibit 5, line 2+4)
6	**Total Approved Revenue After Temp Rates Settlement**		**$ 94,883,913**	(C4+B5)
7	Order 26,412 did not include COG of $1,993,587	$ (1,993,587)		Existing Indirect COG Allocation
8	**Temp Rate Order 26,412 rev requirement for temp rates**		**$ 92,890,326**	(C6+B7) Temp Rate Order 26,412
9	Settlement Increase to Approved Rev above Temp Rates	$ 1,300,000		Perm Rates Settlement Agreement
10	**Total Proposed Approved Revenue Increase from Test Year**	**$ 6,294,290**		(B5+B9)
11	**Total Approved Revenue per Settlement for the Test Year**		**$ 96,183,913**	(C6+B9)
12	Approved Distrib Revenue (Target Revenue on Rates 5)	$ 91,082,950		(C11-B13-B14) (tie to Rates 5)
13	Approved Indirect COG Revenue	$ 3,893,587		(B17)
14	Other Revenue	$ 1,207,376		(B3+$9,600 from Audit Issue 6)

	A	B	C	D
	Proposed Approved Revenue Allocation			
15	Total Increase in Approved Revenue	$ 6,294,290		(B5+B9)
16	Amount of increase allocated to Indirect COG 11/1/21*	$ 1,900,000		Perm Rates Settlement (COSS)
17	Total Indirect COG Revenue	$ 3,893,587		(B16-B7)
18	Remainder of increase allocated to Dist Rates	$ 4,394,290		(B15-B16)
19	Adj to Rates (Permanent Increase less Temp Increase)	$ (600,000)		(B18-B5)
20	Total Revenue Increase Above Temp per Settlement	$ 1,300,000		(B16+B19)
21	Indirect COG increase to be Allocated to EN & Keene	$ 1,900,000		(B16)
22	Indirect COG Allocation to Keene (Production Cost)*	$ 208,129		Perm Rates Settlement Agreement
23	Indirect COG Allocation to Energy North*	$ 1,691,871		(B21-B22)
	*Reconciled to 10/1/2020			

The Company shall be allowed a Revenue Requirement increase of $6,294,290, which is a $1.3 million increase above the level provided by temporary rates. Based on the cost of service study the Settling Parties agree that $1,900,000 of the $6,265,231 revenue increase shall be applied to the next COG proceeding as described in Section 13.3, effective for service rendered on and after November 1, 2021. In addition, a surcharge shall be added through the LDAC to reconcile this $1,900,000 addition to the Indirect COG Revenue back to the effective date of temporary rates of October 1, 2020. The remaining $4,394,290 in revenue requirement shall be collected from distribution rates effective for service rendered on and after August 1, 2021, to be reconciled back to October 1, 2020, the effective date of temporary rates, consistent with Order No. 26,412 (Sept.

30, 2020) in this proceeding. Because the temporary rate revenue increase was an increase of $4,994,290, the result is that the permanent rate change shall be a decrease of $600,000 from temporary rates. In addition, the reconciliation from temporary rates to permanent rates shall be a reduction to account for the over-collection of distribution rates that occurred from October 1, 2020, to the implementation of permanent rates.

2.2 The agreed Revenue Requirement increase of $6,265,231 includes the following cost of service elements: (1) recovery of costs associated with the New Hampshire Department of Administrative Services special contract of $1,047,589 over three years ($349,196/year); (2) amortization of excess accumulated deferred income tax ("EADIT") for protected property over 28.93 years and for non-protected property over 20 years as further described in Section 3.3; (3) amortization of remaining 'costs to achieve' from Docket No. DG 06-107 of $48,197 over three years ($16,066/year)[6]; (4) continued amortization of $1,657,796 per year for the depreciation reserve imbalance amortization, subject to adjustment based upon updated cost of removal and average service life information to be determined pursuant to Section 3.2 of this Settlement Agreement; and (5) the cost of capital provided in Section 4 of this Settlement Agreement.

2.3 The agreed revenue increase reflects adjustments that have been made in order to reach settlement and shall not establish precedent for future rate proceedings.

[6] As referenced in Schedule RR-EN-3-6, adjustment 6 from the March 2, 2021, Corrections and Update filing.

SECTION 3. RATE BASE

3.1 The lead/lag days in Cash Working Capital shall be 25.72.

3.2 The Company shall perform a study during calendar year 2021 based on a sampling of different sized 2021 mains and services capital projects to determine the cost of removal percentages that should be applied to mains and services. The Company shall also obtain a new full depreciation study based on 2021 end of year plant balances, which study shall review and incorporate the results of the cost of removal study. The depreciation study shall be used to assess and update the depreciation reserve imbalance by making the necessary adjustments to the annual amortization amount of $1,657,796. The determination of the depreciation lives and rates applicable to various plant accounts shall adjust the annual depreciation expense amounts. Liberty shall file the updated depreciation study along with a report on its findings by May 1, 2022, for review by Staff and the OCA as part of the second step adjustment review. Any adjustments based on the updated depreciation study shall be reflected in the second step increase to take effect on August 1, 2022.

3.3 As a result of tax law changes from the Tax Cuts and Jobs Act of 2017, Liberty has a total of $37,855,214 of excess accumulated deferred income tax liabilities that will be amortized as credits to the benefit of customers as follows: (i) protected items totaling $33,434,927 will be amortized as annual credit of $1,155,718 over 28.93 years; and (ii) unprotected items totaling $4,420,287 will be amortized as an annual credit of $221,014 over 20 years.

SECTION 4. COST OF CAPITAL

4.1 The Company shall be allowed a return on equity of 9.3 percent.

4.2 The Settling Parties have agreed that a capital structure of 52.0 percent equity and 48.0 percent debt shall be used for purposes of determining the Company's revenue requirement in this proceeding, which results in the following pre-tax and after-tax weighted average costs of capital based on the current federal and state tax rates and the Company's current cost of long-term debt:

Description	Capital Structure	Cost of Capital	Weighted Cost of Capital	Tax Rate	Pre-Tax
Common Stock	52.00%	9.30%	4.84%	27.08%	6.64%
Long-Term Debt	48.00%	4.420%	2.12%		2.12%
Total	100.00%		6.96%		8.76%

SECTION 5. STEP ADJUSTMENTS

5.1 The Company shall be allowed two step adjustments as follows:

(a) Step 1 shall reflect an increase to account for certain capital projects placed in service during calendar year 2020 and shall be implemented on August 1, 2021. This first step adjustment reflects adjustments that have been made to the revenue requirement in order to reach settlement. The first step shall be subject to the following conditions:

i. The revenue requirement for this step shall be capped at a $4.0 million increase to annual Distribution Revenue.

ii. The step shall be based on the projects closed to plant in 2020, and shall exclude new business/growth-related projects.

iii. The projects that may be included in the step are identified in the listing attached as Appendix 1.

iv. Local property taxes shall not be included in the calculation and will be recovered through the Property Tax Adjustment Mechanism in Section 6 of the Settlement Agreement. State utility property taxes for all projects listed in Appendix 1, calculated using the statutory tax rate in RSA 83-F:2, shall be included in the step adjustment calculation, shall count toward the cap, and shall be given first priority of recovery.

(b) Step 2 shall reflect an increase to account for certain capital projects placed in service during calendar year 2021 and shall be effective August 1, 2022. This second step adjustment reflects adjustments that have been made to the revenue requirement in order to reach settlement. The second step shall be subject to the following conditions:

i. The revenue requirement for this step shall be capped at a $3.2 million annual increase to Distribution Revenue from the projects referenced in iii. below.

ii. The step shall be based on the projects closed to plant in 2021, and shall exclude new business/growth-related projects.

iii. The projects and programs that may be included in this step are identified in the listing attached as Appendix 2, including Keene CNG Phase 1 costs as further described in Section 7.2. The Settling Parties agree that the Company may substitute other similar non-growth projects prior to the commencement of the review period if projects identified in Appendix 2 are not deployed.

iv. Local property taxes shall not be included in the calculation and will be recovered through the Property Tax Adjustment Mechanism in Section 6 of the Settlement Agreement. State property taxes for all projects listed in Appendix 2 as it may be adjusted pursuant to iii. above, calculated using the statutory tax rate in RSA 83-F:2, shall be included in the step adjustment calculation and shall be given first priority of recovery.

v. The step adjustment shall include adjustments resulting from the updated depreciation study as provided in Section 3.2 of the Settlement Agreement.

5.2 For the second step, the Company shall make a filing on or before April 8, 2022, with rates effective August 1, 2022. The filing shall include, at least, the following documentation and process steps:

(a) The Company shall provide the amount of the investments to be included in the step increase (by project) and detailed project descriptions including the initial budget, the final cost, the treatment of any related retirements, and the date each project was booked to plant in-service.

(b) For each project Liberty shall provide all Company project documents including, but not limited to, Business Cases, Capital Project Expenditure Applications, Change Order Forms, Project Close Out Reports, and work orders.

(c) Staff and/or the OCA may request additional information after reviewing the initial filings.

(d) The Company shall propose a rate increase effective August 1, 2022, to recover the revenue requirement associated with the second step adjustment up to the $3.2 million cap.

5.4 For the second step, if the actual cost of the capital additions is less than the budgeted amounts, the actual amounts shall be used to calculate the step adjustments. If the actual cost of the capital additions exceeds the budgeted amounts for a particular project, the Company may seek recovery of the excess through this step adjustment process, subject to the cap. The Company may otherwise seek recovery in its next rate case for any above-budget investments not approved in a step adjustment described here. The revenue requirement for the step adjustments will be calculated in a manner similar to that used in the Company's filing seeking approval of the first step adjustment. The step increase shall be subject to Staff audit and reconciliation based on the results of the audit, as approved by the Commission.

5.5 Nothing in this Settlement Agreement shall preclude Staff or the OCA from contesting the prudence of individual investments requested for recovery within the step increases.

5.6 The Company shall not request recovery of any capital costs associated with plant placed in service outside of the above-described step adjustments until the Company's next distribution rate case filing, which shall be based on a test year ending no sooner than December 31, 2022.

SECTION 6. PROPERTY TAX ADJUSTMENT MECHANISM

6.1 The Company shall be authorized to implement a Property Tax Adjustment Mechanism ("PTAM") to allow the Company to request recovery or refund of local property tax expenses, as compared to the amount in base rates, beginning with the April 1, 2020, through March 31, 2021, property tax year. Consistent with RSA 72:8-e, property tax over- or under-recoveries as compared to the amount in base distribution rates shall be adjusted annually through the PTAM. The amount included in base distribution rates for local property tax expense shall be $8,924,897, as shown in Appendix 3.

6.2 The PTAM shall be a fully reconciling property tax adjustment mechanism except for the exclusion of State of New Hampshire utility property taxes. The State of New Hampshire utility property taxes levied on the step eligible investments shall be collected as part of the step revenue requirement as detailed in Section 5 above.

6.3 On an annual basis beginning with the property tax year that commenced April 1, 2020, actual local property tax amounts from the property tax bills received during a calendar year[7] shall be compared against the amount in base rates as of the March 31 end of each property tax year, and any variances will be reconciled through the PTAM. With respect to the initial year of reconciliation, local property tax bills received during calendar year 2020 will be compared to the calculated amount in distribution rates through March 31, 2021, which includes the recoupment of the property tax amount reconciled between temporary and permanent rates. Reconciliation in subsequent years will be handled in a similar fashion. Annual property tax billed amounts shall be adjusted for any credits received due to abatement proceeds received for tax years preceding the test year. The PTAM shall reconcile and provide for recovery or credit for any over- or under-recoveries beginning with the April 1, 2020, through March 31, 2021, property tax year.

6.4 The PTAM shall be established annually based on a full reconciliation with monthly compounded interest for any over- or under-recoveries occurring in prior year(s). Interest shall be calculated at the prime rate, to be fixed on a quarterly basis and to be established as reported in

[7] Property tax bills received during a calendar year cover the annual property tax year that begins on April 1 and runs through the following March 31.

The Wall Street Journal on the first business day of the month preceding the calendar quarter ("Prime Rate").

6.5 The Company shall submit the initial PTAM filing covering the period described in Section 6.3 on or before August 20, 2021, and the PTAM distribution rate adjustment for that period shall be effective with service rendered on and after November 1, 2021. Filings covering subsequent property tax years shall be made on or before March 10 using property tax bills received during the prior calendar year for adjustments to distribution rates effective May 1.

6.6 Billing determinants used for adjusting the Revenue Per Customer (RPC) amounts for the initial PTAM adjustment, as described in Section 11, for the purpose of the PTAM adjustment, shall be the same as the calendar year 2020 billing determinants used for the purpose of the first step adjustment (see Section 5.1). Billing determinants used for subsequent PTAM adjustments shall be the annual billing determinants for the calendar year that corresponds to the year that the local property tax bills were received for that particular PTAM reconciliation.

SECTION 7. KEENE CONVERSION TO CNG

7.1 Keene Cost of Gas. The Company shall recover one-half of the incrementally higher CNG supply costs as compared to the propane supply cost,[8] incurred from the commencement of CNG service through October 31, 2021, to be recovered through inclusion over one year in the next Keene cost of gas during the winter or summer periods consistent with the season in which the incremental costs were originally incurred. The Company shall provide the supporting calculations

[8] Incremental CNG supply cost/savings shall be calculated by multiplying the CNG therm purchases by the difference between the average per therm CNG supply cost and the propane supply costs for the applicable summer/winter period. Average CNG supply costs shall include all CNG supplier charges properly allocated between summer and winter periods. Average propane supply costs shall include Mont Belvieu propane pricing, transportation costs, and Broker Fee.

in the Winter 2021-2022 Keene Cost of Gas filing. Incremental CNG supply costs through the 2020-2021 winter period are provided in Appendix 4.

(a) Beginning November 1, 2021, if the CNG supply cost is higher than the propane supply cost as described in footnote 8, the Company shall recover one-half of the incrementally higher CNG supply cost, as determined through the cost of gas reconciliation process. If the CNG supply cost is lower than the propane supply cost, the Company shall recover and retain the full amount of the incrementally lower CNG supply cost up to the amount of incrementally higher CNG costs accrued since the commencement of CNG service, which have not then been recovered from customers, at which point the Company shall recover and retain one-half of the incrementally lower CNG supply costs. Reconciliation of the incremental CNG supply costs shall occur semi-annually in the Winter and Summer Cost of Gas filings, as applicable. A sample calculation of incremental CNG supply costs/savings, using non-confidential, hypothetical pricing, is illustrated in Appendix 5.

(b) CNG demand costs shall be allocated 75% to the winter period and 25% to the summer period until such time as otherwise determined by the Commission in a future proceeding. Any change in allocation shall be implemented during a Winter Cost of Gas filing.

7.2 Keene Expansion. Phase 1 of the Keene conversion to natural gas shall consist of: (1) installation of the existing temporary CNG facility; (2) conversion of the propane-air customers premises at the Monadnock Marketplace to natural gas as of the date of this Settlement; and (3) acquisition of customers at any additional premises not currently physically connected to the gas utility system in Keene after the date of this settlement who would be served CNG from both the existing CNG temporary facility and through existing mains. An "existing main" is one that has a Maximum Allowable Operating Pressure ("MAOP") greater than 0.5 psig and that can be safely used to deliver natural gas, satisfying all applicable safety rules and regulations. Inclusion of additional customers in Phase 1 as described in this section (3) shall not change the time frame of the risk sharing mechanism. Revenue from new customers at existing premises converted from propane-air to CNG shall not be included in the discounted cash flow analysis of the risk sharing mechanism. The Settling Parties agree that the existence of Phase 1 shall not be used to justify any further development of CNG in Keene beyond Phase 1.

(a) The Company shall be allowed to seek recovery of the Phase 1 costs as part of the second step adjustment (excluding the cost of the Production Avenue land), subject to the risk sharing mechanism established in Order No. 26,122 (April 27, 2018) at 39 as clarified in Order No. 26,274 (July 26, 2019). The Company retains the right to seek recovery of the cost of the Production Avenue land at a future time. As part of the second step adjustment, the Company shall be allowed to update the recovery of the Phase 1 costs to account for the revenue and costs associated with additional Phase 1 customers who began taking service or committed to take service on or before August 1, 2022, the effective date of the step adjustment, subject to the risk sharing mechanism established in the above orders. If a customer committed to take service does not actually take service prior to the next base rate case then the August 1, 2022, risk sharing adjustment calculation shall be recalculated and any shortfall shall be adjusted accordingly to reflect the actual service. The adjustment for the risk-sharing mechanism for the Phase 1 investments included in rate base as of December 31, 2019, is $21,736 as outlined in Appendix 6, which amount is already taken into account in the revenue requirement described in Section 2.

(b) Phase 2 shall not be implemented until Liberty satisfies the conditions of Order No. 26,122 (Apr. 27, 2018) as clarified in Order No. 26,274 (July 26, 2019), and the Company's tariff, as applicable. Incremental revenue from Phase 1 new customers may not be used to justify Phase 2. If a customer who committed to take service does not actually take service prior to the effective date of temporary rates in the next base rate case then the risk sharing adjustment calculation shall be recalculated and any shortfall shall be adjusted accordingly to reflect the actual service.

(c) The Settling Parties agree that prior to the implementation of any future phase the ten year net present value of such phase shall not be negative.

(d) The following definitions shall apply to Phase 2 and future phases of the conversion of Keene customers from propane-air to natural gas (including renewable natural gas):

(i) A "phase" shall be one or more customer additions or conversions which require the installation of 100 feet or more of new main. The addition or conversion of new customers requiring less than 100 feet of new main shall not be a "phase," but shall comply with the Company's line extension tariff.

(ii) Converting existing main from propane-air to natural gas shall be considered a "new main" unless the existing main has an MAOP of greater than 0.5 psig and can be safely used to deliver natural gas, satisfying all applicable safety rules and regulations.

SECTION 8. PELHAM EXPANSION

8.1 The agreed revenue requirement includes a reduction of ($61,871) pursuant to the risk sharing mechanism approved by the Commission in Docket No. DG 15-362, in Order 29,987, based on the Company's discounted cash flow ("DCF") analysis that compares the revenue requirement of the take station on the Concord Lateral with the anticipated annual revenue from new Pelham customers. The anticipated revenue includes expected revenue from a large industrial customer who signed an agreement to take service in 2016, has not yet taken service for various reasons, but is still expected to take service from Liberty in the near future.

8.2 The Settling Parties agree to maintain this adjustment for the August 1, 2021 – July 31, 2022 rate year. If the large industrial customer has not taken service from Liberty on or before August 1, 2022, the anticipated revenue from this customer shall be removed from the DCF calculation and the adjustment to remove revenue from that customer shall be made in the second step adjustment.

SECTION 9. iNATGAS COSTS

9.1 Consistent with the Commission's determination in Docket No. DG 17-048, and in light of the increased capital costs associated with the iNATGAS CNG fueling facility, the Settling Parties agree that there will be a reduction of the overall revenue requirement of $301,747 for ratemaking purposes, such amount already being reflected in the Revenue Requirement increase described in Section 2.1, until the time of the Company's next distribution rate case.

SECTION 10. GRANITE BRIDGE COST RECOVERY EXCLUDED FROM SETTLEMENT

10.1 The Company's Petition, as amended, requests Commission approval for recovery of the costs incurred to investigate, evaluate, and assess the development of the Granite Bridge Project, which the Company calculates as approximately $7.5 million (the "Granite Bridge Project Costs"). The Settling Parties agree that the current rate case is the appropriate docket for adjudication of the Granite Bridge Project Costs. The recovery of the Granite Bridge Project Costs are excluded from this Settlement Agreement and shall be litigated within this proceeding.

SECTION 11. RATES AND RATE DESIGN

11.1 **Decoupling.** As this is the first general rate case since the implementation of decoupling, the Settling Parties agree that this is an opportunity to clarify the process surrounding the decoupling mechanism and the associated tariff language. The Agreement consists of five points regarding decoupling:

(a) The calculation of the revenue per customer (RPC) for permanent rates shall include:

i. the end of year calendar month bill count adjustment in the denominator of the calculation for the test year;

ii. the volumetric therms used for the calculation shall reflect the monthly bill counts adjusted for the end of year calendar month bill counts; and

iii. the RPC for the permanent rate increase shall not change until the next rate case.

(b) The calculation of the incremental revenue per customer for subsequent non-rate case rate changes such as, but not limited to, step adjustments, property tax reconciliation, and temporary rates, shall (i) use actual calendar month bill counts for the same time period being used to determine the calculation of each new RPC, and (ii) add each incremental RPC to the RPC from the rate case.

(c) Because the MEP Premium[9] is not subject to decoupling, the RPC calculations that are used to calculate the allowed revenue and the Revenue Decoupling Adjustment Factor shall not include the MEP Premium.

[9] MEP Premium is the premium charge to customers in the Managed Expansion Program. In Docket No. DG 17-048, the Commission approved the decoupling proposal in the settlement (Order 26,122 at 45) which states in part: "Managed Expansion Program customers are subject to decoupling, but the expansion surcharge dollars (i.e., the 30% distribution premium) are excluded from the decoupling calculation" (DG 17-048 Exhibit 29 at 11)

(d) Each month the Company shall record a Revenue Decoupling Adjustment (RDA) in the balance sheet RDA Accounts in accordance with generally accepted accounting principles, including: (i) the Revenue Decoupling Adjustment which is the difference between the Monthly Allowed Revenue and the Monthly Actual Distribution Revenue; (ii) the reconciliation amounts collected or distributed through the RDAF recorded in the RDA Accounts for each Customer Class Group; and (iii) the accrued interest on the RDA Accounts calculated on the average monthly balance using the prime lending rate.

(e) The RPC calculations, including equivalent bill calculations and associated usage per customer, shall be submitted with each rate increase filing and the associated tariff compliance filing.

The tariff has been amended as shown in Appendix 11 to effectuate the above understanding.

11.2 Revenue Calculations.

(a) **Indirect Gas Costs**. The Settling Parties agree to include $3,893,588 of Indirect COG Revenue for recovery through the COG which includes $1,900,000 of the revenue requirement increase identified in 2.1. The Indirect COG Revenue shall not change until the next rate case. The Indirect COG Revenue collected through COG rates shall be included in the revenue calculation for all future filings. The Settling Parties agree that the $3,893,588 of Indirect COG Revenue includes $206,248 of propane production costs allocated to Keene and $1,881 of Phase 1 conversion costs. The Keene COG tariff shall reflect the combined total of $208,129 as indirect gas costs.

(b) The Settling Parties agree that for purposes of calculating revenue in filings to the Commission the Company shall use the following guidelines:

i. The revenue per customer for low-income customers shall not be different from customers not categorized as low-income. The discount provided to low-income customers shall not be included in the revenue calculation as it is reconciled separately through the Gas Assistance Program (GAP) portion of the LDAC.

11.3 The Company's customer charges shall be set at the levels identified in Appendix 8. Thereafter, the Company's residential customer charges shall remain as set until the Company's next rate case. Specifically, any base rate increase and any surcharges or sur-credits for residential customers provided for in this Settlement Agreement shall be collected solely through changes in consumption charges for residential customers.

SECTION 12. TEST YEAR

12.1 The test year for the Company's next general distribution rate case shall be no sooner than the twelve-month period ending December 31, 2022.

SECTION 13. OTHER ISSUES

13.1 On or before November 30, 2021, the Settling Parties shall meet to review a list of regulatory reports currently required by the Commission, and discuss areas for potential elimination, consolidation, decreased frequency, and other measures to streamline reporting requirements. The Settling Parties shall submit individual or collective recommendations to the Commission following such meeting.

13.2 Liberty agrees to include in its Form F-1 quarterly rate of return reports adjustments of iNATGAS and risk sharing disallowances as described above. Reporting to include Indirect COG Revenue. Until changed in a future rate proceeding, the adjustment amounts shall be as follows: iNATGAS of $301,747, Keene risk sharing of $21,736, and Pelham risk sharing of $61,871.

SECTION 14. RECOUPMENT

14.1 Subject to Staff audit and adjustment for the difference between estimated and actual expense, the Company shall recover over one year $856,864.64 in rate case expenses commencing on November 1, 2021, through the LDAC mechanism, as shown on Appendix 9. The Company agrees to submit by August 1, 2021, an accounting of its rate case expenses, with appropriate supporting documentation, for review by Staff and the OCA and subsequent approval by the Commission. Staff shall provide its recommendation for rate case expense recovery to the parties as soon as reasonably possible, and the Company shall be authorized to recover the approved rate case expenses beginning with service rendered as of November 1, 2021. Any necessary adjustments to rate case expenses, including adjustments for any invoices received subsequent to the August 1, 2021, filing date, will be reviewed as part of the LDAC proceeding.

14.2 The permanent rate increase agreed to in Section 2.1 shall be effective for all service rendered on and after August 1, 2021.

14.3 **Distribution Revenue Reconciliation.** The difference between the Distribution Revenues obtained from the rates prescribed in the temporary rate order, Order No. 26,412, and the Distribution Revenues that would have been obtained under the rates designed to collect the Approved Distribution Revenue finally determined after review and approval of this Settlement Agreement, if applied during the period that the temporary rate order was in effect from October 1, 2020, to July 31, 2021, shall be returned to customers over a period of 12 months beginning with service rendered as of November 1, 2021. The total estimated amount of recoupment is ($570,933), as shown on Appendix 10, and shall be reconciled through the LDAC mechanism. Any necessary adjustments to the recoupment amount will be reviewed as part of the LDAC proceeding.

14.4 **Indirect COG Revenue Recoupment.** The difference between the Indirect COG Revenues obtained in accordance with Exhibit 5, of $1,993,587, and the Indirect COG Revenues that would have been obtained under the Approved Indirect COG Revenues finally determined after review and approval of this Settlement Agreement, if applied during the period since the temporary rate order, is $1,900,000 and shall be recovered over a period of 12 months through the LDAC mechanism. Any necessary adjustments to the recoupment amount will be reviewed as part of the LDAC proceeding.

SECTION 15. EFFECTIVE DATE

15.1 This Settlement Agreement is subject to and shall become effective upon Commission approval, with new permanent distribution rates to become effective as of August 1, 2021. The Settling Parties shall use best efforts to obtain Commission approval on or before July 30, 2021.

SECTION 16. GENERAL PROVISIONS

16.1 A revised tariff intended to incorporate the provisions of this Settlement Agreement is included as Appendix 11.

16.2 This Settlement Agreement is expressly conditioned upon the Commission's acceptance of all its provisions, without change or condition. If the Commission does not accept this Settlement Agreement in its entirety, without change or condition, or if the Commission makes any findings that go beyond the scope of this Settlement Agreement, and any of the Settling Parties notify the Commission within five business days of their disagreement with any such changes, conditions, or findings, the Agreement shall be deemed to be withdrawn, in which event it shall be deemed to be null and void and without effect, shall not constitute any part of the record in this proceeding, and shall not be relied on by Staff or any party to this proceeding or by the Commission for any other purpose.

16.3 Under this Settlement Agreement, the Settling Parties agree to this joint submission to the Commission as a resolution of the issues specified herein only.

16.4 The Settling Parties agree that the Commission's approval of this Settlement Agreement shall not constitute continuing approval of, or precedent for, any particular principle or issue, but such acceptance does constitute a determination that the adjustments and provisions stated in their totality are just and reasonable and consistent with the public interest and that the rates contemplated will be just and reasonable under the circumstances.

16.5 This Settlement Agreement shall not be deemed an admission by any of the Settling Parties that any allegation or contention in this proceeding by any other party, other than those specifically agreed to herein, is true and valid. This Settlement Agreement shall not be construed to represent any concession by any Settling Party hereto regarding positions taken with respect to the Company's proposals in this docket, nor shall this Settlement Agreement be deemed to foreclose any Settling Party in the future from taking any position in any subsequent proceedings. The amounts associated with each of the settlement adjustments detailed herein are liquidated amounts that reflect a compromise of all the issues in this proceeding

16.6 With the exception of pre-filed testimony and supporting documentation related to Granite Bridge Project Costs, the pre-filed testimony and supporting documentation previously provided in this proceeding are not expected to be subject to cross-examination by the Settling Parties, which would normally occur in a fully litigated case. The Settling Parties agree that all such pre-filed testimony and supporting documentation should be admitted as full exhibits for the purpose of consideration of this Settlement Agreement, and be given whatever weight the Commission deems appropriate. Consent by the Settling Parties to admit all such pre-filed testimony without challenge does not constitute agreement by any of the Settling Parties that the content of the pre-filed testimony is accurate or that the views of the witnesses should be assigned any particular weight by the Commission. The resolution of any specific issue in this Settlement Agreement does not indicate the Settling Parties' agreement to such resolution for purposes of any future proceedings, nor does the reference to any other document bind the Settling Parties to the contents of, or recommendations in, that document for purposes of any future proceeding. The Commission's approval of the recommendations in this Settlement Agreement shall not constitute a determination or precedent with regard to any specific adjustments, but rather shall constitute only a determination that the rates resulting from, and other specific conditions stated in this Settlement Agreement are just and reasonable. The Settling Parties agree to forego cross-examining witnesses regarding their pre-filed testimony and, therefore, the admission into evidence of any witness's testimony or supporting documentation shall not be deemed in any respect to constitute an admission by any party to this Agreement that any allegation or contention in this proceeding is true or false, except that the sworn testimony of any witness shall constitute an admission by such witness

16.7 The rights conferred and the obligations imposed on the Settling Parties by this Settlement Agreement shall be binding on or inure to the benefit of any successors in interest or assignees as if such successor or assignee was itself a signatory party. The Settling Parties agree to cooperate in advocating that this Settlement Agreement be approved by the Commission in its entirety and without modification.

16.8 The discussions that produced this Settlement Agreement have been conducted on the understanding that all offers of settlement and settlement discussions relating to this docket shall be confidential, shall not be admissible as evidence in this proceeding, shall be without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in connection with any future proceeding or otherwise. The content of these negotiations, including any documents prepared during such negotiations for the purpose of reaching a settlement, shall be privileged and all offers of settlement shall be without prejudice to the position of any party presenting such offer.

16.9 This Settlement Agreement may be executed by facsimile and in multiple counterparts, each of which shall be deemed to be an original, and all of which, taken together, shall constitute one agreement binding on all Settling Parties.

SECTION 17. CONCLUSION

17.1 The Settling Parties affirm that the proposed Settlement Agreement will result in just and reasonable rates and should be approved by the Commission.

Dated: June 29, 2021

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

____
By its Attorney, Michael J. Sheehan

Dated: June 29, 2021

Staff of the New Hampshire Public Utilities
Commission

/s/ Paul B. Dexter
____
By its Attorney, Paul B. Dexter

Dated: June 29, 2021

Office of the Consumer Advocate

____

By the Consumer Advocate, Donald M. Kreis

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Liberty Utilities (EnergyNorth Natural Gas) d/b/a Liberty
Non-Growth Projects Placed in Service During 2020

Project Number	Project Name	Priority	In service $$*	In service Date
8840-1911	Main Replacement LPP-Restoration	4. Regulatory Programs	$5,419,088	various
8840-1912	Install Main Baboosic Lake Rd at FE Everett Turnpike	5. Discretionary	($21,278)	carryover from 2019
8840-1921	Upgrade Synergi Software	5. Discretionary	$71,545	5/31/2020
8840-1933	Tilton Control panel replacement	1. Safety	$124,956	12/31/2020
8840-1936	Locusview place holder	5. Discretionary	$71,267	12/31/2020
8840-1945	Placeholder for Gas Training & Development	5. Discretionary	($534)	2019
8840-1953	Relocation of Engineering from Londonderry to Manchester	5. Discretionary	$4,000	5/3/2019
8840-2002	Meter Protection Program	2. Mandated	$797,741	12/31/2020
8840-2003	Cathodic Protection Program	2. Mandated	$565,735	12/31/2020
8840-2004	Replacement Services Random (Non Leaks)	2. Mandated	$629,257	12/31/2020
8840-2005	Replacement Services Random (Due to Leaks)	2. Mandated	$606,382	12/31/2020
8840-2008	Corrosion & Miscellaneous Fitting	2. Mandated	$308,724	12/31/2020
8840-2009	Valve Installation/Replacement	2. Mandated	$21,910	12/31/2020
8840-2010	Leak Repairs	2. Mandated	$2,139,714	7/7/2020 & 12/31/2020
8840-2011	Main Replacement LPP	4. Regulatory Programs	$7,193,378	various
8840-2013	Main Replacement Fitting LPP	5. Discretionary	$736,551	12/31/2020
8840-2014	K Meter Replacement Program	5. Discretionary	$275,342	12/31/2020
8840-2015	Aldyl-A Replacement Program	5. Discretionary	$80,424	carryover from billing related to city repaving
8840-2016	Main Replacement Reactive	5. Discretionary	$545,410	various
8840-2018	Purchase Misc Capital Equipment & Tools	1. Safety	$423,950	various
8840-2019	Regulator removal Hi line LOU	5. Discretionary	$1,956	8/12/2020
8840-2020	SCADA Capital Improvements	5. Discretionary	$129	2/3/2020
8840-2023	Main Replacement City/State Construction	2. Mandated	$7,415,807	various
8840-2025	Service Replacement Fitting City/State Construction	2. Mandated	$293,531	12/31/2020
8840-2026	LNG/LPG Capital Improvements	2. Mandated	$105,941	12/11/2020
8840-2028	Gas System Control & Regulation (ENG)	5. Discretionary	$400,008	various
8840-2029	Pre-Code Steel Pipe Protection Program/Replacement	2. Mandated	$63,836	12/31/2020
8840-2030	IT - Software, Equipment & Infrastructure	5. Discretionary	$63,413	5/1/2020
8840-2031	Gas System Planning & Reliability	5. Discretionary	$1,409,927	various
8840-2038	IT Systems Allocations - Corporate	5. Discretionary	$195,891	12/31/2020
8840-2039	Dresser Coupling Replacement Program	2. Mandated	$466,494	12/31/2020
8840-2043	iRestore System Enhancements	5. Discretionary	$347,138	12/31/2020
8840-2044	Flir Cameras - Security -Manchester	5. Discretionary	$717,164	12/19/2020
8840-2062	GIS Mapping	5. Discretionary	$273,898	12/31/2020
8840-2066	RTU Replacement Program	5. Discretionary	$34,289	12/31/2020
8840-2084	Electric Meter Worker Meter Training/Testing Wall	1.Safety	$24,926	7/31/2020
8840-2090	Transportation Fleet and Equipment Purchases	5. Discretionary	$1,739,571	various
8840-2091	Meter Work Project (Meter Purchases)	2. Mandated	$1,502,257	various
8840-2093	EN Facilities Capital Improvements	5. Discretionary	$520,763	various
8840-2094	Install Security Equipment - EN Facilities	2. Mandated	$37,561	various
8840-2096	Liberty @ Centre Vault Door	2. Mandated	$7,740	9/3/2020
8843-1820	Keene Propane Air Plant Meter Install	5. Discretionary	$12,233	in service 2018, $$ carryover
8843-2002	Replacement Services Random	2. Mandated	$286	in service 2019, $$ carryover
8843-2009	Service Replacement City/State Construction	2. Mandated	$313	in service 2019, $$ carryover
8843-2011	Main Replacement LPP	2. Mandated	$368,119	various
8843-2012	Capital Tools/Equipment	5. Discretionary	$2,426	12/31/2020
8843-2014	Gas System Planning & Reliability	5. Discretionary	$1,353	in service 2019, $$ carryover
8843-2090	Transportation Fleet and Equipment Purchases	5. Discretionary	($3,435)	8/31/2020, credit for vehicle upfitting
8843-2093	Facility Improvements & Additions - Keene	5. Discretionary	$64,185	11/30/2020
8843-2044	Flir Cameras - Security-Keene	5. Discretionary	$128,292	various
8843-2022	Propane Boiler Replacement	5. Discretionary	$16,842	10/23/2020
		Total	**$36,206,417**	

*In Service amounts may be greater than 2020 spend because there was spending in prior years for jobs put in service in 2020

Liberty Utilities (EnergyNorth)
Step Increase - EnergyNorth For Non-Growth Projects Placed In-Service During 2020

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Line	Description	Misc. Intangible Plant - 3 yr	Misc. Intangible Plant - 5 yr	LNG Plant	Mains	Station Equipment	Mains	Meas. & Reg. Station Equip.	Services	Meters	Office Equipment	Vehicles	Tools	Communication Equipment	Total
	FERC Account	*303*	*303*	*320*	*367*	*369*	*376*	*378*	*380*	*381*	*391*	*392*	*394*	*397*	
1	Capital Spending	$ 273,898	$ 677,987	$ 122,782	$ 25,939,975	$ 400,008	$ 466,494	$ 127,041	$ 1,529,769	$ 2,921,224	$ 1,479,706	$ 1,736,136	$ 425,842	$ 105,556	$ 36,206,417
2															
3	Deferred Tax Calculation														
4	Tax Method	MACRS15	MACRS15	MACRS20	MACRS20	MACRS20	MACRS20	MACRS20	MACRS20	MACRS20	MACRS7	MACRS5	MACRS7	MACRS7	
5	Tax Depreciation Rate	5.00%	5.00%	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%	14.29%	20.00%	14.29%	14.29%	
6															
7	Bonus Depreciation @ 0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8															
9	Tax Basis	$ 273,898	$ 677,987	$ 122,782	$ 25,939,975	$ 400,008	$ 466,494	$ 127,041	$ 1,529,769	$ 2,921,224	$ 1,479,706	$ 1,736,136	$ 425,842	$ 105,556	$ 36,206,417
10	MACRS Depreciation	$ 13,695	$ 33,899	$ 4,604	$ 972,749	$ 15,000	$ 17,494	$ 4,764	$ 57,366	$ 109,546	$ 211,387	$ 347,227	$ 60,835	$ 15,079	$ 1,863,645
11															
12	Tax Depreciation - Federal	$ 13,695	$ 33,899	$ 4,604	$ 972,749	$ 15,000	$ 17,494	$ 4,764	$ 57,366	$ 109,546	$ 211,387	$ 347,227	$ 60,835	$ 15,079	$ 1,863,645
13	Tax Depreciation - State	$ 13,695	$ 33,899	$ 4,604	$ 972,749	$ 15,000	$ 17,494	$ 4,764	$ 57,366	$ 109,546	$ 211,387	$ 347,227	$ 60,835	$ 15,079	
14															
15	Book Depreciation Rate	33.33%	20.00%	2.86%	1.92%	2.86%	1.92%	2.86%	3.55%	3.13%	5.28%	20.00%	5.26%	10.00%	
16	Book Depreciation	$ 91,290	$ 135,597	$ 3,512	$ 498,048	$ 11,440	$ 8,957	$ 3,633	$ 54,307	$ 91,434	$ 78,128	$ 347,227	$ 22,399	$ 10,556	$ 1,356,529
17															
18	Tax over (under) Book - Federal	$ (77,595)	$ (101,698)	$ 1,093	$ 474,702	$ 3,560	$ 8,537	$ 1,131	$ 3,060	$ 18,112	$ 133,258	$ -	$ 38,435	$ 4,524	$ 507,117
19	Tax over (under) Book - State	(77,595)	(101,698)	1,093	474,702	3,560	8,537	1,131	3,060	18,112	133,258	-	38,435	4,524	507,117
20	Deferred Taxes - Federal @ 19.38%	(15,040)	(19,712)	212	92,011	690	1,655	219	593	3,511	25,829	-	7,450	877	98,294
21	Deferred Taxes - State @ 7.70%	(5,975)	(7,831)	84	36,552	274	657	87	236	1,395	10,261	-	2,960	348	39,048
22	Deferred Tax Balance @ 0.00%	$ (21,015)	$ (27,543)	$ 296	$ 128,563	$ 964	$ 2,312	$ 306	$ 829	$ 4,905	$ 36,090	$ -	$ 10,409	$ 1,225	$ 136,117
23															
24	Rate Base Calculation														
25	Plant in Service	$ 273,898	$ 677,987	$ 122,782	$ 25,939,975	$ 400,008	$ 466,494	$ 127,041	$ 1,529,769	$ 2,921,224	$ 1,479,706	$ 1,736,136	$ 425,842	$ 105,556	$ 36,206,417
26	Accumulated Depreciation	(91,290)	(135,597)	(3,512)	(498,048)	(11,440)	(8,957)	(3,633)	(54,307)	(91,434)	(78,128)	(347,227)	(22,399)	(10,556)	(1,356,529)
27	Deferred Tax Balance	21,015	27,543	(296)	(128,563)	(964)	(2,312)	(306)	(829)	(4,905)	(36,090)	0	(10,409)	(1,225)	(137,342)
28	**Rate Base**	$ 203,623	$ 569,932	$ 118,975	$ 25,313,364	$ 387,604	$ 455,225	$ 123,101	$ 1,474,634	$ 2,824,885	$ 1,365,487	$ 1,388,908	$ 393,033	$ 93,776	$ 34,712,546
29															
30	Revenue Requirement Calculation														
31	Return on Rate Base @ 8.76%	$ 17,837	$ 49,926	$ 10,422	$ 2,217,451	$ 33,954	$ 39,878	$ 10,784	$ 129,178	$ 247,460	$ 119,617	$ 121,668	$ 34,430	$ 8,215	$ 3,040,819
32	Depreciation Expense	91,290	135,597	3,512	498,048	11,440	8,957	3,633	54,307	91,434	78,128	347,227	22,399	10,556	1,356,529
33	Property Tax @ $6.60 per $1000			810	171,204	2,640	3,079	838	10,096	19,280					207,948
34	**Annual Revenue Requirement**	**$ 109,128**	**$ 185,523**	**$ 14,744**	**$ 2,886,702**	**$ 48,034**	**$ 51,913**	**$ 15,255**	**$ 193,581**	**$ 358,174**	**$ 197,745**	**$ 468,896**	**$ 56,829**	**$ 18,770**	**$ 4,605,296**
35															
36															**Capped at $4,000,000**

Line	Rate of Return Calculation	Portion	After-Tax Cost	Pre-Tax WACC	Tax
37	Equity	52.0%	9.30%	6.64%	27.08%
38	Debt	48.0%	4.420%	2.12%	
39		100.0%		8.76%	

Liberty Utilities Capital Spending Plan

Spending 2021, Step Filing 2022

Project	CY 2021 Updated Budget Recovery 2022
Leak Repairs	$1,750,000
LPP-City/State	$23,050,010
Aldyl-A Replacement	$200,000
K Meter Replacement Program	$350,000
Main Replacement Reactive	$600,000
Dresser Coupling Replacement	$500,000
Gas System Planning & Reliability	$2,900,000
Gas Supply System Enhancements	$0
Customer First	$0
Total	$29,350,010

Liberty Utilities (EnergyNorth)
Step Increase - EnergyNorth For Non-Growth Projects Placed In-Service During 2021

Line	Description	Mains	Mains	Meters	Total
	FERC Account	*367*	*376*	*381*	
1	Capital Spending	$ 28,500,010	$ 500,000	$ 350,000	$ 29,350,010
2					
3	Deferred Tax Calculation				
4	Tax Method	MACRS20	MACRS20	MACRS20	
5	Tax Depreciation Rate	3.75%	3.75%	3.75%	
6					
7	Bonus Depreciation @ 0.00%	$ -	$ -	$ -	$ -
8					
9	Tax Basis	$ 28,500,010	$ 500,000	$ 350,000	$ 29,350,010
10	MACRS Depreciation	$ 1,068,750	$ 18,750	$ 13,125	$ 1,100,625
11					
12	Tax Depreciation - Federal	$ 1,068,750	$ 18,750	$ 13,125	$ 1,100,625
13	Tax Depreciation - State	$ 1,068,750	$ 18,750	$ 13,125	
14					
15	Book Depreciation Rate	1.92%	1.92%	3.13%	
16	Book Depreciation	$ 547,200	$ 9,600	$ 10,955	$ 567,755
17					
18	Tax over (under) Book - Federal	$ 521,550	$ 9,150	$ 2,170	$ 532,870
19	Tax over (under) Book - State	521,550	9,150	2,170	532,870
20	Deferred Taxes - Federal @ 19.38%	101,092	1,774	421	103,286
21	Deferred Taxes - State @ 7.70%	40,159	705	167	41,031
22	Deferred Tax Balance @ 0.00%	$ 141,251	$ 2,478	$ 588	$ 144,317
23					
24	Rate Base Calculation				
25	Plant in Service	$ 28,500,010	$ 500,000	$ 350,000	$ 29,350,010
26	Accumulated Depreciation	(547,200)	(9,600)	(10,955)	(567,755)
27	Deferred Tax Balance	(141,251)	(2,478)	(588)	(144,317)
28	**Rate Base**	$ 27,811,558	$ 487,922	$ 338,457	$ 28,637,938
29					
30	Revenue Requirement Calculation				
31	Return on Rate Base @ 8.76%	$ 2,436,293	$ 42,742	$ 29,649	$ 2,508,683
32	Depreciation Expense	547,200	9,600	10,955	$ 567,755
33	Property Tax @ $6.60 per $1000	188,100	3,300	2,310	193,710
34	**Annual Revenue Requirement**	**$ 3,171,593**	**$ 55,642**	**$ 42,914**	**$ 3,270,149**
35					
36					**Capped at $3,200,000**
37					
38	Rate of Return Calculation	Portion	After-Tax Cost	Pre-Tax WACC	Tax
39	Equity	52.0%	9.30%	6.64%	27.08%
40	Debt	48.0%	4.420%	2.12%	
41		100.0%		8.76%	

EnergyNorth
Municipal Property Taxes Included In Current Rates As Of March 31, 2021

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Line	Amount	Reference	Source
1	$9,259,401	EnergyNorth Total Property Tax	Included in Page 6 of 16 Line 24 in Appendix 1 from Order No. 26,122 in Docket No. DG 17-048
2	$153,854	Keene Total Property Tax	Included in Page 6 of 16 Line 24 in Appendix 1 from Order No. 26,122 in Docket No. DG 17-048
3	($1,952,162)	EnergyNorth State Property Taxes	Included in Page 6 of 16 Line 24 in Appendix 1 from Order No. 26,122 in Docket No. DG 17-048
4	($15,492)	Keene State Property Taxes	Included in Page 6 of 16 Line 24 in Appendix 1 from Order No. 26,122 in Docket No. DG 17-048
5	$7,445,601	2016 Municipal Property Taxes	Sum of Lines 1 through 4
6	$187,530	2017 CIBS	Annual incremental property taxes multiplied by the 2016 Municipal Property Tax %
7	$153,572	2018 CIBS	Annual incremental property taxes multiplied by the 2016 Municipal Property Tax %
8	$332,299	2018 Capital Step Increase (2017 Investment)	Appendix 4 from Order No. 26,122 in Docket No. DG 17-048 multiplied by the 2016 Municipal Property Tax %
9	$90,647	2019 CIBS	Annual incremental property taxes multiplied by the 2016 Municipal Property Tax %
10	$90,249	2020 CIBS (Jul 2020 - Sep 2020)	Three months of annual incremental property taxes multiplied by the 2016 Municipal Property Tax %
11	$624,999	DG 20-105 Reconciliation (Oct 2020 - Mar 2021)	Temp to Perm Reconciliation to Recoupment (Oct 2020 - Mar 2021)
12	$8,924,897	Calculated Municipal Property Taxes Included In Rates Through March 31, 2021	
13			
14	$10,000,000	Hypothetical Municipal Property Taxes Billed April 2020 - March 2021	
15	$0	Hypothetical Abatements or Other Adjustments	
16	$10,000,000	Hypothetical Adjusted Municipal Property Taxes Billed April 2020 - March 2021	Line 14 plus Line 15
17			
18	$1,075,103	Increase To Base Rates Due To Municipal Property Tax Reconciliation	Line 16 minus Line 12

Incremental CNG Supply Costs through October 2021
Amount to be Recovered/(Refunded) Through Keene COG Rates

CNG Increment Cost/Saving Risk Sharing - 50% Shareholder/Ratepayers				
Incremental CNG Supply Costs - October 2019 thru October 2021				
COG Period	Year	Amount	Deferred	(Refund)/Charge
Summer	2019	5,048		(2,524)
Winter	2019-20	132,469	132,533	66,299
Summer	2020	16,214	16,214	8,107
Winter - Note 1	2020-21	136,525		(68,263)
Summer - Note 2	2021	4,012		(2,006)
Total Summer		25,274	16,214	3,577
Total Winter		268,994	132,533	(1,964)
Combined Total		294,268	148,747	1,613

Note 1 - Estimated CNG incremental cost based on projected usage and costs filed in DG 20-152 (Keene 2020-2021 Winter COG). Actual CNG incremental costs/savings to be determined in Keene 2021-2022 Winter COG.

Note 2 - Estimated CNG incremental cost based on projected usage and costs filed in DG 21-050 (Keene 2021 Summer COG). Actual CNG incremental costs/savings to be determined in Keene 2022 Summer COG.

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ILLUSTRATION - CALCULATION OF PROJECTED INCREMENTAL CNG COST/SAVING TO BE INCLUDED IN COG RATES
TO BE RECONCILED USING ACTUAL COST - SUBSEQUENT COG RATES ADJUSTED FOR OVER/UNDER RECOVERY
See Line No. 22, 28, 42 and 45

LIBERTY UTILITIES - KEENE DIVISION

CALCULATION OF PURCHASED GAS COSTS
SUMMER PERIOD 20XX

LINE NO.		May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	TOTAL
1	TOTAL SENDOUT (therms)	60,000	40,000	50,000	40,000	50,000	80,000	320,000
2	CHANGE TO ENDING INVENTORY BALANCE (therms)	-	-	-	-	-	-	-
3	TOTAL REQUIRED PURCHASES (therms)	60,000	40,000	50,000	40,000	50,000	80,000	320,000
4	**PROPANE PURCHASE STABILIZATION PLAN DELIVERIES**							
5	Therms	-	-	-	-	-	-	-
6	RATES - from Schedule D							
7	Contract Price	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
8	Broker Fee	incl.	incl.	incl.	incl.	incl.	incl.	
9	Pipeline Fee	incl.	incl.	incl.	incl.	incl.	incl.	
10	PERC Fee	incl.	incl.	incl.	incl.	incl.	incl.	
11	Trucking Fee	incl.	incl.	incl.	incl.	incl.	incl.	
12	COST PER GALLON	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
13	TOTAL COST - Propane Purchase Stabilization Plan Deliveries	$0	$0	$0	$0	$0	$0	$0
14	**AMHERST STORAGE PROPANE DELIVERIES**							
15	Therms	-	-	-	-	-	-	-
16	RATES - from Schedule F							
17	WACOG Price	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
18	Trucking Fee	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
19	COST PER GALLON	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
20	TOTAL COST - Amherst Storage Propane Deliveries	$0	$0	$0	$0	$0	$0	$0
21	**CNG DELIVERIES**							
22	Therms	9,000	10,000	10,000	10,000	10,000	13,500	62,500
23	RATE							
24	PRICE	$ 0.8000	$ 0.8500	$ 0.9000	$ 0.9000	$ 0.9000	$ 0.9000	
25	COST PER Therm	$ 0.8000	$ 0.8500	$ 0.9000	$ 0.9000	$ 0.9000	$ 0.9000	
26	COST - CNG	$7,200	$8,500	$9,000	$9,000	$9,000	$12,150	
27	DEMAND FIXED	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$24,000
28	CNG COST PER Therm (line 29/22)	$ 1.2444	$ 1.2500	$ 1.3000	$ 1.3000	$ 1.3000	$ 1.1963	
29	TOTAL CNG (line 26+27)	$11,200	$12,500	$13,000	$13,000	$13,000	$16,150	$78,850
30	**SPOT PURCHASES**							
31	Therms	50,000	30,000	40,000	30,000	40,000	65,000	255,000
32	RATES - from Schedule C							
33	Mont Belvieu	$0.8500	$0.8000	$0.7500	$0.7500	$0.8000	$0.8500	
34	Broker Fee	$0.0100	$0.0100	$0.0100	$0.0100	$0.0100	$0.0100	
35	Pipeline Fee	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
36	PERC Fee	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
37	Supplier Charge	$0.2000	$0.2000	$0.2000	$0.2000	$0.2000	$0.2000	
38	Trucking Fee	$0.1000	$0.1000	$0.1000	$0.1000	$0.1000	$0.1000	
39	COST PER GALLON - Market Quotes	$1.1650	$1.1150	$1.0650	$1.0650	$1.1150	$1.1650	
40	COST PER THERM - Market Quotes	$1.1650	$1.1150	$1.0650	$1.0650	$1.1150	$1.1650	
41	TOTAL COST - Spot Purchases	$58,250	$33,450	$42,600	$31,950	$44,600	$75,725	$286,575
42	SPOT PURCHASES -COST PER Therm (line 41/31)	$1.1650	$1.2150	$1.1650	$1.1650	$1.2150	$1.2650	
43	**OTHER ITEMS**							
44	Storage - Winter Period 20XX-20XX	$0	$0	$0	$0	$0	$0	$0
45	50% Increment CNG (line (28 - 42) * 22*50%)	($358)	($175)	($675)	($675)	($425)	$464	($1,844)
46	TOTAL OTHER ITEMS	($358)	($175)	($675)	($675)	($425)	$464	($1,844)
47	**TOTAL**							
48	THERMS (line 5+15+22+31)	59,000	40,000	50,000	40,000	50,000	78,500	317,500
49	SENDOUT THERMS (line 1)	60,000	40,000	50,000	40,000	50,000	80,000	320,000
50	COST (line 13+20+29+41+46)	$69,093	$45,775	$54,925	$44,275	$57,175	$92,339	$363,581
51	COST PER THERM (line 50/48)	$1.1711	$1.1444	$1.0985	$1.1069	$1.1435	$1.1763	$1.1451

** Shaded cells show what information is considered confidential in future Keene COG filings

Keene Risk Sharing Adjustment
Update DCF Analysis for Keene Phase 1 Conversion

Capital Cost Direct (12/31/19 Rate Base)	$359,889
Required Return (pre tax)	8.75%
Depreciation	8,997
Property tax rate	1.94%
Insurance rate	0.10%
NPV (Delta yrs 1-10, discount rate 10.15%)	($270,681.69)

Risk Sharing Calculation Permanent Rates Take Effect Year 2	
Average revenue (years 2-4)	$0
Average revenue requirement (years 2-4)	$44,297
Difference	($44,297)
Revenue Requirement Reduction (50%)	($22,149)
Adjustment to Distribution (91.51%)	($20,268)
Adjustment to COG (8.49%)	($1,880)

Year	IRS MACRS Rates	IRS MACRS Table	Book Depr	Delta Book less Tax	Tax Rate	Deferred Inc Tax	Accumulated Deferred Inc Tax	Rate Base	Required Return	Property Tax	Insurance	O&M	Revenue Requirement	Annual Revenues	Delta Rev Req less Revenue
			(40 yrs/2.5%)							1.94%	0.10%	$ 35			
								359,889							
1	5.00%	17,994	8,997	(8,997)	27%	(2,436)	(2,436)	348,456	$31,003	$6,971	$360	$0	$47,331	$0.00	($47,330.75)
2	9.50%	34,189	8,997	(25,192)	27%	(6,822)	(9,259)	332,636	$29,810	$6,750	$360	$0	$45,916	$0.00	($45,916.48)
3	8.55%	30,771	8,997	(21,773)	27%	(5,896)	(15,155)	317,743	$28,466	$6,443	$360	$0	$44,266	$0.00	($44,265.84)
4	7.70%	27,711	8,997	(18,714)	27%	(5,068)	(20,223)	303,678	$27,198	$6,155	$360	$0	$42,710	$0.00	($42,709.91)
5	6.93%	24,940	8,997	(15,943)	27%	(4,317)	(24,540)	290,363	$26,000	$5,882	$360	$0	$41,239	$0.00	($41,239.13)
6	6.23%	22,421	8,997	(13,424)	27%	(3,635)	(28,175)	277,731	$24,864	$5,624	$360	$0	$39,846	$0.00	($39,845.58)
7	5.90%	21,233	8,997	(12,236)	27%	(3,314)	(31,489)	265,420	$23,772	$5,380	$360	$0	$38,509	$0.00	($38,509.19)
8	5.90%	21,233	8,997	(12,236)	27%	(3,314)	(34,802)	253,109	$22,695	$5,141	$360	$0	$37,193	$0.00	($37,193.10)
9	5.91%	21,269	8,997	(12,272)	27%	(3,323)	(38,126)	240,789	$21,617	$4,903	$360	$0	$35,877	$0.00	($35,876.58)
10	5.90%	21,233	8,997	(12,236)	27%	(3,314)	(41,439)	228,478	$20,539	$4,664	$360	$0	$34,560	$0.00	($34,559.87)
11	5.91%	21,269	8,997	(12,272)	27%	(3,323)	(44,762)	216,157	$19,461	$4,426	$360	$0	$33,243	$0.00	($33,243.36)
12	5.90%	21,233	8,997	(12,236)	27%	(3,314)	(48,076)	203,846	$18,383	$4,187	$360	$0	$31,927	$0.00	($31,926.65)
13	5.91%	21,269	8,997	(12,272)	27%	(3,323)	(51,399)	191,526	$17,305	$3,949	$360	$0	$30,610	$0.00	($30,610.14)
14	5.90%	21,233	8,997	(12,236)	27%	(3,314)	(54,713)	179,215	$16,226	$3,710	$360	$0	$29,293	$0.00	($29,293.43)
15	5.91%	21,269	8,997	(12,272)	27%	(3,323)	(58,036)	166,895	$15,148	$3,471	$360	$0	$27,977	$0.00	($27,976.92)
16	2.95%	10,617	8,997	(1,620)	27%	(439)	(58,475)	157,459	$14,196	$3,233	$360	$0	$26,786	$0.00	($26,786.04)
17			8,997	8,997	27%	2,436	(56,038)	150,898	$13,496	$3,050	$360	$0	$25,903	$0.00	($25,903.14)
18			8,997	8,997	27%	2,436	(53,602)	144,337	$12,922	$2,923	$360	$0	$25,202	$0.00	($25,201.76)
19			8,997	8,997	27%	2,436	(51,165)	137,776	$12,347	$2,796	$360	$0	$24,500	$0.00	($24,500.38)
20			8,997	8,997	27%	2,436	(48,729)	131,216	$11,773	$2,669	$360	$0	$23,799	$0.00	($23,798.99)

Required Return (Liberty proposal)				
Equity	52%	9.30%	12.75%	6.63%
Debt	48%	4.42%	4.42%	2.12%
				8.75%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Docket DG 20-105
Revenue Decoupling Adjustment
Rates Eff. 8/1/2021

Docket N0. DG 20-105
Appendix 7
Page 1 of 1

Permanent Rates
Revenue Per Customer

Rate Class	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$ 26.014	$ 25.540	$ 24.307	$ 22.609	$ 20.956	$ 19.755	$ 18.931	$ 19.019	$ 19.435	$ 20.546	$ 22.982	$ 25.299
R-3/6	$ 97.157	$ 93.255	$ 74.713	$ 50.567	$ 34.034	$ 25.472	$ 22.948	$ 23.085	$ 25.352	$ 37.025	$ 62.207	$ 83.921
R-4/7	$ 97.157	$ 93.255	$ 74.713	$ 50.567	$ 34.034	$ 25.472	$ 22.948	$ 23.085	$ 25.352	$ 37.025	$ 62.207	$ 83.921
G-41/44	$ 235.956	$ 226.979	$ 184.606	$ 128.146	$ 88.800	$ 70.623	$ 66.093	$ 66.385	$ 70.916	$ 94.488	$ 154.776	$ 204.268
G-42/45	$ 1,578.472	$ 1,524.667	$ 1,241.555	$ 855.091	$ 523.642	$ 346.741	$ 294.872	$ 301.796	$ 360.170	$ 572.697	$ 1,034.777	$ 1,394.253
G-43/46	$ 8,928.306	$ 8,426.278	$ 7,012.866	$ 4,981.917	$ 1,969.310	$ 1,450.046	$ 1,304.759	$ 1,372.855	$ 1,462.191	$ 2,016.955	$ 5,871.987	$ 7,656.083
G-51/55	$ 133.825	$ 130.979	$ 121.907	$ 111.427	$ 104.493	$ 98.646	$ 94.516	$ 98.006	$ 98.750	$ 101.809	$ 115.084	$ 126.203
G-52/56	$ 731.471	$ 706.568	$ 650.770	$ 576.938	$ 402.135	$ 377.110	$ 367.473	$ 377.804	$ 384.365	$ 407.882	$ 611.436	$ 669.830
G-53/57	$ 6,797.367	$ 6,197.111	$ 5,755.166	$ 4,877.206	$ 2,508.532	$ 2,307.268	$ 2,328.947	$ 2,476.034	$ 2,356.654	$ 2,625.619	$ 5,366.438	$ 6,077.525
G-54/58	$ 3,719.928	$ 3,726.283	$ 3,387.343	$ 3,833.707	$ 2,775.284	$ 2,874.002	$ 2,966.625	$ 3,090.866	$ 2,982.545	$ 2,965.834	$ 4,662.611	$ 3,822.712

Step Increase
Revenue Per Customer

Rate Class	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$ 1.483	$ 1.402	$ 1.264	$ 0.987	$ 0.742	$ 0.563	$ 0.464	$ 0.461	$ 0.537	$ 0.767	$ 1.196	$ 1.535
R-3/6	$ 4.968	$ 4.490	$ 3.576	$ 2.178	$ 1.178	$ 0.590	$ 0.464	$ 0.462	$ 0.630	$ 1.405	$ 3.017	$ 4.353
R-4/7	$ 4.968	$ 4.490	$ 3.576	$ 2.178	$ 1.178	$ 0.590	$ 0.464	$ 0.462	$ 0.630	$ 1.405	$ 3.017	$ 4.353
G-41/44	$ 10.371	$ 9.551	$ 7.771	$ 5.376	$ 3.848	$ 2.999	$ 2.860	$ 2.877	$ 3.115	$ 4.296	$ 6.950	$ 9.342
G-42/45	$ 71.556	$ 65.275	$ 52.763	$ 33.854	$ 20.781	$ 13.163	$ 11.663	$ 12.053	$ 14.984	$ 26.315	$ 47.308	$ 64.023
G-43/46	$ 322.176	$ 307.458	$ 260.216	$ 188.058	$ 125.272	$ 80.674	$ 74.052	$ 74.222	$ 90.747	$ 148.398	$ 230.190	$ 306.060
G-51/55	$ 6.156	$ 6.082	$ 5.241	$ 4.545	$ 4.182	$ 4.099	$ 4.023	$ 4.113	$ 4.243	$ 4.825	$ 5.232	$ 5.946
G-52/56	$ 31.400	$ 30.740	$ 24.341	$ 20.081	$ 17.238	$ 17.150	$ 17.025	$ 17.535	$ 18.199	$ 21.044	$ 23.978	$ 27.933
G-53/57	$ 246.248	$ 243.066	$ 214.654	$ 186.181	$ 150.341	$ 140.629	$ 138.297	$ 140.255	$ 144.706	$ 168.388	$ 188.258	$ 211.553
G-54/58	$ 138.456	$ 145.419	$ 124.103	$ 143.307	$ 136.199	$ 145.470	$ 155.194	$ 160.877	$ 160.145	$ 160.192	$ 161.125	$ 137.154

Total
Revenue Per Customer

Rate Class	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$ 27.498	$ 26.942	$ 25.571	$ 23.596	$ 21.698	$ 20.318	$ 19.395	$ 19.480	$ 19.972	$ 21.314	$ 24.178	$ 26.834
R-3/6	$ 102.124	$ 97.745	$ 78.289	$ 52.745	$ 35.212	$ 26.062	$ 23.412	$ 23.547	$ 25.982	$ 38.431	$ 65.224	$ 88.274
R-4/7	$ 102.124	$ 97.745	$ 78.289	$ 52.745	$ 35.212	$ 26.062	$ 23.412	$ 23.547	$ 25.982	$ 38.431	$ 65.224	$ 88.274
G-41/44	$ 246.326	$ 236.530	$ 192.376	$ 133.522	$ 92.648	$ 73.622	$ 68.954	$ 69.262	$ 74.031	$ 98.783	$ 161.726	$ 213.610
G-42/45	$ 1,650.029	$ 1,589.942	$ 1,294.318	$ 888.944	$ 544.422	$ 359.904	$ 306.536	$ 313.849	$ 375.153	$ 599.012	$ 1,082.085	$ 1,458.276
G-43/46	$ 9,250.482	$ 8,733.736	$ 7,273.082	$ 5,169.975	$ 2,094.582	$ 1,530.720	$ 1,378.810	$ 1,447.077	$ 1,552.938	$ 2,165.354	$ 6,102.177	$ 7,962.143
G-51/55	$ 139.981	$ 137.061	$ 127.148	$ 115.972	$ 108.676	$ 102.744	$ 98.539	$ 102.119	$ 102.993	$ 106.634	$ 120.316	$ 132.149
G-52/56	$ 762.870	$ 737.308	$ 675.111	$ 597.019	$ 419.373	$ 394.261	$ 384.498	$ 395.340	$ 402.564	$ 428.926	$ 635.414	$ 697.763
G-53/57	$ 7,043.615	$ 6,440.177	$ 5,969.820	$ 5,063.387	$ 2,658.873	$ 2,447.898	$ 2,467.245	$ 2,616.288	$ 2,501.361	$ 2,794.007	$ 5,554.697	$ 6,289.078
G-54/58	$ 3,858.384	$ 3,871.702	$ 3,511.446	$ 3,977.013	$ 2,911.483	$ 3,019.472	$ 3,121.818	$ 3,251.743	$ 3,142.690	$ 3,126.025	$ 4,823.736	$ 3,959.866

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE R-1 : RESIDENTIAL NON-HEATING

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
1	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
2	Cost of Gas	$0.4737	$0.3935	Cost of Gas	$0.5010	$0.3935
3	LDAC	$0.0589	$0.0589	LDAC	$0.0589	$0.0589
4						
5	Customer charge	$15.50		Customer charge	$15.39	
6	Sales rate			Sales rate		
7	First Block Size			First Block Size		
8	Block 1	$0.3860	$0.3860	Block 1	$0.4358	$0.4358
9	Block 2	$0.3860	$0.3860	Block 2	$0.4358	$0.4358
10						
11						

Line		Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13	Use per	Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14	Month (therms)	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																					
16	0	$15.50	$0.00	$15.50	$15.50	$0.00	$15.50	$15.39	$0.00	$15.39	$15.39	$0.00	$15.39	-$0.11	-0.7%	-$0.11	-0.7%	$0.0000	$0.0000	$0.0000	$0.0000
17	2	$16.27	$1.07	$17.34	$16.27	$0.90	$17.18	$16.26	$1.12	$17.38	$16.26	$0.90	$17.17	$0.05	0.3%	-$0.01	0.0%	$8.6686	$8.5884	$8.6919	$8.5844
18	4	$17.04	$2.13	$19.17	$17.04	$1.81	$18.85	$17.14	$2.24	$19.38	$17.14	$1.81	$18.95	$0.20	1.0%	$0.09	0.5%	$4.7936	$4.7134	$4.8438	$4.7363
19	6	$17.82	$3.20	$21.01	$17.82	$2.71	$20.53	$18.01	$3.36	$21.37	$18.01	$2.71	$20.72	$0.36	1.7%	$0.19	0.9%	$3.5019	$3.4217	$3.5611	$3.4536
20	8	$18.59	$4.26	$22.85	$18.59	$3.62	$22.21	$18.88	$4.48	$23.36	$18.88	$3.62	$22.50	$0.51	2.2%	$0.29	1.3%	$2.8561	$2.7759	$2.9198	$2.8123
21	10	$19.36	$5.33	$24.69	$19.36	$4.52	$23.88	$19.75	$5.60	$25.35	$19.75	$4.52	$24.27	$0.66	2.7%	$0.39	1.6%	$2.4686	$2.3884	$2.5350	$2.4275
22	15	$21.29	$7.99	$29.28	$21.29	$6.79	$28.08	$21.93	$8.40	$30.33	$21.93	$6.79	$28.72	$1.05	3.6%	$0.64	2.3%	$1.9519	$1.8717	$2.0219	$1.9144
23	20	$23.22	$10.65	$33.87	$23.22	$9.05	$32.27	$24.11	$11.20	$35.31	$24.11	$9.05	$33.16	$1.44	4.2%	$0.89	2.8%	$1.6936	$1.6134	$1.7654	$1.6578
24	25	$25.15	$13.32	$38.47	$25.15	$11.31	$36.46	$26.29	$14.00	$40.29	$26.29	$11.31	$37.60	$1.82	4.7%	$1.14	3.1%	$1.5386	$1.4584	$1.6114	$1.5039
25	30	$27.08	$15.98	$43.06	$27.08	$13.57	$40.65	$28.47	$16.80	$45.26	$28.47	$13.57	$42.04	$2.21	5.1%	$1.39	3.4%	$1.4353	$1.3551	$1.5088	$1.4013
26	35	$29.01	$18.64	$47.65	$29.01	$15.83	$44.84	$30.65	$19.60	$50.24	$30.65	$15.83	$46.48	$2.59	5.4%	$1.64	3.6%	$1.3615	$1.2813	$1.4355	$1.3280
27	40	$30.94	$21.30	$52.24	$30.94	$18.10	$49.04	$32.83	$22.40	$55.22	$32.83	$18.10	$50.92	$2.98	5.7%	$1.89	3.8%	$1.3061	$1.2259	$1.3805	$1.2730
28	45	$32.87	$23.97	$56.84	$32.87	$20.36	$53.23	$35.00	$25.20	$60.20	$35.00	$20.36	$55.36	$3.36	5.9%	$2.13	4.0%	$1.2630	$1.1828	$1.3378	$1.2303
29	50	$34.80	$26.63	$61.43	$34.80	$22.62	$57.42	$37.18	$28.00	$65.18	$37.18	$22.62	$59.80	$3.75	6.1%	$2.38	4.2%	$1.2286	$1.1484	$1.3036	$1.1961
30	60	$38.66	$31.96	$70.62	$38.66	$27.14	$65.80	$41.54	$33.59	$75.14	$41.54	$27.14	$68.69	$4.52	6.4%	$2.88	4.4%	$1.1769	$1.0967	$1.2523	$1.1448
31	70	$42.52	$37.28	$79.80	$42.52	$31.67	$74.19	$45.90	$39.19	$85.09	$45.90	$31.67	$77.57	$5.29	6.6%	$3.38	4.6%	$1.1400	$1.0598	$1.2156	$1.1081
32	80	$46.38	$42.61	$88.99	$46.38	$36.19	$82.57	$50.26	$44.79	$95.05	$50.26	$36.19	$86.45	$6.06	6.8%	$3.88	4.7%	$1.1124	$1.0322	$1.1881	$1.0806
33	90	$50.24	$47.93	$98.17	$50.24	$40.72	$90.96	$54.62	$50.39	$105.01	$54.62	$40.72	$95.33	$6.83	7.0%	$4.38	4.8%	$1.0908	$1.0106	$1.1668	$1.0592
34	100	$54.10	$53.26	$107.36	$54.10	$45.24	$99.34	$58.97	$55.99	$114.97	$58.97	$45.24	$104.21	$7.61	7.1%	$4.87	4.9%	$1.0736	$0.9934	$1.1497	$1.0421
35	200	$92.70	$106.52	$199.22	$92.70	$90.48	$183.18	$102.56	$111.98	$214.54	$102.56	$90.48	$193.04	$15.32	7.7%	$9.86	5.4%	$0.9961	$0.9159	$1.0727	$0.9652
36																					

37 **Estimated Bill Percentiles**

Line		Use	Present Winter Base Rates	COG / LDAC	TOTAL	Present Summer Base Rates	COG / LDAC	TOTAL	Proposed Winter Base Rates	COG / LDAC	TOTAL	Proposed Summer Base Rates	COG / LDAC	TOTAL	Winter $	%	Summer $	%	Current Winter	Current Summer	Proposed Winter	Proposed Summer
38	Winter - 25%	8	$18.59	$4.26	$22.85				$18.88	$4.48	$23.36				$0.51	2.2%			$2.8561		$2.9198	
39	Winter - 50%	20	$23.22	$10.65	$33.87				$24.11	$11.20	$35.31				$1.44	4.2%			$1.6936		$1.7654	
40	Winter - 75%	30	$27.08	$15.98	$43.06				$28.47	$16.80	$45.26				$2.21	5.1%			$1.4353		$1.5088	
41	Summer - 25%	5				$17.43	$2.26	$19.69				$17.57	$2.26	$19.83			$0.14	0.7%		$3.9384		$3.9667
42	Summer - 50%	11				$19.75	$4.98	$24.72				$20.19	$4.98	$25.16			$0.44	1.8%		$2.2475		$2.2875
43	Summer - 75%	20				$23.22	$9.05	$32.27				$24.11	$9.05	$33.16			$0.89	2.8%		$1.6134		$1.6578

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE R-3 : RESIDENTIAL HEATING

Line	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
1						
2	Cost of Gas	$0.4737	$0.3935	Cost of Gas	$0.5010	$0.3935
3	LDAC	$0.0589	$0.0589	LDAC	$0.0589	$0.0589
4						
5	Customer charge	$15.50		Customer charge	$15.39	
6	Sales rate			Sales rate		
7	First Block Size			First Block Size		
8	Block 1	$0.5678	$0.5678	Block 1	$0.5985	$0.5985
9	Block 2	$0.5678	$0.5678	Block 2	$0.5985	$0.5985
10						
11						

Line		Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13	Use per	Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14	Month (therms)	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																					
16	0	$15.50	$0.00	$15.50	$15.50	$0.00	$15.50	$15.39	$0.00	$15.39	$15.39	$0.00	$15.39	-$0.11	-0.7%	-$0.11	-0.7%	$0.0000	$0.0000	$0.0000	$0.0000
17	10	$21.18	$5.33	$26.50	$21.18	$4.52	$25.70	$21.38	$5.60	$26.98	$21.38	$4.52	$25.90	$0.47	1.8%	$0.20	0.8%	$2.6504	$2.5702	$2.6976	$2.5901
18	25	$29.70	$13.32	$43.01	$29.70	$11.31	$41.01	$30.35	$14.00	$44.35	$30.35	$11.31	$41.66	$1.34	3.1%	$0.66	1.6%	$1.7204	$1.6402	$1.7741	$1.6666
19	50	$43.89	$26.63	$70.52	$43.89	$22.62	$66.51	$45.32	$28.00	$73.31	$45.32	$22.62	$67.94	$2.79	4.0%	$1.43	2.1%	$1.4104	$1.3302	$1.4662	$1.3587
20	75	$58.09	$39.95	$98.03	$58.09	$33.93	$92.02	$60.28	$41.99	$102.27	$60.28	$33.93	$94.21	$4.24	4.3%	$2.19	2.4%	$1.3071	$1.2269	$1.3636	$1.2561
21	100	$72.28	$53.26	$125.54	$72.28	$45.24	$117.52	$75.24	$55.99	$131.23	$75.24	$45.24	$120.48	$5.69	4.5%	$2.96	2.5%	$1.2554	$1.1752	$1.3123	$1.2048
22	125	$86.48	$66.58	$153.05	$86.48	$56.55	$143.03	$90.20	$69.99	$160.19	$90.20	$56.55	$146.75	$7.14	4.7%	$3.72	2.6%	$1.2244	$1.1442	$1.2815	$1.1740
23	150	$100.67	$79.89	$180.56	$100.67	$67.86	$168.53	$105.16	$83.99	$189.15	$105.16	$67.86	$173.02	$8.59	4.8%	$4.49	2.7%	$1.2037	$1.1235	$1.2610	$1.1535
24	175	$114.87	$93.21	$208.07	$114.87	$79.17	$194.04	$120.12	$97.98	$218.11	$120.12	$79.17	$199.29	$10.04	4.8%	$5.26	2.7%	$1.1890	$1.1088	$1.2463	$1.1388
25	200	$129.06	$106.52	$235.58	$129.06	$90.48	$219.54	$135.08	$111.98	$247.07	$135.08	$90.48	$225.56	$11.49	4.9%	$6.02	2.7%	$1.1779	$1.0977	$1.2353	$1.1278
26	225	$143.26	$119.84	$263.09	$143.26	$101.79	$245.05	$150.05	$125.98	$276.03	$150.05	$101.79	$251.84	$12.94	4.9%	$6.79	2.8%	$1.1693	$1.0891	$1.2268	$1.1193
27	250	$157.45	$133.15	$290.60	$157.45	$113.10	$270.55	$165.01	$139.98	$304.98	$165.01	$113.10	$278.11	$14.38	5.0%	$7.56	2.8%	$1.1624	$1.0822	$1.2199	$1.1124
28	275	$171.65	$146.47	$318.11	$171.65	$124.41	$296.06	$179.97	$153.98	$333.94	$179.97	$124.41	$304.38	$15.83	5.0%	$8.32	2.8%	$1.1568	$1.0766	$1.2143	$1.1068
29	300	$185.84	$159.78	$345.62	$185.84	$135.72	$321.56	$194.93	$167.97	$362.90	$194.93	$135.72	$330.65	$17.28	5.0%	$9.09	2.8%	$1.1521	$1.0719	$1.2097	$1.1022
30	350	$214.23	$186.41	$400.64	$214.23	$158.34	$372.57	$224.85	$195.97	$420.82	$224.85	$158.34	$383.19	$20.18	5.0%	$10.62	2.9%	$1.1447	$1.0645	$1.2023	$1.0948
31	400	$242.62	$213.04	$455.66	$242.62	$180.96	$423.58	$254.78	$223.96	$478.74	$254.78	$180.96	$435.74	$23.08	5.1%	$12.16	2.9%	$1.1392	$1.0590	$1.1969	$1.0893
32	450	$271.01	$239.67	$510.68	$271.01	$203.58	$474.59	$284.70	$251.96	$536.66	$284.70	$203.58	$488.28	$25.98	5.1%	$13.69	2.9%	$1.1348	$1.0546	$1.1926	$1.0851
33	500	$299.40	$266.30	$565.70	$299.40	$226.20	$525.60	$314.62	$279.96	$594.58	$314.62	$226.20	$540.82	$28.88	5.1%	$15.22	2.9%	$1.1314	$1.0512	$1.1892	$1.0816
34	750	$441.35	$399.45	$840.80	$441.35	$339.30	$780.65	$464.24	$419.93	$884.17	$464.24	$339.30	$803.54	$43.37	5.2%	$22.89	2.9%	$1.1211	$1.0409	$1.1789	$1.0714
35	1,000	$583.30	$532.60	$1,115.90	$583.30	$452.40	$1,035.70	$613.85	$559.91	$1,173.76	$613.85	$452.40	$1,066.25	$57.86	5.2%	$30.55	2.9%	$1.1159	$1.0357	$1.1738	$1.0662
36																					

37 **Estimated Bill Percentiles**

Line		Use	Present Winter Base Rates	COG / LDAC	TOTAL	Present Summer Base Rates	COG / LDAC	TOTAL	Proposed Winter Base Rates	COG / LDAC	TOTAL	Proposed Summer Base Rates	COG / LDAC	TOTAL	Winter $	%	Summer $	%	Current Winter	Current Summer	Proposed Winter	Proposed Summer
38	Winter - 25%	60	$49.57	$31.96	$81.52				$51.30	$33.59	$84.89				$3.37	4.1%			$1.3587		$1.4149	
39	Winter - 50%	100	$72.28	$53.26	$125.54				$75.24	$55.99	$131.23				$5.69	4.5%			$1.2554		$1.3123	
40	Winter - 75%	175	$114.87	$93.21	$208.07				$120.12	$97.98	$218.11				$10.04	4.8%			$1.1890		$1.2463	
41	Summer - 25%	12				$22.31	$5.43	$27.74				$22.57	$5.43	$28.00			$0.26	0.9%		$2.3119		$2.3336
42	Summer - 50%	20				$26.86	$9.05	$35.90				$27.36	$9.05	$36.41			$0.51	1.4%		$1.7952		$1.8205
43	Summer - 75%	30				$32.53	$13.57	$46.11				$33.35	$13.57	$46.92			$0.81	1.8%		$1.5369		$1.5639

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE R-4 : LOW INCOME RESIDENTIAL HEATING

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
1	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
2	Cost of Gas	$0.4737	$0.3935	Cost of Gas	$0.5010	$0.3935
3	LDAC	$0.0589	$0.0589	LDAC	$0.0589	$0.0589
4						
5	Customer charge	$8.53	$15.50	Customer charge	$8.47	$15.39
6	Sales rate			Sales rate		
7	First Block Size			First Block Size		
8	Block 1	$0.3123	$0.5678	Block 1	$0.3292	$0.5985
9	Block 2	$0.3123	$0.5678	Block 2	$0.3292	$0.5985
10						
11						

Line		Use per Month (therms)	Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13			Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14			Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																						
16		0	$8.53	$0.00	$8.53	$15.50	$0.00	$15.50	$8.47	$0.00	$8.47	$15.39	$0.00	$15.39	-$0.06	-0.8%	-$0.10	-0.7%	$0.0000	$0.0000	$0.0000	$0.0000
17		10	$11.65	$5.33	$16.98	$21.17	$4.52	$25.70	$11.76	$5.60	$17.36	$21.38	$4.52	$25.90	$0.38	2.2%	$0.20	0.8%	$1.6979	$2.5699	$1.7356	$2.5901
18		25	$16.34	$13.32	$29.65	$29.69	$11.31	$41.00	$16.69	$14.00	$30.69	$30.35	$11.31	$41.66	$1.04	3.5%	$0.66	1.6%	$1.1861	$1.6401	$1.2277	$1.6666
19		50	$24.15	$26.63	$50.78	$43.89	$22.62	$66.51	$24.92	$28.00	$52.92	$45.32	$22.62	$67.94	$2.14	4.2%	$1.43	2.1%	$1.0155	$1.3301	$1.0584	$1.3587
20		75	$31.95	$39.95	$71.90	$58.08	$33.93	$92.01	$33.15	$41.99	$75.15	$60.28	$33.93	$94.21	$3.25	4.5%	$2.19	2.4%	$0.9586	$1.2268	$1.0019	$1.2561
21		100	$39.76	$53.26	$93.02	$72.28	$45.24	$117.52	$41.38	$55.99	$97.37	$75.24	$45.24	$120.48	$4.35	4.7%	$2.96	2.5%	$0.9302	$1.1752	$0.9737	$1.2048
22		125	$47.57	$66.58	$114.14	$86.47	$56.55	$143.02	$49.61	$69.99	$119.60	$90.20	$56.55	$146.75	$5.46	4.8%	$3.73	2.6%	$0.9131	$1.1442	$0.9568	$1.1740
23		150	$55.38	$79.89	$135.27	$100.67	$67.86	$168.53	$57.84	$83.99	$141.83	$105.16	$67.86	$173.02	$6.56	4.9%	$4.49	2.7%	$0.9018	$1.1235	$0.9455	$1.1535
24		175	$63.18	$93.21	$156.39	$114.86	$79.17	$194.03	$66.07	$97.98	$164.05	$120.12	$79.17	$199.29	$7.66	4.9%	$5.26	2.7%	$0.8936	$1.1088	$0.9374	$1.1388
25		200	$70.99	$106.52	$177.51	$129.06	$90.48	$219.54	$74.30	$111.98	$186.28	$135.08	$90.48	$225.56	$8.77	4.9%	$6.03	2.7%	$0.8876	$1.0977	$0.9314	$1.1278
26		225	$78.80	$119.84	$198.63	$143.25	$101.79	$245.04	$82.52	$125.98	$208.51	$150.05	$101.79	$251.84	$9.87	5.0%	$6.79	2.8%	$0.8828	$1.0891	$0.9267	$1.1193
27		250	$86.61	$133.15	$219.76	$157.45	$113.10	$270.55	$90.75	$139.98	$230.73	$165.01	$113.10	$278.11	$10.98	5.0%	$7.56	2.8%	$0.8790	$1.0822	$0.9229	$1.1124
28		275	$94.41	$146.47	$240.88	$171.64	$124.41	$296.05	$98.98	$153.98	$252.96	$179.97	$124.41	$304.38	$12.08	5.0%	$8.33	2.8%	$0.8759	$1.0766	$0.9198	$1.1068
29		300	$102.22	$159.78	$262.00	$185.84	$135.72	$321.56	$107.21	$167.97	$275.18	$194.93	$135.72	$330.65	$13.18	5.0%	$9.09	2.8%	$0.8733	$1.0719	$0.9173	$1.1022
30		350	$117.84	$186.41	$304.25	$214.23	$158.34	$372.57	$123.67	$195.97	$319.64	$224.85	$158.34	$383.19	$15.39	5.1%	$10.63	2.9%	$0.8693	$1.0645	$0.9133	$1.0948
31		400	$133.45	$213.04	$346.49	$242.62	$180.96	$423.58	$140.13	$223.96	$364.09	$254.78	$180.96	$435.74	$17.60	5.1%	$12.16	2.9%	$0.8662	$1.0589	$0.9102	$1.0893
32		450	$149.07	$239.67	$388.74	$271.01	$203.58	$474.59	$156.58	$251.96	$408.54	$284.70	$203.58	$488.28	$19.81	5.1%	$13.69	2.9%	$0.8639	$1.0546	$0.9079	$1.0851
33		500	$164.68	$266.30	$430.98	$299.40	$226.20	$525.60	$173.04	$279.96	$453.00	$314.62	$226.20	$540.82	$22.02	5.1%	$15.22	2.9%	$0.8620	$1.0512	$0.9060	$1.0816
34		750	$242.76	$399.45	$642.21	$441.35	$339.30	$780.65	$255.33	$419.93	$675.26	$464.24	$339.30	$803.54	$33.06	5.1%	$22.89	2.9%	$0.8563	$1.0409	$0.9004	$1.0714
35		1,000	$320.83	$532.60	$853.43	$583.30	$452.40	$1,035.70	$337.62	$559.91	$897.53	$613.85	$452.40	$1,066.25	$44.10	5.2%	$30.55	2.9%	$0.8534	$1.0357	$0.8975	$1.0662
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	70	$30.39	$37.28	$67.67				$31.51	$39.19	$70.70				$3.03	4.5%			$0.9668		$1.0100	
39	Winter - 50%	100	$39.76	$53.26	$93.02				$41.38	$55.99	$97.37				$4.35	4.7%			$0.9302		$0.9737	
40	Winter - 75%	150	$55.38	$79.89	$135.27				$57.84	$83.99	$141.83				$6.56	4.9%			$0.9018		$0.9455	
41	Summer - 25%	14				$23.45	$6.33	$29.78				$23.77	$6.33	$30.10			$0.32	1.1%		$2.1271		$2.1503
42	Summer - 50%	25				$29.69	$11.31	$41.00				$30.35	$11.31	$41.66			$0.66	1.6%		$1.6401		$1.6666
43	Summer - 75%	40				$38.21	$18.10	$56.30				$39.33	$18.10	$57.43			$1.12	2.0%		$1.4076		$1.4357

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-41 : COMMERCIAL/INDUSTRIAL - LOW ANNUAL USE, HIGH WINTER USE

Present Rates	Winter	Summer
Cost of Gas	$0.4724	$0.3886
LDAC	$0.0555	$0.0555
Customer charge	$57.46	
Sales rate		
First Block Size	100	20
Block 1	$0.4711	$0.4711
Block 2	$0.3165	$0.3165

Proposed Rates	Winter	Summer
Cost of Gas	$0.4997	$0.3886
LDAC	$0.0555	$0.0555
Customer charge	$59.55	
Sales rate		
First Block Size	100	20
Block 1	$0.4848	$0.4848
Block 2	$0.3309	$0.3309

	Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
Use per	Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
Month (therms)	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
0	$57	$0	$57	$57	$0	$57	$60	$0	$60	$60	$0	$60	$2.09	3.6%	$2.09	3.6%	$0.0000	$0.0000	$0.0000	$0.0000
10	$62	$5	$67	$62	$4	$67	$64	$6	$70	$64	$4	$69	$2.50	3.7%	$2.22	3.3%	$6.7450	$6.6612	$6.9945	$6.8834
25	$69	$13	$82	$68	$11	$80	$72	$14	$86	$71	$11	$82	$3.11	3.8%	$2.43	3.1%	$3.2974	$3.1827	$3.4218	$3.2799
50	$81	$26	$107	$76	$22	$99	$84	$28	$112	$79	$22	$101	$4.13	3.8%	$2.79	2.8%	$2.1482	$1.9716	$2.2309	$2.0275
75	$93	$40	$132	$84	$33	$118	$96	$42	$138	$87	$33	$121	$5.16	3.9%	$3.15	2.7%	$1.7651	$1.5680	$1.8339	$1.6100
100	$105	$53	$157	$92	$44	$137	$108	$56	$164	$96	$44	$140	$6.18	3.9%	$3.51	2.6%	$1.5736	$1.3661	$1.6354	$1.4012
150	$120	$79	$200	$108	$67	$175	$125	$83	$208	$112	$67	$179	$8.27	4.1%	$4.23	2.4%	$1.3305	$1.1643	$1.3857	$1.1925
200	$136	$106	$242	$124	$89	$213	$141	$111	$252	$129	$89	$218	$10.35	4.3%	$4.95	2.3%	$1.2090	$1.0634	$1.2608	$1.0881
250	$152	$132	$284	$140	$111	$251	$158	$139	$296	$145	$111	$256	$12.44	4.4%	$5.67	2.3%	$1.1361	$1.0028	$1.1858	$1.0255
300	$168	$158	$326	$156	$133	$289	$174	$167	$341	$162	$133	$295	$14.53	4.5%	$6.39	2.2%	$1.0875	$0.9624	$1.1359	$0.9838
350	$184	$185	$368	$171	$155	$327	$191	$194	$385	$178	$155	$334	$16.61	4.5%	$7.12	2.2%	$1.0527	$0.9336	$1.1002	$0.9539
400	$200	$211	$411	$187	$178	$365	$207	$222	$429	$195	$178	$373	$18.70	4.6%	$7.84	2.1%	$1.0267	$0.9120	$1.0734	$0.9316
500	$231	$264	$495	$219	$222	$441	$240	$278	$518	$228	$222	$450	$22.87	4.6%	$9.28	2.1%	$0.9902	$0.8817	$1.0360	$0.9003
600	$263	$317	$580	$250	$266	$517	$273	$333	$607	$261	$266	$528	$27.05	4.7%	$10.72	2.1%	$0.9659	$0.8615	$1.0110	$0.8794
700	$294	$370	$664	$282	$311	$593	$307	$389	$695	$294	$311	$605	$31.22	4.7%	$12.16	2.1%	$0.9486	$0.8471	$0.9932	$0.8645
800	$326	$422	$748	$314	$355	$669	$340	$444	$784	$327	$355	$683	$35.39	4.7%	$13.60	2.0%	$0.9356	$0.8363	$0.9798	$0.8533
900	$358	$475	$833	$345	$400	$745	$373	$500	$872	$360	$400	$760	$39.56	4.8%	$15.04	2.0%	$0.9254	$0.8279	$0.9694	$0.8446
1,000	$389	$528	$917	$377	$444	$821	$406	$555	$961	$394	$444	$838	$43.74	4.8%	$16.48	2.0%	$0.9173	$0.8212	$0.9611	$0.8376
1,250	$469	$660	$1,128	$456	$555	$1,011	$489	$694	$1,183	$476	$555	$1,031	$54.17	4.8%	$20.09	2.0%	$0.9027	$0.8090	$0.9461	$0.8251
1,500	$548	$792	$1,340	$535	$666	$1,201	$571	$833	$1,404	$559	$666	$1,225	$64.60	4.8%	$23.69	2.0%	$0.8930	$0.8010	$0.9361	$0.8168

Estimated Bill Percentiles

	Use	Present Winter Base Rates	Present Winter COG / LDAC	Present Winter TOTAL	Present Summer Base Rates	Present Summer COG / LDAC	Present Summer TOTAL	Proposed Winter Base Rates	Proposed Winter COG / LDAC	Proposed Winter TOTAL	Proposed Summer Base Rates	Proposed Summer COG / LDAC	Proposed Summer TOTAL	Winter $	Winter %	Summer $	Summer %	Current Winter	Current Summer	Proposed Winter	Proposed Summer
Winter - 25%	70	$90	$37	$127				$93	$39	$132				$4.95	3.9%			$1.8199		$1.8906	
Winter - 50%	200	$136	$106	$242				$141	$111	$252				$10.35	4.3%			$1.2090		$1.2608	
Winter - 75%	500	$231	$264	$495				$240	$278	$518				$22.87	4.6%			$0.9902		$1.0360	
Summer - 25%	0				$57	$0	$57				$60	$0	$60			$2.09	3.6%		$0.0000		$0.0000
Summer - 50%	8				$61	$4	$65				$63	$4	$67			$2.19	3.4%		$8.0977		$8.3720
Summer - 75%	45				$75	$20	$95				$78	$20	$97			$2.72	2.9%		$2.1062		$2.1666

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-42 : COMMERCIAL/INDUSTRIAL - MEDIUM ANNUAL USE, HIGH WINTER USE

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
1	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
2	Cost of Gas	$0.4724	$0.3886	Cost of Gas	$0.4997	$0.3886
3	LDAC	$0.0555	$0.0555	LDAC	$0.0555	$0.0555
4						
5	Customer charge	$172.39		Customer charge	$178.61	
6	Sales rate			Sales rate		
7	First Block Size	1000	400	First Block Size	1000	400
8	Block 1	$0.4284	$0.4284	Block 1	$0.4409	$0.4409
9	Block 2	$0.2855	$0.2855	Block 2	$0.2988	$0.2988

Line		Use per Month (therms)	Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13			Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14			Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																						
16		0	$172	$0	$172	$172	$0	$172	$179	$0	$179	$179	$0	$179	$6.22	3.6%	$6.22	3.6%	$0.0000	$0.0000	$0.0000	$0.0000
17		10	$177	$5	$182	$177	$4	$181	$183	$6	$189	$183	$4	$187	$6.62	3.6%	$6.34	3.5%	$18.1953	$18.1115	$18.8571	$18.7460
18		25	$183	$13	$196	$183	$11	$194	$190	$14	$204	$190	$11	$201	$7.22	3.7%	$6.53	3.4%	$7.8519	$7.7681	$8.1405	$8.0294
19		50	$194	$26	$220	$194	$22	$216	$201	$28	$228	$201	$22	$223	$8.21	3.7%	$6.85	3.2%	$4.4041	$4.3203	$4.5683	$4.4572
20		75	$205	$40	$244	$205	$33	$238	$212	$42	$253	$212	$33	$245	$9.21	3.8%	$7.16	3.0%	$3.2548	$3.1710	$3.3776	$3.2665
21		100	$215	$53	$268	$215	$44	$260	$223	$56	$278	$223	$44	$267	$10.20	3.8%	$7.47	2.9%	$2.6802	$2.5964	$2.7822	$2.6711
22		150	$237	$79	$316	$237	$67	$303	$245	$83	$328	$245	$67	$311	$12.19	3.9%	$8.10	2.7%	$2.1056	$2.0218	$2.1868	$2.0757
23		200	$258	$106	$364	$258	$89	$347	$267	$111	$378	$267	$89	$356	$14.18	3.9%	$8.72	2.5%	$1.8183	$1.7345	$1.8892	$1.7781
24		250	$279	$132	$411	$279	$111	$391	$289	$139	$428	$289	$111	$400	$16.17	3.9%	$9.35	2.4%	$1.6459	$1.5621	$1.7106	$1.5994
25		300	$301	$158	$459	$301	$133	$434	$311	$167	$477	$311	$133	$444	$18.17	4.0%	$9.97	2.3%	$1.5309	$1.4471	$1.5915	$1.4804
26		350	$322	$185	$507	$322	$155	$478	$333	$194	$527	$333	$155	$488	$20.16	4.0%	$10.60	2.2%	$1.4488	$1.3650	$1.5064	$1.3953
27		400	$344	$211	$555	$344	$178	$521	$355	$222	$577	$355	$178	$533	$22.15	4.0%	$11.22	2.2%	$1.3873	$1.3035	$1.4426	$1.3315
28		500	$387	$264	$651	$372	$222	$594	$399	$278	$677	$385	$222	$607	$26.13	4.0%	$12.55	2.1%	$1.3011	$1.1887	$1.3533	$1.2138
29		750	$494	$396	$890	$444	$333	$777	$509	$416	$926	$460	$333	$793	$36.08	4.1%	$15.87	2.0%	$1.1862	$1.0357	$1.2343	$1.0568
30		1,000	$601	$528	$1,129	$515	$444	$959	$620	$555	$1,175	$534	$444	$978	$46.04	4.1%	$19.20	2.0%	$1.1287	$0.9592	$1.1747	$0.9783
31		1,500	$744	$792	$1,535	$658	$666	$1,324	$769	$833	$1,602	$684	$666	$1,350	$66.34	4.3%	$25.84	2.0%	$1.0236	$0.8826	$1.0678	$0.8999
32		2,000	$886	$1,056	$1,942	$801	$888	$1,689	$918	$1,110	$2,029	$833	$888	$1,721	$86.64	4.5%	$32.48	1.9%	$0.9710	$0.8444	$1.0144	$0.8606
33		3,000	$1,172	$1,584	$2,755	$1,086	$1,332	$2,418	$1,217	$1,666	$2,883	$1,132	$1,332	$2,464	$127.24	4.6%	$45.77	1.9%	$0.9185	$0.8061	$0.9609	$0.8214
34		4,000	$1,457	$2,112	$3,569	$1,372	$1,776	$3,148	$1,516	$2,221	$3,737	$1,431	$1,776	$3,207	$167.84	4.7%	$59.06	1.9%	$0.8922	$0.7870	$0.9342	$0.8018
35		5,000	$1,743	$2,640	$4,382	$1,657	$2,221	$3,878	$1,815	$2,776	$4,591	$1,729	$2,221	$3,950	$208.44	4.8%	$72.35	1.9%	$0.8765	$0.7755	$0.9181	$0.7900
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	1,300	$686	$686	$1,373				$709	$722	$1,431				$58.22	4.2%			$1.0559		$1.1007	
39	Winter - 50%	2,000	$886	$1,056	$1,942				$918	$1,110	$2,029				$86.64	4.5%			$0.9710		$1.0144	
40	Winter - 75%	3,500	$1,315	$1,848	$3,162				$1,366	$1,943	$3,310				$147.54	4.7%			$0.9035		$0.9456	
41	Summer - 25%	45				$192	$20	$212				$198	$20	$218			$6.78	3.2%		$4.7034		$4.8541
42	Summer - 50%	350				$322	$155	$478				$333	$155	$488			$10.60	2.2%		$1.3650		$1.3953
43	Summer - 75%	750				$444	$333	$777				$460	$333	$793			$15.87	2.0%		$1.0357		$1.0568

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-43 : COMMERCIAL/INDUSTRIAL - HIGH ANNUAL USE, HIGH WINTER USE

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
1	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
2	Cost of Gas	$0.4724	$0.3886	Cost of Gas	$0.4997	$0.3886
3	LDAC	$0.0555	$0.0555	LDAC	$0.0555	$0.0555
4						
5	Customer charge	$739.83		Customer charge	$765.51	
6	Sales rate			Sales rate		
7	First Block Size			First Block Size		
8	Block 1	$0.2633	$0.1204	Block 1	$0.2717	$0.1295
9	Block 2	$0.2633	$0.1204	Block 2	$0.2717	$0.1295

Line		Use per Month (therms)	Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
12			Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
13-14			Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																						
16		200	$792	$106	$898	$764	$89	$853	$820	$111	$931	$791	$89	$880	$32.82	3.7%	$27.50	3.2%	$4.4904	$4.2637	$4.6544	$4.4011
17		500	$871	$264	$1,135	$800	$222	$1,022	$901	$278	$1,179	$830	$222	$1,052	$43.53	3.8%	$30.23	3.0%	$2.2709	$2.0442	$2.3579	$2.1046
18		1,000	$1,003	$528	$1,531	$860	$444	$1,304	$1,037	$555	$1,592	$895	$444	$1,339	$61.38	4.0%	$34.79	2.7%	$1.5310	$1.3043	$1.5924	$1.3391
19		1,250	$1,069	$660	$1,729	$890	$555	$1,445	$1,105	$694	$1,799	$927	$555	$1,483	$70.31	4.1%	$37.06	2.6%	$1.3831	$1.1564	$1.4393	$1.1860
20		1,500	$1,135	$792	$1,927	$920	$666	$1,587	$1,173	$833	$2,006	$960	$666	$1,626	$79.24	4.1%	$39.34	2.5%	$1.2844	$1.0577	$1.3372	$1.0839
21		1,750	$1,201	$924	$2,124	$951	$777	$1,728	$1,241	$972	$2,213	$992	$777	$1,769	$88.16	4.1%	$41.62	2.4%	$1.2140	$0.9873	$1.2643	$1.0110
22		2,000	$1,266	$1,056	$2,322	$981	$888	$1,869	$1,309	$1,110	$2,419	$1,025	$888	$1,913	$97.09	4.2%	$43.90	2.3%	$1.1611	$0.9344	$1.2097	$0.9564
23		2,500	$1,398	$1,320	$2,718	$1,041	$1,110	$2,151	$1,445	$1,388	$2,833	$1,089	$1,110	$2,200	$114.94	4.2%	$48.45	2.3%	$1.0871	$0.8604	$1.1331	$0.8798
24		3,000	$1,530	$1,584	$3,113	$1,101	$1,332	$2,433	$1,581	$1,666	$3,246	$1,154	$1,332	$2,486	$132.79	4.3%	$53.01	2.2%	$1.0378	$0.8111	$1.0821	$0.8288
25		3,500	$1,661	$1,848	$3,509	$1,161	$1,554	$2,716	$1,716	$1,943	$3,660	$1,219	$1,554	$2,773	$150.65	4.3%	$57.56	2.1%	$1.0026	$0.7759	$1.0456	$0.7923
26		4,000	$1,793	$2,112	$3,905	$1,221	$1,776	$2,998	$1,852	$2,221	$4,073	$1,284	$1,776	$3,060	$168.50	4.3%	$62.12	2.1%	$0.9762	$0.7495	$1.0183	$0.7650
27		4,500	$1,925	$2,376	$4,300	$1,282	$1,998	$3,280	$1,988	$2,498	$4,487	$1,348	$1,998	$3,347	$186.35	4.3%	$66.67	2.0%	$0.9556	$0.7289	$0.9970	$0.7437
28		5,000	$2,056	$2,640	$4,696	$1,342	$2,221	$3,562	$2,124	$2,776	$4,900	$1,413	$2,221	$3,634	$204.20	4.3%	$71.23	2.0%	$0.9392	$0.7125	$0.9800	$0.7267
29		6,000	$2,320	$3,167	$5,487	$1,462	$2,665	$4,127	$2,396	$3,331	$5,727	$1,543	$2,665	$4,207	$239.91	4.4%	$80.34	1.9%	$0.9145	$0.6878	$0.9545	$0.7012
30		7,000	$2,583	$3,695	$6,278	$1,583	$3,109	$4,691	$2,667	$3,886	$6,554	$1,672	$3,109	$4,781	$275.61	4.4%	$89.45	1.9%	$0.8969	$0.6702	$0.9363	$0.6830
31		8,000	$2,846	$4,223	$7,069	$1,703	$3,553	$5,256	$2,939	$4,442	$7,381	$1,802	$3,553	$5,354	$311.32	4.4%	$98.55	1.9%	$0.8837	$0.6570	$0.9226	$0.6693
32		9,000	$3,110	$4,751	$7,861	$1,823	$3,997	$5,820	$3,211	$4,997	$8,208	$1,931	$3,997	$5,928	$347.02	4.4%	$107.66	1.8%	$0.8734	$0.6467	$0.9120	$0.6587
33		10,000	$3,373	$5,279	$8,652	$1,944	$4,441	$6,385	$3,482	$5,552	$9,035	$2,061	$4,441	$6,502	$382.73	4.4%	$116.77	1.8%	$0.8652	$0.6385	$0.9035	$0.6502
34		15,000	$4,689	$7,919	$12,608	$2,546	$6,662	$9,207	$4,841	$8,328	$13,169	$2,708	$6,662	$9,370	$561.25	4.5%	$162.32	1.8%	$0.8405	$0.6138	$0.8779	$0.6246
35		20,000	$6,006	$10,558	$16,564	$3,148	$8,882	$12,030	$6,199	$11,104	$17,304	$3,356	$8,882	$12,238	$739.78	4.5%	$207.87	1.7%	$0.8282	$0.6015	$0.8652	$0.6119
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	9,000	$3,110	$4,751	$7,861				$3,211	$4,997	$8,208				$347.02	4.4%			$0.8734		$0.9120	
39	Winter - 50%	15,000	$4,689	$7,919	$12,608				$4,841	$8,328	$13,169				$561.25	4.5%			$0.8405		$0.8779	
40	Winter - 75%	25,000	$7,322	$13,198	$20,520				$7,558	$13,880	$21,438				$918.30	4.5%			$0.8208		$0.8575	
41	Summer - 25%	450				$794	$200	$994				$824	$200	$1,024			$29.78	3.0%		$2.2086		$2.2747
42	Summer - 50%	3,500				$1,161	$1,554	$2,716				$1,219	$1,554	$2,773			$57.56	2.1%		$0.7759		$0.7923
43	Summer - 75%	10,000				$1,944	$4,441	$6,385				$2,061	$4,441	$6,502			$116.77	1.8%		$0.6385		$0.6502

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-51 : COMMERCIAL/INDUSTRIAL - LOW ANNUAL USE, LOW WINTER USE

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
1	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
2	Cost of Gas	$0.4792	$0.3999	Cost of Gas	$0.5065	$0.3999
3	LDAC	$0.0555	$0.0555	LDAC	$0.0555	$0.0555
4						
5	Customer charge	$57.46		Customer charge	$59.57	
6	Sales rate			Sales rate		
7	First Block Size	100	100	First Block Size	100	100
8	Block 1	$0.2839	$0.2839	Block 1	$0.2920	$0.2920
9	Block 2	$0.1846	$0.1846	Block 2	$0.1934	$0.1934
10						
11						

Line		Use per Month (therms)	Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13			Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14			Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																						
16		0	$57	$0	$57	$57	$0	$57	$60	$0	$60	$60	$0	$60	$2.11	3.7%	$2.11	3.7%	$0.0000	$0.0000	$0.0000	$0.0000
17		10	$60	$5	$66	$60	$5	$65	$62	$6	$68	$62	$5	$67	$2.46	3.8%	$2.19	3.4%	$6.5646	$6.4853	$6.8109	$6.7043
18		25	$65	$13	$78	$65	$11	$76	$67	$14	$81	$67	$11	$78	$2.99	3.8%	$2.31	3.0%	$3.1170	$3.0377	$3.2368	$3.1302
19		50	$72	$27	$98	$72	$23	$94	$74	$28	$102	$74	$23	$97	$3.88	3.9%	$2.51	2.7%	$1.9678	$1.8885	$2.0454	$1.9388
20		75	$79	$40	$119	$79	$34	$113	$81	$42	$124	$81	$34	$116	$4.76	4.0%	$2.72	2.4%	$1.5847	$1.5054	$1.6482	$1.5416
21		100	$86	$53	$139	$86	$46	$131	$89	$56	$145	$89	$46	$134	$5.65	4.1%	$2.92	2.2%	$1.3932	$1.3139	$1.4497	$1.3431
22		150	$95	$80	$175	$95	$68	$163	$98	$84	$183	$98	$68	$167	$7.45	4.3%	$3.36	2.1%	$1.1686	$1.0893	$1.2183	$1.1116
23		200	$104	$107	$211	$104	$91	$195	$108	$112	$221	$108	$91	$199	$9.26	4.4%	$3.79	1.9%	$1.0563	$0.9770	$1.1025	$0.9959
24		250	$114	$134	$247	$114	$114	$227	$118	$141	$258	$118	$114	$232	$11.06	4.5%	$4.23	1.9%	$0.9889	$0.9096	$1.0331	$0.9265
25		300	$123	$160	$283	$123	$137	$259	$127	$169	$296	$127	$137	$264	$12.87	4.5%	$4.67	1.8%	$0.9439	$0.8646	$0.9868	$0.8802
26		350	$132	$187	$319	$132	$159	$291	$137	$197	$334	$137	$159	$297	$14.67	4.6%	$5.11	1.8%	$0.9118	$0.8325	$0.9538	$0.8471
27		400	$141	$214	$355	$141	$182	$323	$147	$225	$372	$147	$182	$329	$16.47	4.6%	$5.55	1.7%	$0.8878	$0.8085	$0.9290	$0.8223
28		500	$160	$267	$427	$160	$228	$387	$166	$281	$447	$166	$228	$394	$20.08	4.7%	$6.43	1.7%	$0.8541	$0.7748	$0.8942	$0.7876
29		600	$178	$321	$499	$178	$273	$451	$185	$337	$523	$185	$273	$459	$23.69	4.7%	$7.30	1.6%	$0.8316	$0.7523	$0.8711	$0.7645
30		700	$197	$374	$571	$197	$319	$515	$205	$393	$598	$205	$319	$524	$27.30	4.8%	$8.18	1.6%	$0.8156	$0.7363	$0.8546	$0.7480
31		800	$215	$428	$643	$215	$364	$579	$224	$450	$674	$224	$364	$588	$30.91	4.8%	$9.06	1.6%	$0.8035	$0.7242	$0.8422	$0.7356
32		900	$234	$481	$715	$234	$410	$643	$243	$506	$749	$243	$410	$653	$34.52	4.8%	$9.94	1.5%	$0.7942	$0.7149	$0.8325	$0.7259
33		1,000	$252	$535	$787	$252	$455	$707	$263	$562	$825	$263	$455	$718	$38.13	4.8%	$10.81	1.5%	$0.7867	$0.7074	$0.8248	$0.7182
34		1,250	$298	$668	$967	$298	$569	$867	$311	$703	$1,014	$311	$569	$880	$47.15	4.9%	$13.01	1.5%	$0.7732	$0.6939	$0.8109	$0.7043
35		1,500	$344	$802	$1,146	$344	$683	$1,027	$359	$843	$1,203	$359	$683	$1,043	$56.17	4.9%	$15.20	1.5%	$0.7642	$0.6849	$0.8017	$0.6951
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	45	$70	$24	$94				$73	$25	$98				$3.70	3.9%			$2.0955		$2.1778	
39	Winter - 50%	175	$100	$94	$193				$103	$98	$202				$8.35	4.3%			$1.1044		$1.1521	
40	Winter - 75%	450	$150	$241	$391				$156	$253	$409				$18.28	4.7%			$0.8691		$0.9097	
41	Summer - 25%	6				$59	$3	$62				$61	$3	$64			$2.16	3.5%		$10.3160		$10.6756
42	Summer - 50%	60				$74	$27	$102				$77	$27	$104			$2.59	2.5%		$1.6970		$1.7402
43	Summer - 75%	250				$114	$114	$227				$118	$114	$232			$4.23	1.9%		$0.9096		$0.9265

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-52 : COMMERCIAL/INDUSTRIAL - MEDIUM ANNUAL USE, LOW WINTER USE

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
2	Cost of Gas	$0.4792	$0.3999	Cost of Gas	$0.5065	$0.3999
3	LDAC	$0.0555	$0.0555	LDAC	$0.0555	$0.0555
4						
5	Customer charge	$172.39		Customer charge	$178.49	
6	Sales rate			Sales rate		
7	First Block Size	1000	1000	First Block Size	1000	1000
8	Block 1	$0.2439	$0.1767	Block 1	$0.2515	$0.1846
9	Block 2	$0.1624	$0.1004	Block 2	$0.1704	$0.1087
10						
11						

Line		Use per Month (therms)	Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13			Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14			Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																						
16		200	$221	$107	$328	$208	$91	$299	$229	$112	$341	$215	$91	$307	$13.10	4.0%	$7.69	2.6%	$1.6406	$1.4941	$1.7060	$1.5325
17		300	$246	$160	$406	$225	$137	$362	$254	$169	$423	$234	$137	$371	$16.59	4.1%	$8.49	2.3%	$1.3532	$1.2067	$1.4085	$1.2350
18		400	$270	$214	$484	$243	$182	$425	$279	$225	$504	$252	$182	$435	$20.09	4.2%	$9.28	2.2%	$1.2096	$1.0631	$1.2598	$1.0863
19		500	$294	$267	$562	$261	$228	$488	$304	$281	$585	$271	$228	$499	$23.58	4.2%	$10.07	2.1%	$1.1234	$0.9769	$1.1705	$0.9970
20		600	$319	$321	$640	$278	$273	$552	$329	$337	$667	$289	$273	$563	$27.08	4.2%	$10.87	2.0%	$1.0659	$0.9194	$1.1110	$0.9375
21		700	$343	$374	$717	$296	$319	$615	$355	$393	$748	$308	$319	$627	$30.57	4.3%	$11.66	1.9%	$1.0249	$0.8784	$1.0685	$0.8950
22		800	$368	$428	$795	$314	$364	$678	$380	$450	$829	$326	$364	$691	$34.07	4.3%	$12.45	1.8%	$0.9941	$0.8476	$1.0367	$0.8632
23		900	$392	$481	$873	$331	$410	$741	$405	$506	$911	$345	$410	$755	$37.56	4.3%	$13.25	1.8%	$0.9701	$0.8236	$1.0119	$0.8384
24		1,000	$416	$535	$951	$349	$455	$804	$430	$562	$992	$363	$455	$819	$41.06	4.3%	$14.04	1.7%	$0.9510	$0.8045	$0.9921	$0.8185
25		1,100	$433	$588	$1,021	$359	$501	$860	$447	$618	$1,065	$374	$501	$875	$44.59	4.4%	$14.87	1.7%	$0.9279	$0.7819	$0.9684	$0.7954
26		1,200	$449	$642	$1,090	$369	$546	$916	$464	$674	$1,139	$385	$546	$931	$48.12	4.4%	$15.69	1.7%	$0.9087	$0.7630	$0.9488	$0.7761
27		1,300	$465	$695	$1,160	$379	$592	$971	$481	$731	$1,212	$396	$592	$988	$51.65	4.5%	$16.52	1.7%	$0.8924	$0.7471	$0.9321	$0.7598
28		1,400	$481	$749	$1,230	$389	$638	$1,027	$498	$787	$1,285	$407	$638	$1,044	$55.18	4.5%	$17.35	1.7%	$0.8785	$0.7334	$0.9179	$0.7458
29		1,500	$497	$802	$1,300	$399	$683	$1,082	$515	$843	$1,358	$417	$683	$1,101	$58.71	4.5%	$18.17	1.7%	$0.8664	$0.7216	$0.9055	$0.7337
30		1,750	$538	$936	$1,474	$424	$797	$1,221	$558	$984	$1,541	$445	$797	$1,242	$67.54	4.6%	$20.24	1.7%	$0.8422	$0.6979	$0.8808	$0.7095
31		2,000	$579	$1,069	$1,648	$449	$911	$1,360	$600	$1,124	$1,724	$472	$911	$1,383	$76.37	4.6%	$22.31	1.6%	$0.8240	$0.6801	$0.8622	$0.6913
32		2,500	$660	$1,337	$1,997	$500	$1,139	$1,638	$686	$1,405	$2,091	$526	$1,139	$1,665	$94.02	4.7%	$26.44	1.6%	$0.7987	$0.6553	$0.8363	$0.6659
33		3,000	$741	$1,604	$2,345	$550	$1,366	$1,916	$771	$1,686	$2,457	$580	$1,366	$1,947	$111.68	4.8%	$30.57	1.6%	$0.7817	$0.6387	$0.8190	$0.6489
34		4,000	$903	$2,139	$3,042	$650	$1,822	$2,472	$941	$2,248	$3,189	$689	$1,822	$2,511	$146.99	4.8%	$38.84	1.6%	$0.7606	$0.6180	$0.7973	$0.6277
35		5,000	$1,066	$2,674	$3,739	$751	$2,277	$3,028	$1,112	$2,810	$3,922	$798	$2,277	$3,075	$182.30	4.9%	$47.11	1.6%	$0.7479	$0.6055	$0.7843	$0.6150
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	1,040	$423	$556	$979				$437	$584	$1,021				$42.47	4.3%			$0.9412		$0.9821	
39	Winter - 50%	2,000	$579	$1,069	$1,648				$600	$1,124	$1,724				$76.37	4.6%			$0.8240		$0.8622	
40	Winter - 75%	3,500	$822	$1,871	$2,694				$856	$1,967	$2,823				$129.33	4.8%			$0.7696		$0.8066	
41	Summer - 25%	700				$296	$319	$615				$308	$319	$627			$11.66	1.9%		$0.8784		$0.8950
42	Summer - 50%	1,040				$353	$474	$827				$367	$474	$841			$14.37	1.7%		$0.7949		$0.8087
43	Summer - 75%	2,000				$449	$911	$1,360				$472	$911	$1,383			$22.31	1.6%		$0.6801		$0.6913

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-53 : COMMERCIAL/INDUSTRIAL - HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90%

Line	Present Rates	Winter	Summer	Proposed Rates	Winter	Summer
1	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
2	Cost of Gas	$0.4792	$0.3999	Cost of Gas	$0.5065	$0.3999
3	LDAC	$0.0555	$0.0555	LDAC	$0.0555	$0.0555
4						
5	Customer charge	$761.39		Customer charge	$788.87	
6	Sales rate			Sales rate		
7	First Block Size			First Block Size		
8	Block 1	$0.1705	$0.0818	Block 1	$0.1758	$0.0875
9	Block 2	$0.1705	$0.0818	Block 2	$0.1758	$0.0875

Line		Use per Month (therms)	Present Winter Base Rates	Present Winter COG / LDAC	Present Winter TOTAL	Present Summer Base Rates	Present Summer COG / LDAC	Present Summer TOTAL	Proposed Winter Base Rates	Proposed Winter COG / LDAC	Proposed Winter TOTAL	Proposed Summer Base Rates	Proposed Summer COG / LDAC	Proposed Summer TOTAL	Change Winter $	Change Winter %	Change Summer $	Change Summer %	Unit Costs Current Winter	Unit Costs Current Summer	Unit Costs Proposed Winter	Unit Costs Proposed Summer
16		1,000	$932	$535	$1,467	$843	$455	$1,299	$965	$562	$1,527	$876	$455	$1,332	$60.13	4.1%	$33.21	2.6%	$1.4666	$1.2986	$1.5267	$1.3318
17		2,500	$1,188	$1,337	$2,524	$966	$1,139	$2,104	$1,228	$1,405	$2,633	$1,008	$1,139	$2,146	$109.09	4.3%	$41.79	2.0%	$1.0098	$0.8418	$1.0534	$0.8585
18		5,000	$1,614	$2,674	$4,287	$1,170	$2,277	$3,447	$1,668	$2,810	$4,478	$1,226	$2,277	$3,503	$190.70	4.4%	$56.10	1.6%	$0.8575	$0.6895	$0.8956	$0.7007
19		7,500	$2,040	$4,010	$6,050	$1,375	$3,416	$4,790	$2,108	$4,215	$6,323	$1,445	$3,416	$4,861	$272.31	4.5%	$70.41	1.5%	$0.8067	$0.6387	$0.8430	$0.6481
20		10,000	$2,466	$5,347	$7,813	$1,579	$4,554	$6,133	$2,547	$5,620	$8,167	$1,664	$4,554	$6,218	$353.91	4.5%	$84.71	1.4%	$0.7813	$0.6133	$0.8167	$0.6218
21		12,500	$2,893	$6,684	$9,576	$1,784	$5,693	$7,476	$2,987	$7,025	$10,012	$1,883	$5,693	$7,575	$435.52	4.5%	$99.02	1.3%	$0.7661	$0.5981	$0.8010	$0.6060
22		15,000	$3,319	$8,021	$11,339	$1,988	$6,831	$8,819	$3,426	$8,430	$11,857	$2,102	$6,831	$8,933	$517.13	4.6%	$113.33	1.3%	$0.7560	$0.5880	$0.7904	$0.5955
23		20,000	$4,171	$10,694	$14,865	$2,397	$9,108	$11,505	$4,305	$11,240	$15,546	$2,539	$9,108	$11,647	$680.35	4.6%	$141.95	1.2%	$0.7433	$0.5753	$0.7773	$0.5824
24		25,000	$5,024	$13,368	$18,391	$2,806	$11,385	$14,191	$5,185	$14,050	$19,235	$2,977	$11,385	$14,362	$843.56	4.6%	$170.56	1.2%	$0.7357	$0.5677	$0.7694	$0.5745
25		30,000	$5,876	$16,041	$21,917	$3,215	$13,662	$16,877	$6,064	$16,860	$22,924	$3,415	$13,662	$17,077	$1,006.78	4.6%	$199.18	1.2%	$0.7306	$0.5626	$0.7641	$0.5692
26		35,000	$6,729	$18,715	$25,443	$3,624	$15,939	$19,563	$6,943	$19,670	$26,613	$3,852	$15,939	$19,791	$1,170.00	4.6%	$227.79	1.2%	$0.7270	$0.5590	$0.7604	$0.5655
27		40,000	$7,581	$21,388	$28,969	$4,033	$18,216	$22,249	$7,822	$22,480	$30,303	$4,290	$18,216	$22,506	$1,333.21	4.6%	$256.41	1.2%	$0.7242	$0.5562	$0.7576	$0.5626
28		45,000	$8,434	$24,062	$32,495	$4,442	$20,493	$24,935	$8,701	$25,291	$33,992	$4,727	$20,493	$25,220	$1,496.43	4.6%	$285.03	1.1%	$0.7221	$0.5541	$0.7554	$0.5605
29		50,000	$9,286	$26,735	$36,021	$4,851	$22,770	$27,621	$9,580	$28,101	$37,681	$5,165	$22,770	$27,935	$1,659.65	4.6%	$313.64	1.1%	$0.7204	$0.5524	$0.7536	$0.5587
30		55,000	$10,139	$29,409	$39,547	$5,260	$25,047	$30,307	$10,460	$30,911	$41,370	$5,603	$25,047	$30,650	$1,822.86	4.6%	$342.26	1.1%	$0.7190	$0.5510	$0.7522	$0.5573
31		60,000	$10,991	$32,082	$43,073	$5,669	$27,324	$32,993	$11,339	$33,721	$45,059	$6,040	$27,324	$33,364	$1,986.08	4.6%	$370.88	1.1%	$0.7179	$0.5499	$0.7510	$0.5561
32		75,000	$13,549	$40,103	$53,651	$6,896	$34,155	$41,051	$13,976	$42,151	$56,127	$7,353	$34,155	$41,508	$2,475.73	4.6%	$456.72	1.1%	$0.7154	$0.5474	$0.7484	$0.5534
33		100,000	$17,811	$53,470	$71,281	$8,941	$45,540	$54,481	$18,372	$56,201	$74,573	$9,541	$45,540	$55,081	$3,291.81	4.6%	$599.80	1.1%	$0.7128	$0.5448	$0.7457	$0.5508
34		150,000	$26,336	$80,205	$106,541	$13,031	$68,310	$81,341	$27,164	$84,302	$111,465	$13,917	$68,310	$82,227	$4,923.97	4.6%	$885.97	1.1%	$0.7103	$0.5423	$0.7431	$0.5482
35		200,000	$34,861	$106,940	$141,801	$17,121	$91,080	$108,201	$35,955	$112,402	$148,358	$18,294	$91,080	$109,374	$6,556.14	4.6%	$1,172.13	1.1%	$0.7090	$0.5410	$0.7418	$0.5469
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	10,000	$2,466	$5,347	$7,813				$2,547	$5,620	$8,167				$353.91	4.5%			$0.7813		$0.8167	
39	Winter - 50%	15,000	$3,319	$8,021	$11,339				$3,426	$8,430	$11,857				$517.13	4.6%			$0.7560		$0.7904	
40	Winter - 75%	30,000	$5,876	$16,041	$21,917				$6,064	$16,860	$22,924				$1,006.78	4.6%			$0.7306		$0.7641	
41	Summer - 25%	5,000				$1,170	$2,277	$3,447				$1,226	$2,277	$3,503			$56.10	1.6%		$0.6895		$0.7007
42	Summer - 50%	15,000				$1,988	$6,831	$8,819				$2,102	$6,831	$8,933			$113.33	1.3%		$0.5880		$0.5955
43	Summer - 75%	20,000				$2,397	$9,108	$11,505				$2,539	$9,108	$11,647			$141.95	1.2%		$0.5753		$0.5824

Estimated Bill Percentiles per 2010 MCS

Liberty Utilities (EnergyNorth Natural Gas) Corp.

COMPARATIVE MONTHLY BILLING UNDER PRESENT AND PROPOSED RATES
RATE G-54 : COMMERCIAL/INDUSTRIAL - HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90%

Line	**Present Rates**	Winter	Summer	**Proposed Rates**	Winter	Summer
1						
2	Cost of Gas	$0.4792	$0.3999	Cost of Gas	$0.5065	$0.3999
3	LDAC	$0.0555	$0.0555	LDAC	$0.0555	$0.0555
4						
5	Customer charge	$761.39		Customer charge	$788.87	
6	Sales rate			Sales rate		
7	First Block Size			First Block Size		
8	Block 1	$0.0650	$0.0353	Block 1	$0.0670	$0.0374
9	Block 2	$0.0650	$0.0353	Block 2	$0.0670	$0.0374
10						
11						

Line			Monthly Bills at Present Rates						Monthly Bills at Proposed Rates						Change in Monthly Bill				Unit Costs			
13		Use per	Winter			Summer			Winter			Summer			Winter		Summer		Current		Proposed	
14		Month (therms)	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	Base Rates	COG / LDAC	TOTAL	$	%	$	%	Winter	Summer	Winter	Summer
15																						
16		1,000	$826	$535	$1,361	$797	$455	$1,252	$856	$562	$1,418	$826	$455	$1,282	$56.82	4.2%	$29.62	2.4%	$1.3611	$1.2521	$1.4179	$1.2817
17		2,500	$924	$1,337	$2,261	$850	$1,139	$1,988	$956	$1,405	$2,361	$882	$1,139	$2,021	$100.83	4.5%	$32.82	1.7%	$0.9043	$0.7953	$0.9446	$0.8084
18		5,000	$1,086	$2,674	$3,760	$938	$2,277	$3,215	$1,124	$2,810	$3,934	$976	$2,277	$3,253	$174.19	4.6%	$38.16	1.2%	$0.7520	$0.6430	$0.7868	$0.6506
19		7,500	$1,249	$4,010	$5,259	$1,026	$3,416	$4,442	$1,292	$4,215	$5,507	$1,070	$3,416	$4,485	$247.54	4.7%	$43.50	1.0%	$0.7012	$0.5922	$0.7342	$0.5980
20		10,000	$1,411	$5,347	$6,758	$1,114	$4,554	$5,668	$1,459	$5,620	$7,079	$1,163	$4,554	$5,717	$320.89	4.7%	$48.84	0.9%	$0.6758	$0.5668	$0.7079	$0.5717
21		12,500	$1,574	$6,684	$8,258	$1,203	$5,693	$6,895	$1,627	$7,025	$8,652	$1,257	$5,693	$6,949	$394.24	4.8%	$54.18	0.8%	$0.6606	$0.5516	$0.6922	$0.5559
22		15,000	$1,736	$8,021	$9,757	$1,291	$6,831	$8,122	$1,794	$8,430	$10,224	$1,350	$6,831	$8,181	$467.59	4.8%	$59.52	0.7%	$0.6505	$0.5415	$0.6816	$0.5454
23		20,000	$2,061	$10,694	$12,755	$1,467	$9,108	$10,575	$2,129	$11,240	$13,370	$1,538	$9,108	$10,646	$614.29	4.8%	$70.20	0.7%	$0.6378	$0.5288	$0.6685	$0.5323
24		25,000	$2,386	$13,368	$15,754	$1,644	$11,385	$13,029	$2,465	$14,050	$16,515	$1,725	$11,385	$13,110	$761.00	4.8%	$80.88	0.6%	$0.6302	$0.5212	$0.6606	$0.5244
25		30,000	$2,711	$16,041	$18,752	$1,820	$13,662	$15,482	$2,800	$16,860	$19,660	$1,912	$13,662	$15,574	$907.70	4.8%	$91.56	0.6%	$0.6251	$0.5161	$0.6553	$0.5191
26		35,000	$3,036	$18,715	$21,751	$1,997	$15,939	$17,936	$3,135	$19,670	$22,805	$2,099	$15,939	$18,038	$1,054.40	4.8%	$102.24	0.6%	$0.6215	$0.5125	$0.6516	$0.5154
27		40,000	$3,361	$21,388	$24,749	$2,173	$18,216	$20,389	$3,470	$22,480	$25,950	$2,286	$18,216	$20,502	$1,201.11	4.9%	$112.92	0.6%	$0.6187	$0.5097	$0.6488	$0.5126
28		45,000	$3,686	$24,062	$27,748	$2,350	$20,493	$22,843	$3,805	$25,291	$29,096	$2,473	$20,493	$22,966	$1,347.81	4.9%	$123.60	0.5%	$0.6166	$0.5076	$0.6466	$0.5104
29		50,000	$4,011	$26,735	$30,746	$2,526	$22,770	$25,296	$4,140	$28,101	$32,241	$2,661	$22,770	$25,431	$1,494.51	4.9%	$134.28	0.5%	$0.6149	$0.5059	$0.6448	$0.5086
30		55,000	$4,336	$29,409	$33,745	$2,703	$25,047	$27,750	$4,475	$30,911	$35,386	$2,848	$25,047	$27,895	$1,641.21	4.9%	$144.96	0.5%	$0.6135	$0.5045	$0.6434	$0.5072
31		60,000	$4,661	$32,082	$36,743	$2,879	$27,324	$30,203	$4,811	$33,721	$38,531	$3,035	$27,324	$30,359	$1,787.92	4.9%	$155.64	0.5%	$0.6124	$0.5034	$0.6422	$0.5060
32		75,000	$5,636	$40,103	$45,739	$3,409	$34,155	$37,564	$5,816	$42,151	$47,967	$3,597	$34,155	$37,752	$2,228.03	4.9%	$187.68	0.5%	$0.6099	$0.5009	$0.6396	$0.5034
33		100,000	$7,261	$53,470	$60,731	$4,291	$45,540	$49,831	$7,492	$56,201	$63,693	$4,532	$45,540	$50,072	$2,961.54	4.9%	$241.08	0.5%	$0.6073	$0.4983	$0.6369	$0.5007
34		150,000	$10,511	$80,205	$90,716	$6,056	$68,310	$74,366	$10,843	$84,302	$95,145	$6,404	$68,310	$74,714	$4,428.57	4.9%	$347.88	0.5%	$0.6048	$0.4958	$0.6343	$0.4981
35		200,000	$13,761	$106,940	$120,701	$7,821	$91,080	$98,901	$14,195	$112,402	$126,597	$8,276	$91,080	$99,356	$5,895.60	4.9%	$454.67	0.5%	$0.6035	$0.4945	$0.6330	$0.4968
36																						
37	**Estimated Bill Percentiles**																					
38	Winter - 25%	4,000	$1,021	$2,139	$3,160				$1,057	$2,248	$3,305				$144.85	4.6%			$0.7900		$0.8263	
39	Winter - 50%	30,000	$2,711	$16,041	$18,752				$2,800	$16,860	$19,660				$907.70	4.8%			$0.6251		$0.6553	
40	Winter - 75%	100,000	$7,261	$53,470	$60,731				$7,492	$56,201	$63,693				$2,961.54	4.9%			$0.6073		$0.6369	
41	Summer - 25%	15,000				$1,291	$6,831	$8,122				$1,350	$6,831	$8,181			$59.52	0.7%		$0.5415		$0.5454
42	Summer - 50%	50,000				$2,526	$22,770	$25,296				$2,661	$22,770	$25,431			$134.28	0.5%		$0.5059		$0.5086
43	Summer - 75%	80,000				$3,585	$36,432	$40,017				$3,784	$36,432	$40,216			$198.36	0.5%		$0.5002		$0.5027

Estimated Bill Percentiles per 2010 MCS

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
Docket No. DG 20-105 Rate Case Expense
As of June 28, 2021

Service Provider	Expense to Date	Estimated Additional Expenses	Total Estimated Expense	Description of Service
FTI Consulting	$ 385,965.46	$ -	$ 385,965.46	Revenue Requirement, Rate Design, Marginal Cost of Service , Functional Cost of Service, Decoupling Effects on EE, Cost of Capital
Keegan Werlin	114,463.50	70,536.50	185,000.00	Legal Services
Management Applications Consulting	33,245.63		33,245.63	Review Status of Depreciation Reserve
Concentric Energy Advisors	48,381.75	-	48,381.75	Review of Decoupling Mechanism
ScottMadden	27,060.00	7,500.00	34,560.00	Testimony Support
Legal Notices	466.50	-	466.50	
Court Reporter	721.00	5,400.00	6,121.00	
Customer Notice	46,241.00	-	46,241.00	
Miscellaneous	159.60	-	159.60	Printing Expenses
Subtotal	656,704.44	83,436.50	740,140.94	
Staff Consultants				
Blue Ridge Consulting	62,402.50	7,597.50	70,000.00	Revenue Requirement
J. Randall Woolridge	-	33,800.00	33,800.00	Cost of Capital
OCA Consultants				
Exeter Associates	12,923.70	-	12,923.70	Cost of Service/Rate Design
Subtotal PUC/OCA	75,326.20	41,397.50	116,723.70	
Grand Total	$ 732,030.64	$ 124,834.00	$ 856,864.64	Total Estimated Amount

(*) Additional costs are expected but not currently estimated

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Temporary/Permanent Rate Recoupment

I. Monthly Distribution Revenue at Temporary Rates

	2020			2021							
Rate Schedule	**October**	**November**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**TOTAL**
R-1	$ 76,616	$ 84,711	$ 95,454	$ 99,926	$ 88,858	$ 91,687	$ 79,080	$ 75,196	$ 68,477	$ 68,326	$ 828,332
R-3	2,947,945	4,783,958	6,536,546	7,439,623	6,451,758	5,673,831	3,752,249	2,641,484	1,852,612	1,759,630	43,839,636
R-4	195,818	325,805	445,804	508,422	441,683	396,049	277,730	195,259	135,904	126,589	3,049,061
R-5	2,187	2,562	3,100	3,416	3,180	3,054	2,275	2,072	1,810	1,829	25,484
R-6	15,009	22,662	30,903	35,584	33,310	27,963	19,925	14,016	9,367	9,118	217,858
R-7	261	413	546	621	572	482	326	234	161	157	3,771
G-41	932,318	1,478,898	2,024,612	2,282,210	2,016,717	1,786,547	1,187,441	851,412	636,112	624,777	13,821,043
G-42	880,886	1,514,648	2,059,582	2,313,781	2,019,359	1,805,610	1,144,826	713,276	444,888	407,508	13,304,364
G-43	135,714	382,676	518,929	591,563	513,601	458,625	302,913	116,760	77,990	77,286	3,176,058
G-44	1,041	1,975	3,150	3,761	3,872	3,181	1,058	589	422	421	19,470
G-45	7,371	12,584	16,964	20,438	19,365	16,086	10,014	5,253	2,511	2,196	112,781
G-46	8,656	9,618	10,580	-	962	1,924	2,885	3,847	4,809	5,771	49,051
G-51	140,954	145,796	167,241	173,638	155,900	158,844	130,708	125,151	118,757	120,311	1,437,299
G-52	164,844	223,727	263,583	275,953	246,644	240,664	191,729	141,647	137,763	141,639	2,028,194
G-53	93,319	176,732	203,468	229,170	200,041	194,987	172,159	82,322	75,155	76,556	1,503,908
G-54	77,796	118,770	102,434	103,564	84,186	94,188	107,939	67,254	69,095	75,890	901,117
G-55	313	336	373	500	482	506	310	281	267	295	3,663
G-56	-	-	-	-	-	-	-	-	-	-	-
G-57	-	-	-	-	-	-	-	-	-	-	-
G-58	2,038	2,612	2,876	2,738	2,733	2,941	2,979	1,914	1,796	1,710	24,337
TOTAL	**$ 5,683,085**	**$ 9,288,482**	**$ 12,486,145**	**$ 14,084,908**	**$ 12,283,222**	**$ 10,957,170**	**$ 7,386,544**	**$ 5,037,968**	**$ 3,637,896**	**$ 3,500,008**	**$ 84,345,428**

II. Monthly Distribution Revenue at Permanent Rates

	2020			2021							
Rate Schedule	**October**	**November**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**TOTAL**
R-1	$ 76,152	$ 84,218	$ 94,911	$ 99,363	$ 88,357	$ 91,160	$ 78,611	$ 74,739	$ 68,053	$ 67,897	$ 823,461
R-3	2,925,874	4,747,157	6,485,782	7,381,640	6,401,529	5,629,969	3,723,686	2,621,852	1,839,240	1,747,050	43,503,779
R-4	194,354	323,302	442,346	504,464	438,248	392,989	275,616	193,806	134,922	125,683	3,025,730
R-5	2,174	2,547	3,082	3,397	3,163	3,038	2,261	2,060	1,799	1,817	25,338
R-6	14,897	22,489	30,664	35,308	33,051	27,748	19,773	13,913	9,300	9,054	216,197
R-7	259	410	542	616	567	478	323	232	160	156	3,743
G-41	926,631	1,470,566	2,013,590	2,269,946	2,005,850	1,776,668	1,180,511	846,105	631,908	620,598	13,742,374
G-42	875,717	1,506,057	2,048,035	2,300,871	2,008,078	1,795,435	1,138,223	709,012	442,093	404,904	13,228,426
G-43	134,949	380,623	516,168	588,411	510,863	456,165	301,267	116,087	77,518	76,813	3,158,864
G-44	1,034	1,964	3,132	3,741	3,850	3,163	1,052	586	419	419	19,360
G-45	7,329	12,514	16,869	20,324	19,258	15,996	9,957	5,222	2,495	2,182	112,146
G-46	8,596	9,551	10,506	-	955	1,910	2,865	3,820	4,776	5,731	48,710
G-51	139,956	144,763	166,054	172,404	154,792	157,717	129,784	124,268	117,919	119,463	1,427,121
G-52	163,938	222,578	262,253	274,568	245,405	239,434	190,718	140,842	136,982	140,835	2,017,554
G-53	92,864	175,914	202,534	228,127	199,129	194,089	171,361	81,913	74,777	76,171	1,496,880
G-54	77,482	118,202	101,935	103,062	83,776	93,729	107,417	66,971	68,810	75,582	896,967
G-55	311	333	371	496	479	502	308	279	265	292	3,637
G-56	-	-	-	-	-	-	-	-	-	-	-
G-57	-	-	-	-	-	-	-	-	-	-	-
G-58	2,028	2,598	2,861	2,723	2,719	2,926	2,963	1,905	1,787	1,701	24,210
TOTAL	**$ 5,644,544**	**$ 9,225,786**	**$ 12,401,637**	**$ 13,989,464**	**$ 12,200,069**	**$ 10,883,116**	**$ 7,336,699**	**$ 5,003,612**	**$ 3,613,221**	**$ 3,476,347**	**$ 83,774,495**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Temporary/Permanent Rate Recoupment

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III. Recoupment

	2020			2021							
Rate Schedule	October	November	December	January	February	March	April	May	June	July	TOTAL
R-1	$ (464)	$ (494)	$ (543)	$ (562)	$ (502)	$ (527)	$ (469)	$ (457)	$ (424)	$ (429)	$ (4,871)
R-3	(22,071)	(36,801)	(50,764)	(57,983)	(50,228)	(43,862)	(28,563)	(19,632)	(13,372)	(12,580)	(335,857)
R-4	(1,464)	(2,502)	(3,458)	(3,958)	(3,435)	(3,059)	(2,114)	(1,452)	(982)	(906)	(23,331)
R-5	(13)	(15)	(17)	(18)	(17)	(17)	(13)	(13)	(12)	(12)	(147)
R-6	(112)	(173)	(239)	(276)	(259)	(215)	(152)	(104)	(67)	(65)	(1,661)
R-7	(2)	(3)	(4)	(5)	(4)	(4)	(2)	(2)	(1)	(1)	(28)
G-41	(5,686)	(8,331)	(11,023)	(12,264)	(10,866)	(9,879)	(6,930)	(5,307)	(4,204)	(4,179)	(78,669)
G-42	(5,169)	(8,590)	(11,547)	(12,910)	(11,281)	(10,175)	(6,603)	(4,264)	(2,795)	(2,603)	(75,937)
G-43	(765)	(2,053)	(2,761)	(3,152)	(2,738)	(2,460)	(1,646)	(673)	(472)	(472)	(17,194)
G-44	(7)	(11)	(18)	(21)	(21)	(18)	(6)	(4)	(3)	(3)	(110)
G-45	(42)	(70)	(94)	(113)	(107)	(90)	(57)	(31)	(16)	(14)	(636)
G-46	(60)	(67)	(73)	-	(7)	(13)	(20)	(27)	(33)	(40)	(341)
G-51	(997)	(1,033)	(1,187)	(1,234)	(1,108)	(1,127)	(924)	(883)	(837)	(848)	(10,178)
G-52	(906)	(1,149)	(1,330)	(1,385)	(1,240)	(1,230)	(1,011)	(805)	(781)	(804)	(10,640)
G-53	(455)	(818)	(934)	(1,042)	(912)	(898)	(797)	(409)	(378)	(386)	(7,029)
G-54	(314)	(568)	(499)	(502)	(410)	(459)	(521)	(283)	(286)	(308)	(4,150)
G-55	(2)	(2)	(3)	(4)	(3)	(4)	(2)	(2)	(2)	(2)	(26)
G-56	-	-	-	-	-	-	-	-	-	-	-
G-57	-	-	-	-	-	-	-	-	-	-	-
G-58	(10)	(14)	(15)	(15)	(14)	(15)	(15)	(10)	(9)	(9)	(127)
TOTAL	**$ (38,541)**	**$ (62,696)**	**$ (84,508)**	**$ (95,444)**	**$ (83,152)**	**$ (74,054)**	**$ (49,845)**	**$ (34,356)**	**$ (24,675)**	**$ (23,662)**	**$ (570,933)**

NOTES: Revenues calculated using actual calendar month billing determinants from October 2020 through March 2021 and calculated using estimated monthly billing determinants from April 2021 through July 2021.

NHPUC NO. 11 - GAS

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. D/B/A

LIBERTY

SUPERSEDING NHPUC No. 10

TARIFF

FOR

GAS SERVICE

Applicable

in

Thirty-five towns in New Hampshire
served in whole or in part.

(For detailed description, see Service Area)

DATED: August 13, 2021

EFFECTIVE: August 1, 2021

ISSUED BY: /s/Neil Proudman
Neil Proudman

TITLE: President

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I. GENERAL TERMS AND CONDITIONS

1 SERVICE AREA

A. Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hanover, Hollis, Hooksett, Hudson, Keene, Laconia, Lebanon, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelham, Pembroke, Sanbornton, Tilton, Windham, and part of Canterbury and Winnisquam.

2 GENERAL TERMS AND CONDITIONS

A. Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission") and is open to inspection at the offices of the Company.

B. Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the Commission and such changes, when effective, shall have the same force as the original tariff.

C. Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

D. Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

E. No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

F. Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

G. Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

H. Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

3 CHARACTER OF SERVICE – EXCLUDING KEENE CUSTOMERS

A. Gas Supply. This Tariff applies only to the supply of gas, having a thermal content of nominally 1,000 British thermal units per cubic foot at supply pressures available in the locality in which the premises to be served are situated.

B. Determination of Therms. The gas for any billing period, expressed in hundreds of cubic feet (ccf), shall be multiplied by the average BTU of the gas send out as determined below and divided by 1,000 in order to

C. Determine the number of therms consumed in the billing period. For billing purposes, gas therms shall be determined on a "dry" basis.

The BTU therm factor of the gas sendout shall be calculated for each billing cycle from the daily weighted average BTU of the natural gas delivered to the Company by its suppliers and the gas produced at the Company's peak-shaving plants. The daily average BTU content shall be determined by appropriate gas measurement devices operated by the Company or its supplier.

D. Delivery of Gas Supply. The rates specified in this tariff are based upon the supply of service to a single customer through one delivery and metering point.

E. Use of Service at Separate Properties. The use of service at two or more separate properties will not be combined for billing purposes.

4 CHARACTER OF SERVICE – KEENE CUSTOMERS

A. Gas Supply. This Tariff applies to the supply of either propane-air gas or natural gas at the company's standard heat content value for the gas supply source, adjusted for temperature and pressure, in the locality in which the premises to be served are situated.

1. For Keene customers on the propane air-gas distribution system, the supply of gas sold will be nominally 740 British thermal units per cubic foot.

2. For Keene customers on the natural gas distribution system, the supply of gas sold will be nominally 1,000 British thermal units per cubic foot.

B. Determination of Therms.

1. The propane-air gas for any billing period, expressed in hundreds of cubic feet (CCF), shall be multiplied by the average BTU/cubic foot of the gas send out as determined below and divided by 1,000 in order to determine the number of therms consumed in the billing period.

   The average BTU of the gas sendout for billing purposes shall be calculated for each billing period using the daily average BTU of propane-air gas produced by the company's production plant as determined by appropriate gas heat content measurement devices[1] operated by the company. The average BTU so calculated shall be used in determining the therms for monthly bills based on meter readings and the average BTU for the billing period.

2. The natural gas for any billing period, expressed in hundreds of cubic feet (CCF), shall be multiplied by the average BTU/cubic foot of the gas send out as determined below and divided by 1,000 in order to determine the number of therms consumed in the billing period.

   The average BTU of the gas sendout for billing purposes shall be calculated for each billing period using the daily average BTU of compressed or liquefied natural gas delivered to the company in New Hampshire by its suppliers. To determine the daily average BTU, each tanker's BTU content will be provided by the supplier or measured by the Company with appropriate gas heat content measurement devices,[1]

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[1] Typically chromatographs or calorimeters are used for measuring the heat content of gas.

including when more than one tanker is connected to the Company's natural gas system and simultaneously providing flow at any given time. The average BTU so calculated shall be used in determining the therms for monthly bills based on meter readings and the average BTU for the billing period.

5 CUSTOMER'S INSTALLATION

A. Point of Delivery. Upon request, the Company will designate a point at which the customer shall terminate his piping for connection to the meter of the Company, but such information does not constitute an agreement or obligation on the part of the Company to furnish service.

B. Space for Meter. The customer shall provide, free of expense to the Company, a dry, warm and otherwise suitable place for the regulator or regulators, meter or meters, or other equipment of the Company which may be necessary for the fulfillment of such contracts as may be entered into with the Company.

C. Location of Meter. The space provided for the Company's meters and equipment shall be convenient access to the Company's employees and, as near as possible, to the point where the service supply pipe enters the customer's building. Its location shall be such that the meter connections are not concealed by plaster or sheathing and shall be otherwise acceptable to the Company.

D. Reverse Flow. The customer may be required to install check valves or other devices to prevent compressed air or other gases from entering the Company's mains.

6 APPLICATION FOR SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of the applicant's use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Right to Reject. The Company may reject any application for service which would involve excessive cost to supply, or which might affect the supply of service to other customers, or for other good and sufficient reasons.

C. Special Contracts. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, contracts of longer terms as specified in the rate, or with a special guarantee of revenue, or both, may be required to safeguard such investment.

D. Unauthorized Use. Unauthorized connection to the Company's gas service supply facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company without notice. The use of service without notifying the Company and without enabling the company to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last meter reading of the Company's meter immediately preceding the user's occupancy as shown by the Company's books.

E. Managed Expansion Program. The Managed Expansion Program targets gas expansion in specific areas that have high potential for demand. Each Managed Expansion Program project includes a Main Extension. Customers under this program avoid a portion or all of a contribution in aid of construction which would otherwise be required absent the Managed Expansion Program.

F. Managed Expansion Program ("MEP") Premium. The markup for all MEP rates above the rates that would otherwise be applied absent the Managed Expansion Program. The MEP Premium is 30%.

7 CREDIT

A. Prior Debts. Service will not be furnished to former customers until any indebtedness to the Company for previous service has been satisfied.

B. Deposits. Before rendering or restoring service, the Company may require a deposit subject to the Commission's Rules and Regulations. (See Puc 1200 rules).

8 SERVICE AND MAIN EXTENSIONS

A. Definitions. The following are definitions of terms used in these provisions relative to main and service extensions and are applicable only in the main and service extensions provisions.

1. Service and Main Extensions. Extensions that require the construction of a new gas main and a service from that new main in order to provide requested gas service to a customer.

2. Service Extensions. Extensions from an Existing Gas Main to the point of delivery on the customer's premises.

3. Main Extension. An extension of the new gas main portion of a Service and Main Extension.

4. Existing Gas Main. A main that is installed in the street and through which gas is flowing.

5. Abnormal Costs. Abnormal Costs are service and/or main construction costs that are attributable to frost or ledge (including ditching or backfilling necessitated as a result of the presence of frost or ledge),and/or other conditions not typically encountered in service and/or main construction that are peculiar to the particular service and/or main construction concerned. Abnormal Costs are to be paid by the customer.

6. Extra Footage. The charge (contribution in aid of construction) for Extra Footage is $63.90 per foot. The charge will be updated annually by calculating the historical average cost per foot for Service Extensions, excluding overheads, for the most recent calendar year and the updated charge shall be effective April 1.

7. Estimated Annual Margin. The Estimated Annual Margin is equal to the estimated revenue to be derived from the monthly Customer Charge and delivery charge to be received from the customer for gas service utilizing the Service and Main Extension or Service Extension during the first twelve (12) months after completion of the extension. The Estimated Annual Margin does not include revenue received by the Company for the cost of gas and local distribution adjustment factor.

8. Estimated Cost of Construction. For the purpose of determining the cost of Service and Main Extensions, Estimated Cost of Construction of mains and/or services includes the cost of labor and materials for such construction, and incidental or associated miscellaneous costs, but excluding overheads. Miscellaneous costs include, but are not limited to, meter(s), traffic control and city and town road permits and degradation fees. The customer may perform on-site trenching and backfilling in accordance with the Company's specifications, in which case the Estimated Cost of Construction will be reduced to reflect the costs avoided by the Company as a result of the customer's performance of the work.

B. Costs of Extensions. In areas where the Company is authorized to operate, subject to the Application for Service provisions of this tariff, service is available as follows:

1. Residential Service Extensions. Residential Service Extensions up to 100 feet in length will be installed at no charge to customers served under either a (i) residential heating rate; or (ii) a residential non-heating rate provided that such extension is installed during the installation of a Main Extension or during the performance of work on cast iron/bare steel main replacements; unless there are Abnormal Costs associated with such extensions, in which case the customer shall be charged for the Abnormal Costs. For residential Service Extensions in excess of 100 feet, the customer will be charged for the Extra Footage, plus any Abnormal Costs. This Section 7(B)(1) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

2. Commercial and Industrial Service Extensions. Commercial and industrial Service Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service Extension, excluding any Abnormal Costs. If the Estimated Annual Margin is less than one-sixth of the Estimated Cost of Construction, the customer will be required to pay to the Company, in advance, any amount by which the Estimated Cost of Construction of the Service Extension exceeds six times the Estimated Annual Margin. Abnormal Costs are charged separately and are not included in the Estimated Cost of Construction for the purpose of this calculation. This Section 7(B)(2) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

3. Service and Main Extensions of Less Than $1,000,000. The Company shall not commence construction on a Service and Main Extension for which the Estimated Cost of Construction is less than $1,000,000 until the sum of (i) six times the Estimated Annual Margin for all commercial and industrial customers who have committed to take service, plus (ii) eight times the Estimated Annual Margin for all residential customers who have committed to take service equals or exceeds 25% of the Estimated Cost of Construction.

   a. Residential. Residential Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-eighth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-eighth of the Estimated Cost of Construction, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and eight times the Estimated Annual Margin, plus any Abnormal Costs.

   If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated equally among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main. Abnormal Costs associated with Main Extensions will be allocated equally among all customers, unless such costs can be attributed to specific customers.

b. Commercial and Industrial. Commercial and industrial Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-sixth of the cost of construction of the Service and Main Extensions, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and six times the Estimated Annual Margin, plus any Abnormal Costs.

c. If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include in such calculations the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

d. Extensions Serving Customers in More Than One Rate Class. If the Main Extension will serve both residential and commercial or industrial customers, the Company will determine whether a contribution will be required by the customers by calculating the difference between the Estimated Cost of Construction of the Main and Service Extensions and (i) six times the Estimated Annual Margin for all commercial and industrial customers to be served, plus (ii) eight times the Estimated Annual Margin for all residential customers to be served. The Company will also include in the above calculations the Estimated Annual Margin and the Estimated Cost of Construction of Service Extensions for all existing premises for which the Company reasonably anticipates will take service. If the difference described above is positive, the customers will be required to pay to the Company such difference. The amount of payment will be allocated among all metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

4. Service and Main Extensions Greater Than or Equal to $1,000,000. If the cost of the Main Extension equals or exceeds $1,000,000, then in addition to the requirements specified in Section 7(B)(3), the Company will not commence construction unless a discounted cash flow analysis

demonstrates a positive net present value over a 10-year period of the difference between the Estimated Annual Margin and the revenue requirement associated with the Estimated Cost of Construction.

A. Failure to Use Installed Gas Service. If a customer fails, within nine months after the date a service is installed under this Section 7, either in whole or in part, to make use of the service, the customer will reimburse the Company for all costs of constructing, removing and retiring the service less any contribution in aid of construction made by the customer for the service, which will be forfeited.
B. Easements, Etc. The Company is not required to construct extensions other than in public ways unless the customer provides, in advance and without expense or cost to the Company, all necessary permits, consents, authorizations and right-of-way easements, satisfactory to the Company, for the construction, maintenance and operation of the pipeline.
C. Shortest Distance. Services are run the shortest practical safe distance to the meter location. However, a customer may have the Company install a longer alternate service provided that the customer pays for the extra expense in advance of installation.
D. Winter Construction. Ordinarily, no new service pipes or main extensions are installed during the winter conditions (when frost is in the ground) unless the customer defrays the extra expenses.
E. Timing and Refunding of Contribution. Except as otherwise agreed by the Company under unusual circumstances, any required contribution in aid of construction will be made prior to installation by the Company of a service. To help cover the Company's expenses, damages and lost business, if substantial construction of the building or buildings for which gas service has been sought is not commenced by the earlier of (1) November 30th next following submission of the application; or (2) the date when the Company commences construction of the main and service concerned prior to withdrawal of the application, ten percent (10%) of the contribution will be forfeited to the Company and will not be returned to the customer. The balance of the contribution will be refunded if and when the application is withdrawn, or will be applied toward the new contribution if the customer submits a new application for service or subsequently commences construction of the building or buildings. A new application may be submitted at any time.
F. Reasonable Duration and Non-Discrimination. Under none of the foregoing provisions will the Company be required to install service pipes or to contract main extensions where the business to be secured may not be of reasonable duration or will tend, in any way, to constitute unreasonable discrimination.
G. Title. Title of all extensions constructed in accordance with the above shall be vested in the Company.
H. Other Requirements. The Company generally will not approve any application or, if it shall have given such approval, will not proceed or continue with main and/or service construction unless the Company is satisfied

1. That the final site plans, sub-division plans and plans and specification for building or buildings to be served by the main and/or service concerned, including plans for waste disposal, water and other associated systems and facilities, have been prepared and approved by owner;

2. That all permits, exceptions, approvals and authorizations of governmental bodies or agencies required for construction of such building or buildings and associated systems and facilities have been obtained;
3. That the customer is proceeding or plans promptly to proceed with such construction; and

4. That nothing has occurred or failed to occur which will or is likely to prevent or interfere with such construction.

9. INTRODUCTION OF SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of his use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Defective Installation. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

C. Unsatisfactory Installation. The Company may refuse to connect if, in its judgment, the customer's equipment or use thereof might injuriously affect the equipment of the Company or the Company's service to other customers.

10. COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

A. Meters and Regulators. The Company shall furnish and install, maintain and own, any meter or meters, regulator or regulators required in the supply of service. For certain large customers, the Company shall furnish, install and maintain, at the customer’s expense, any remote meter reading equipment to record usage for daily balancing. Such equipment shall remain the property of the Company at all times.

B. Customer's Responsibility. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property, the customer shall pay the costs of repairs and replacements.

C. Relocation and/or Replacement of Company Equipment. The original service connection, including piping, meters and all other necessary or incidental equipment, which remains the property of the Company, shall be installed by the Company at its expense unless otherwise expressly provided in this tariff. Subsequent relocation and/or replacement of any such equipment on private property, whether it be for one or more service connections, shall be performed by the Company at the customer's expense unless such work is done at the request of the Company and for its convenience, in which case the Company shall bear the expense.

D. Protection by Customer. The customer shall protect the equipment of the Company on his premises and shall not permit any persons, except a Company employee having a Company photo identification card or other Company identification, to break any seals upon or do any work on any meter, service supply pipe, or other equipment of the Company located on the customer's premises.

E. Tampering. In the event the Company's meter or other property is being tampered with or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter and for any repairs or replacements required as well as for costs of inspections, investigations, and protective installation.

F. Right of Access. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, testing, repairing, removing, or exchanging any or all equipment belonging to the Company.

G. Ownership and Removal. All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service for whatever cause.

11 SERVICE CONTINUITY

A. Regularity of Supply. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service, but should the supply be interrupted by the Company for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted or fail by reason of accident, strike, legal process, state or municipal interference, or any cause whatsoever beyond its control, the Company shall not be liable for damages, direct or inconsequential, resulting from such interruption or failure.

B. Notice of Trouble. The customer shall notify the office of the Company immediately should the service be unsatisfactory for any reason or should there be any defects, leaks, trouble, or accident affecting the supply of gas.

12 CUSTOMER’S USE OF SERVICE

A. Resale Forbidden. The customer shall not, directly or indirectly, sell, sublet, assign, or otherwise dispose of to others, gas purchased from the Company, or any part thereof, without the consent of the Company. This rule does not apply to a public utility Company purchasing gas in bulk expressly for the purpose of delivering it to others.

B. Fluctuations. Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system. In the case of violation of this rule, the Company may discontinue service or require the customer to modify its installation and/or equip it with approved controlling devices.

C. Additional Load. The service supply pipe, regulators, meters, and equipment supplied by the Company for each customer have definite capacities. The customer shall notify the Company of substantial changes in service requirements or location of appliances.

13 INSPECTIONS

A. Company's Right to Inspect. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any time later and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements. However, such inspection, failure to inspect, or failure to reject shall not render the Company liable or responsible for any losses or damage resulting from defects in the installation, piping or appliances, from violation of Company rules, or from accidents which may occur upon the premises of the customer.

14 MEASUREMENT

A. Supply of Meters. The measurement of gas service shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment and may, from time to time, change or alter the equipment. The Company's sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

B. Special Measurements. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments on the premises of any customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the customer's load.

15 METER TESTS

A. Meter Tests. Meters are tested according to NHPUC Rules and Regulations. (See Puc 500 rules).

B. Request Tests. The fee for a special request test is $20.00 when scheduled at the mutual convenience of the Company and the customer; otherwise the amount is $30.00. (See Puc 500 rules).

C. Customer's Bill Adjustment. Should any meter fail to register correctly, the quantity of gas consumed will be determined by the Company based on information supplied by the customer and known by the Company subject to NHPUC Rules and Regulations. (See Puc 500 rules).

16 DISCONNECTION BY THE COMPANY

A. Disconnection by the Company. The Company may disconnect its service to a customer for violation of its rules subject to NHPUC Rules and Regulations. (See Puc 1200 rules).

B. Non-Payment Shut-Off. The Company may disconnect its service on reasonable notice and remove its equipment in case of non-payment of amounts billed for gas usage.

C. Shut-Off for Cause. The Company may disconnect its service on reasonable notice if entry or access to its meter or meters is refused, obstructed, or hazardous, or for other violation of the Company's standard requirements.

D. Safety Shut-Off. The Company may disconnect without notice if the customer's installation has become dangerous or defective.

E. Defective Equipment. The Company may disconnect without notice if the customer's equipment, or use thereof, might injuriously affect the equipment of the Company or the Company's service to other customers.

F. Shut-Off for Fraud. The Company may disconnect without notice for abuse, fraud or tampering with the connections, meters or other equipment of the Company.

G. Reconnection Charge. A reconnection charge is made for reconnection of service discontinued by the Company and is payable in advance in addition to all other amounts due. The reconnection charge is made instead of the meter account charge. The amount of the reconnection charge is the same as the comparable meter account charge except when it has been necessary to dig up the service pipe or connection to effect discontinuance of service. In such cases, the reconnection charge is the price of removal and restoration of service pipe or connection.

17. COST OF GAS CLAUSE EXCLUDING KEENE

A. Purpose. The purpose of this Cost of Gas Clause is to establish procedures that allow the Company, subject to the jurisdiction of the Commission, to adjust, on a semiannual basis, its rates for firm gas sales in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchased gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit to customers receiving firm service from the Company all supplier refunds and capacity release sales.

B. Applicability. This Cost of Gas Clause ("COGC") shall be applicable to the Company and all firm gas sales made by the Company, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the NHPUC. See Section 17(N), "Other Rules."

C. Cost of Firm Gas Allowable for COGC. All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, hedging related costs, other gas supply expense incurred to procure and transport supplies and commodity related bad debt expense, the gas used in Company operations, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the COGC. Any costs recovered through application of the COGC shall be identified and explained fully in the semiannual filings outlined in Section 17(M).

D. Effective Date of Cost of Gas Factor. The seasonal Cost of Gas Factor ("COG") shall become effective upon NHPUC approval on the first day of each season as designated by the Company. Unless otherwise notified by the NHPUC, the Company shall submit COG filings as outlined in Section 17(M) of this clause on or before the first business day in September...

E. Definitions. The following terms shall be defined in this section, unless the context requires otherwise.

1. Bad Debt Expense: The uncollectible expense attributed to the portion of the Company's revenue associated with the recovery of gas costs under this clause.

2. Capacity Release Revenues: The economic benefit derived from the sale or release of transportation and storage capacity that the Company has under contract.

3. Carrying Charges: Interest expense calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end of month balance.

4. Correction Factor: Seasonal Adjustment necessary to align the peak day volumes used to calculate the Commercial and Industrial load factor ratios with the seasonal Commercial and Industrial High Winter and Low Winter throughput volumes applied to the cost of gas calculations.

5. Direct Gas Costs: All purchased gas costs including supplier, storage and pipeline demand and commodity costs, as well as the commodity costs for local manufactured gas (Liquid Propane Gas ("LPG") and Liquefied Natural Gas ("LNG")).

6. Economic Benefit: The difference between the revenues received and the marginal cost determined to serve non-core customers.

7. Inventory Finance Charges: As billed in each Winter Season for annual charges. The total shall represent an accumulation of the projected charges as calculated using the monthly average of financed inventory at the existing or anticipated financing rate through a trust or other financing vehicle.

8. Local Production and Storage Capacity Costs: The costs of providing storage service from the Company's storage facilities (*i.e.*, LNG and LPG) as determined in the Company's most recent rate proceeding.

9. Market Based Allocator ("MBA"): The method used to allocate gas costs among Commercial and Industrial Customer Classifications. These ratios are presented in Section 17(F).

10. Non-Core Commodity Costs: The commodity cost of gas assigned to non-core sales to which the COG is not applied.

11. Non-Core Sales: Sales made under non-traditional off-system sales.

12. Non-Core Sales Margins: The economic benefit derived from non-core transactions to which the COG is not applied, including non-core sales generated from the use of the Company's Gas Supply Resource portfolio.

13. Summer Commodity: The gas supplies procured by the Company to serve firm load in the Summer Season.

14. Summer Demand: The gas supply demand and transmission capacity procured by the Company to serve firm load in the Summer Season.

15. Summer Season: The calendar months May 1 through October 31.

16. Off-System Sales Margin: The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

17. Winter Commodity: The gas supplies procured by the Company to serve firm load in the Winter Season.

18. Winter Demand: Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.

19. Winter Season: The calendar months November 1 through April 30.

20. PR Allocator: The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.

21. Purchased Gas Working Capital: The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

F. Approved Cost. The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

Variable	Description	Approved Figure
PS	Production and Storage Capacity	$3,893,588
WCA%	Working Capital Allowance Percentage	3.91%

<table>
<tr><th>Bad Debt % Measurement and Reconciliation Period</th><th>COG Recovery Period</th><th>Actual Bad Debt Rate</th><th>Bad Debt allowed Recovery Rate</th></tr>
<tr><td>May 2010 – April 2011</td><td>November 2011 – October 2012</td><td>Actual</td><td>Actual</td></tr>
<tr><td rowspan="3">May 2011 – April 2012</td><td rowspan="3">November 2012 – October 2013</td><td>Greater than 2.9%</td><td>Actual less 0.4</td></tr>
<tr><td>2.5% to 2.9%</td><td>2.5%</td></tr>
<tr><td>Less than 2.5%</td><td>Actual</td></tr>
<tr><td rowspan="3">May 2012 - April 2013 and each subsequent May – April period thereafter</td><td rowspan="3">November 2013 - October 2014 and each subsequent November – October period thereafter</td><td>Greater than 3.3%</td><td>Actual less 0.8</td></tr>
<tr><td>2.5% to 3.3%</td><td>2.5%</td></tr>
<tr><td>Less than 2.5%</td><td>Actual</td></tr>
</table>

If the Company's actual bad debt percentage is reduced to 2.5% or less during any 12 month period, which need not be the same 12 months as the measurement periods defined above, then beginning with the reconciliation filing for the period during which this bad debt percentage was achieved the Company shall thereafter recover its actual gas supply related bad debt on a fully reconcilable basis and the percentages in the table above shall no longer apply. The actual bad debt percentage shall be calculated by dividing the Company's actual net write-offs for the relevant measurement period by its revenue for the same period.

G. Cost of Gas (COG) Calculations by Customer Class. The COG Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group to the total system unit capacity cost that is determined in the Company's submittal of its Capacity

Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment C of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

GROUP	CUSTOMER CLASSES
Residential	Residential Heating and Non-Heating
Commercial and Industrial: Low Winter Use	G-51 through G-58
Commercial and Industrial: High Winter Use	G-41 through G-46

Winter Season Cost of Gas Formula (CGw)

The Winter Season COG shall be comprised of Winter Demand costs, Winter commodity costs, Winter reconciliation costs, Winter working capital reconciliation, Winter bad debt expenses, local production and storage capacity costs, and miscellaneous and A&G costs calculated at the beginning of the Winter Season according to the following formula:

$$CGw = Dw + Cw + Rw + WCRw + BDw + PS + ((MISC + Rbd) \times \frac{W{:}Sales)}{A{:}Sales}$$

Winter Demand Cost (Dw) Formula

Dw = DEMw – NCSMw + WCwd – R1d – R2d
and:

NCSMw = CRRw + OSSMw + SBdw
and:

WCwd = (DEMw – NCSMw) × WCA% × CC
where:

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers previously defined.

BDw = Bad Debt expense for the Winter Season.

Cw = Commodity-related direct gas cost for the Winter Season.

Dw = The total Winter Demand costs.

DEMw = Demand Charges allocated to the Winter Season defined in Section 17(E).

NCSMw = The Non-Core Sales Margins equal to the sum of the Winter Season returnable Capacity Release Revenues, and Off-System Sales Margins.

WCwd = Working Capital allowable associated with demand charges allocated to the Winter Season as defined in Section 17(K).

R1d, R2d = Supplier demand-related refunds - The Supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 17(I).

CRRw = The returnable Capacity Release Revenues allocated to the Winter Season. See Section 17(E).

OSSMw = The returnable Off-System Sales Margins allocated to the Winter Season. See Section 17(E).

SBdw = Demand revenues received from Firm Stand-By Sales Service customers in the Winter Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 17(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rw = Reconciliation Costs – Winter Season deferred gas costs, Account 1920-1740 balance, inclusive of the associated Account 1920-1740 interest, as outlined in Section 17(J).

WCRw = Working Capital reconciliation adjustment associated with Winter Gas Costs - Account 1163-1422 balance as outlined in Section 17(K).

PS = The total dollar amount of costs associated with the local production and storage capacity gas less any production and storage capacity assignment revenues. Refer to Section 17(F) for this dollar amount.

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. Refer to Section 17(F) for this dollar amount.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance

W:Sales = Forecasted firm sales volumes associated with the Winter Season.

A:Sales = Forecasted annual firm sales volumes.

Winter Season Commodity (Cw) Formula

Cw = COMw + FC + WCwc – R1c – R2c
and:

COMw = WSC – NCCCw - SBcw
and:

WCwc = (COMw + FC) × WCA% × CC
where:

COMw = Commodity Charges allocated to the Winter Season as defined in Section 17(E).

FC = Inventory finance charges as defined in Section 17(E).

WCwc = Working Capital Allowable Associated with commodity charges allocated to the Winter Season as defined in Section 17(K).

R1c, R2c = Supplier commodity-related refunds - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds". See Section 17(I).

WSC = Commodity charges associated with gas supply sent out in Winter Season as defined in Section 17(E)

NCCCw = Non-Core Commodity Costs incurred in the Winter Season as defined in Section 17(E).

SBcw = Winter Season commodity revenues received from Firm Stand-By Gas Supply Service sales customers.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 17(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Winter Bad Debt (BDw) Formula

BDw = BD% x (Dw + Cw + Rw + WCRw)

where:

BDw = Forecasted gas supply cost related Bad Debt Expense calculated for Winter Season.

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 17(F) Bad Debt Allowed Recovery Rate for this percentage.

Dw = Demand related costs in the Winter Season as previously defined.

Cw = Commodity related costs in the Winter Season as previously defined.

Rw = Reconciliation Costs – Winter Season deferred gas costs as previously defined.

WCRw = Winter Season Working Capital Reconciliation adjustment as previously defined.

Residential Winter Season Cost of Gas (COGwr)

All residential firm sales customers will pay the same Cost of Gas for the Winter Season. The factor represents the total forecasted Winter Season average cost of gas rate. This factor is calculated according to the following formula:

$$\text{COGwr} = \frac{\text{CGw}}{\text{W:Sales}}$$

where:

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers previously defined.

W:Sales = Forecasted sales volumes associated with the Winter Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Summer Season Cost of Gas (COG) Formula (CGs)

The Summer Season COG shall be comprised of Summer demand costs and Summer commodity costs, Summer reconciliation costs, Summer working capital reconciliation, plus a Summer bad debt charge, and a miscellaneous and A&G charge calculated at the beginning of the Summer Season according to the following formula:

$$CGs = Ds + Cs + Rs + WCRs + BDs + \left((MISC + Rbd) \times \frac{S:Sales}{A:Sales}\right)$$

Summer Demand Cost (Ds) Formula

Ds = DEMs + WCsd – Rld – R2d
and:

WCsd = DEMs × WCA% × CC
where:

A:Sales =	Forecasted annual sales volumes.
BDs =	Bad Debt Expense for Summer Season.
Cs =	Commodity-related direct gas costs for the Summer Season.
CGs =	The total cost of gas for the Summer Season for the Company's firm sales customer previously defined.
DEMs =	Demand charges allocated to the Summer Season defined in Section 17(E).
MISC =	The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. Refer to Section 17(F) for this dollar amount.
R1d, R2d =	Supplier refunds from pipeline demand charges - The per unit supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 17(I).
Rs =	Summer Season Reconciliation Costs - Account 1920-1741 balance, inclusive of the associated Account 1920-1741 interest, as outlined in Section 17(J).
S:Sales =	Forecasted sales volumes associated with the Summer Season.
WCA % =	Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 17(F) for this percentage.
CC =	Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.
Rbd =	Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance.
WCRs =	Working Capital reconciliation adjustment associated with Summer gas costs – Account 1163-1424 as outlined in Section 17(K).
WCsd =	Working Capital allowable costs associated with demand costs allocated to the Summer Season as defined in Section 17(K).

Summer Season Commodity Cost (Cs) Formula

Cs = COMs – NCCCs + WCsc – R1c – R2c
and:

WCsc = (COMs – NCCCs) × WCA% × CC
where:

COMs = Commodity charges associated with gas supply sent out in the Summer Season as defined in Section 17(E).

WCsc = Working Capital allowable costs associated with commodity charges allocated to the Summer Season as defined in Section 17(K).

R1c, R2c = Supplier refunds from pipeline commodity charges - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds."

NCCCs = Non-core commodity costs incurred in the Summer Season as defined in Section 17(E).

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 17(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Summer Bad Debt (BDs) Formula

BDs = BD% x (Ds + Cs + Rs + WCRs)
where:

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 17(F) Bad Debt Allowed Recovery Rate for this percentage.

BDs = Forecasted gas supply related Bad Debt Expense calculated for Summer Season defined in Section 17(E).

Ds = Demand related costs in the Summer Season as previously defined.

Cs = Commodity related costs in the Summer Season as previously defined.

Rs = Reconciliation Costs – Summer deferred gas costs as previously defined.

WCRs = Summer Season Working Capital Reconciliation adjustment as previously defined.

Residential Summer Season Cost of Gas (COGsr)

All residential firm sales customers will pay the same cost of gas for the Summer Season. The factor represents the total forecasted Summer Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGsr = \frac{CGs}{S:Sales}$$

where:

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

S:Sales = Forecasted sales volumes associated with the Summer Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Commercial and Industrial Winter and Summer Season Cost of Gas

The Commercial and Industrial customer classes Winter Season Cost of Gas will be based on the Winter Season average cost of gas components used for the Residential Winter Season Cost of Gas. A separate Winter Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58 and a separate Winter Season Cost of Gas Factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

The Commercial and Industrial customer classes Summer Season Cost of Gas will be based on the Summer Season average cost of gas components used for the Residential Summer Season Cost of Gas. A separate Summer Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53,G-54, G-55, G-56, G-57, and G-58 and a separate Summer Season Cost of Gas factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

These Cost of Gas Factors will be computed by applying ratios to the average demand portion of the Winter and Summer Season's cost of gas unit rate times the correction factor and then adding the remaining Residential average cost of gas unit rate.

These factors are calculated according to the following formulas:

Low Winter Use (COGwl) Formula Winter Season

COGwl = RATIOl x CFw x CGwd + CGwo

Low Winter Use (COGsl) Formula Summer Season

COGsl = RATIOl x CFs x CGsd + CGso

and:

$$RATIOl = \frac{DCcl}{DDcl} \div \frac{DCc}{DDc}$$

and:

High Winter Use (COGwh) Formula Winter Season

COGwh = RATIOh x CFw xCGwd + CGwo.

High Winter Use (COGsh) Formula Summer Season

COGsh = RATIOh x CFs x CGsd + CGso

and

RATIOh = <u>DCch</u> ÷ <u>DCc</u>
DDch = DDc

and:

$$CFw = \frac{(WL{:}Sales + WH\ Sales)}{(RATIOl \times WL{:}Sales) + (RATIOh \times WH{:}Sales)}$$

$$CFs = \frac{(SL{:}Sales + SH{:}Sales)}{(RATIOl \times SL{:}Sales) + (RATIOh \times SH{:}Sales)}$$

$$CGwd = \frac{Dw}{W{:}Sales}$$

$$CGwo = \frac{CGw - Dw}{W{:}Sales}$$

$$CGsd = \frac{Ds}{S{:}Sales}$$

$$CGso = \frac{CGs - Ds}{S{:}Sales}$$

DCcl = Bcl * PLrate + (DDcl – Bcl) * REMrate

DCch = Bch * PLrate + (DDch- Bch) * REMrate

PLrate = PL/ PLmdcq

$$REMrate = \frac{(DCc - (Bc*PLrate))}{DDc - Bc}$$

$$DCc = \frac{(DC \times DDc)}{DD}$$

where:

Bc =	The daily base load for all the Commercial and Industrial rate classes
Bch =	The daily base load for the Commercial and Industrial rate classes G-41, G-42, G-43, G-44, G-45 and G-46.
Bcl =	The daily base load for the Commercial and Industrial rate classes G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.
CFs =	Summer Season Commercial and Industrial gas cost correction factor.
CFw =	Winter Season Commercial and Industrial gas cost correction factor.
CGs =	The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.
CGw =	The total cost of gas for the Winter Season for the Company's firm sales customers as previously defined.

DC =	The annual forecasted pipeline, storage and peaking demand charges plus the total production and storage capacity costs, as stated in Section 17(F).
DCc =	The Commercial and Industrial rate classes pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs.
DCch =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to Commercial and Industrial High Winter Use rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DCcl =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to the Commercial and Industrial Low Winter Use rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
DD =	Total peak design day determinants.
DDc =	The peak design day determinants allocated for all the Commercial and Industrial rate classes.
DDch =	The peak design day determinants for the Commercial and Industrial rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DDcl =	The peak design day determinants for the Commercial and Industrial rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
Ds =	The total Summer Demand charges as defined below.
Dw =	The total Winter Demand charges as previously defined.
PL =	The annual forecasted pipeline only demand charges
PLmdcq =	The maximum daily contract pipeline volume available to the Company.
PLrate =	The pipeline demand rate.
RATIOh =	Ratio of the average high Winter Use class Cost of Gas low load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
RATIOl =	Ratio of the average low Winter Use class Cost of Gas high load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
REMrate =	The weighted average demand rate for storage and peaking supplies.
S: Sales =	Forecasted sales volumes associated with the Summer Season.
SH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
SL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.
W:Sales =	Forecasted sales volumes associated with the Winter Season.
WH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
WL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.

H. Non-Core Sales Margins (“NCSM”). One hundred percent (100%) of margins from Off-System Sales and all revenues from Capacity Release will be credited to firm sales customers during the winter season through operation of the COG.

I. Gas Suppliers' Refunds. Account 5541-8048: Refunds from suppliers of gas, from upstream capacity suppliers and suppliers of product demand are credited to Account 5541-8048, "Commodity and Demand Refunds." Transfers from these accounts will reflect as a credit in the semiannual calculation of the COG to be calculated as follows:

Refund programs shall be initiated with each semiannual COG filing and shall remain in effect for a period of one year. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. Refunds shall be segregated by demand and commodity charges and distributed volumetrically, producing per unit refund that will return the principal amount with interest as calculated using the Company's average short-term cost of borrowing for the month to the average of the beginning and end of month balances of refunds. The Company shall track and report on all Account 5541-8048 activities as specified in Section 17(K).

J. Reconciliation Adjustments – Various Accounts.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Capacity Costs Allowable per Winter Season Formula shall be:

(1) Charges associated with upstream storage transmission capacity and product demand procured by the Company to serve firm load in the Winter Season, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Charges associated with peaking, downstream production and storage capacity to serve firm load dispatching costs, and other administrative and general expenses in connection with purchasing gas supplies in the Winter Season from the Company's most recent test year and allocated to firm sales service.

(3) Non-Core Sales Margins or economic benefits associated with returnable capacity release and off-system sales.

(4) Credits associated with firm Stand-by Gas Supply Service Monthly Reservation Charges, daily imbalance charges and fixed component of penalty charges billed transportation customers in the Winter peak Season.

(5) Winter Season Demand Cost carrying charges.

b. Gas Costs Allowable Per Winter Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter Season.

(2) Credit non-core commodity costs assigned to non-core customers to which the COGC does not apply, as defined in Section 17(H) (NCCCw).

(3) Inventory finance charges (FC).

(4) Winter Season commodity cost carrying charges.

c. Capacity Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with transmission capacity and product demand procured by the Company to serve firm load in the Summer Season

(2) Credits associated with daily imbalance charges and fixed component of penalty charges billed transportation customers in the Summer Season.

(3) Summer Season demand cost carrying charges.

d. Gas Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 17(E).

(3) Summer Season commodity cost carrying charges.

e. Costs Allowable Per Bad Debt Formula shall be:

(1) Costs associated with uncollected gas costs, incurred by the Company to serve sales load. Such costs represent the bad debt expense related to the gas supply related write-off of sales customers and will be computed by multiplying actual gas costs by the Bad Debt Allowed Recovery Rate specified in Section 17(F). The reconciliation adjustment each season will be computed as the difference between the actual supply related bad debt revenues and the actual gas costs multiplied by the actual Bad Debt Allowed Recovery Rate as specified in Section 17(F).

(2) Account 1920-1743 – Annual Bad Debt, carrying charges.

2. Calculation of the Reconciliation Adjustments: These accounts contain the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Winter Season Gas Costs (Account 1920-1740) and Summer Season Gas Costs (Account 1920-1741), Account 1920-1740 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Winter Season Gas Cost for each Customer Classification, (COGwr, COGwl and COGwh) times monthly firm sales volumes for each Customer Classification, and the total costs allowable per the Winter Season gas cost formula. Account 1920-1741 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Summer Season Gas Cost for each Customer Classification, (COGsr, COGsl and COGsh) times monthly firm sales volumes for each Customer Classification, and the total gas costs allowable per the Summer Season demand formula.

Carrying Charges shall be calculated on the average monthly balance of each subaccount. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

The annual bad debt reconciliation adjustments Rbd shall be determined for use, incorporating the bad debt balances in Account 1920-1743.

The bad debt account balance contains the accumulated difference between the Bad Debt Allowed Recovery Rate for the applicable period multiplied by the actual gas costs and the actual supply related bad debt revenues for the Winter and Summer COG filings.

The Winter Season reconciliation shall be filed with the NHPUC no later than July 29 of each year.

The Summer Season reconciliation shall be filed with the NHPUC no later than January 31 of each year.

K. Working Capital Reconciliation Adjustments - Accounts 1163-1422 and 1163-1424.

1. *The following definitions pertain to reconciliation adjustment calculations:*

a. Working Capital Demand Gas Costs Allowable per Winter Season Gas Formula shall be:

(1) Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the Winter period, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Carrying charges.

b. Working Capital

(3) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter season.

(4) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 17(E).

(5) Carrying charges.

c. Working Capital Demand Gas Costs Allowable per Summer Season Gas Formula shall be:

(6) Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Summer Season.

(7) Carrying charges.

d. Working Capital Commodity Gas Costs Allowable per Summer Season Gas Formula shall be:

(8) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(9) Non-core commodity costs associated with non-core sales.

(10)Carrying charges.

e. The Winter and Summer Cost of Gas working capital allowances shall be calculated by applying the Working Capital Allowance Percentage (WCA%) set forth in Section 17(F).

2. Calculation of the Reconciliation Adjustments

a. Accounts 1163-1422 and 1163-1424 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance cost. The actual monthly working capital allowance shall be calculated by multiplying the actual gas costs times the Working Capital Allowance Percentage (WCA%) set forth in Section 17(F), to the actual Direct Gas Costs allowable.

b. The Winter Season working capital reconciliation adjustment (WCRw) shall be determined for use in the Winter Season Gas Cost calculations incorporating the Winter Season working

capital account 1163-1422. A Summer Season working capital reconciliation adjustment (WCRs) shall be determined for use in the Summer Season Gas Cost calculations incorporating the Summer Season working capital account 1163-1424 balance.

L. Application of COG to Bills: The Company will employ the COGs as follows: The COGs ($/therm) for each customer group for each season shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volume within the corresponding customer classification. The Cost of Gas will be applied to gas consumed on or after the first day of the month in which the cost of gas becomes effective.

M. Information Required to be Filed with the NHPUC.

1. Reconciliation Adjustments: The Company shall file with the NHPUC a seasonal reconciliation of gas costs and gas cost collections containing information in support of the reconciliation calculation set out in Sections 17(J) (2) and 17(K) (2). Such information shall include the complete list of gas costs recoverable through the COGC over the previous season. This seasonal reconciliation shall be filed with the respective seasonal COG reconciliation filing, along with complete documentation of the reconciliation adjustment calculations.

   Additionally, information pertaining to the Cost of Gas shall be filed with the NHPUC in accordance with the format established by the NHPUC. Reporting requirements include filing the Company's monthly calculation of the projected over or under-collection with the NHPUC, along with notification by the Company to the NHPUC of any revised COG for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month.

   The Company shall file with the NHPUC an annual reconciliation of bad debt expense and bad debt collections containing information in support of the reconciliation calculation set out in Sections 17(J) (1) and 17(J) (2). Such information shall detail the revenues collected as an allowance for bad debt, as well as the actual bad debt expense associated with gas cost recoverable through the COGC over the 12-month period ending April 30th. This annual reconciliation of bad debt expenses shall be filed with the Winter COG reconciliation filing, along with documentation.

2. Commercial and Industrial COG Ratio: The following factors will be filed annually by the Company for informational purposes. Significant changes in these factors signal the need to evaluate the COG ratios. These variables will assist in predicting significant shifting of the MBA-based escalator of gas costs and resulting changes in the COG ratios:

   a. The percentage of load migration from sales to transportation service in the Commercial and Industrial High and Low Winter Use classes.

   b. The ratio of delivered costs of winter supplies to pipeline delivered supplies.

   c. The July and August consumption for the Commercial and Industrial High and Low Winter classes as a percentage of their annual consumption.

N. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of this tariff, upon such terms that it may determine to be in the public interest.

2. The Company may, without further NHPUC action, adjust the approved COG upward or downward monthly based on the Company's calculation of the projected over or under-collection for the period, but the cumulative adjustments upward shall not exceed twenty-five percent (25%) of the approved COG.

3. The Company may, at any time, file with the NHPUC an amended COG.

4. The operation of the Cost of Gas Clause is subject to all powers of suspension and investigation vested in the NHPUC.

5. The Company shall file both seasonal COG filings on or before the first business day in September. The summer portion of the filing will include COG rates effective May 1 of the following year.

O. Reconciliation Adjustment Accounts.

1163-1422

Winter Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas working capital allowance revenues and Winter Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1163-1424

Summer Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas working capital allowance revenues and Summer Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1740

Winter Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas revenues and Winter Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1741

Summer Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas revenues and Summer Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1743

Annual Bad Debt Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Annual bad debt revenues and annual bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

5541-8048

Commodity and Demand Refunds: This account shall be used to record the refunds from upstream commodity supplies and suppliers of product commodity and transfers of credits in the semiannual calculation of the COG as well as to record the refunds from upstream capacity supplies and suppliers of product demand and transfer of credits in the semiannual calculation of the COG. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

P. Firm Transportation Cost of Gas Charge. To permit the Company to charge its firm transportation customers with a portion of the cost of gas produced by the Company between November 1 and April 30 of each year, there is a Firm Transportation Cost of Gas Charge ("FTCG") which applies to all firm transportation billed under this tariff. This volumetric charge is to compensate firm sales customers for the increase in gas costs, through the use of supplemental liquid fuels, attributable to firm transportation customers during the Winter Period.

1. Application. The FTCG will be calculated for the Winter Period, defined as the period from November 1 through April 30. The FTCG will be applied to billings commencing with the first November revenue billing cycle

2. Purpose. The amount of the FTCG is the estimated liquid costs used for pressure support purposes multiplied by the transportation throughput as a percentage of the total system throughput for the Winter Period. The resulting amount shall be adjusted by the prior period over or under collection, if any, and shall be recovered over the estimated total transportation throughput subject to the FTCG to yield a per therm volumetric charge. The FTCG shall be computed to the nearest one hundredth cent per therm and shown separately on customers' bills. At the conclusion of the Winter Period, the Company will calculate the extent that the FTCG revenues are greater or lesser than actual unit cost. The revenue and liquid costs will be reconciled so that all liquids costs shall be collected from either firm sales or firm transportation customers.

3. Changes. The amount of the FTCG may be changed within the period whenever the unit cost materially deviates from the anticipated unit cost

4. Reporting. The Company shall submit to the New Hampshire Public Utilities Commission, on or before the first business day in September, a copy of the FTCG computation. A reconciliation of the prior period under/over collection will be submitted to the New Hampshire Public Utilities Commission no later than July 29.

Q. Fixed Price Option Program. Fixed Price Option Program. An alternative to the traditional Winter Period cost of gas pricing mechanism may be elected by a residential customer (rates R-1, R-3, R-4, R-5 or R-6) pursuant to the Company's Fixed Price Option Program (the "Program"). The Company may offer up to 50% of its weather normalized firm sales for the prior Winter Period under the Program. The cost of gas rate offered under the Program will remain fixed for all Winter Period deliveries commencing November 1 and ending April 30. The Company shall submit to the New Hampshire Public Utilities Commission on or before September 1 of each year a copy of the fixed price option computation. Once elected, customers must remain on the Program for the duration of the Winter Period, unless service is terminated. There are no maximum or minimum usage levels. No sign up fees apply.

18 COST OF GAS CLAUSE – KEENE DIVISION

A. Purpose. To permit the Company to charge its customers in the Keene Division with the cost of gas purchased or produced. A cost of gas rate will be applied to all firm gas billed under this tariff as calculated on the appropriate pages.

B. Application. A cost of gas rate will be calculated for the winter heating period, defined as the period from November 1 through April 30, and a cost of gas rate will be calculated for the summer period, defined as the period from May 1 through October 31.

The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

19 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE AND NORMAL WEATHER ADJUSTMENT

A. Purpose. The purpose of the Local Distribution Adjustment Clause (“LDAC” or this “Clause”) is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges (“CC”), Revenue Decoupling Adjustment Factor (“RDAF”), Winter Period Surcharges (“WPS”), Environmental Surcharges (“ES”) including the Relief Holder Surcharge (“RHS”) and the Manufactured Gas Program Surcharge (“MGP”), rate case expenses and recoupment (“RCE”), Gas Assistance Program costs (“GAP”) and any other expenses the NHPUC may approve from time to time. The purpose of the Normal Weather Adjustment ("NWA") is to establish procedures that allow the Company, subject to the jurisdiction of NHPUC, to calculate and apply, for each customer on a monthly basis, the Normal Weather Factor ("NWF").

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 19(K) "Other Rules." ______This Clause is applicable to all rates and charges on a Rate Class basis. The application of the CC, RDAF, ES, RCE and GAP is applicable to all therms and therefore the application to all customers, including Managed Expansion Program Customers, is at the same rate per therm as the corresponding non-Managed Expansion Program Customers.

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1 and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

D. Revenue Decoupling Adjustment Factor.

1. Purpose: Revenue decoupling eliminates the link between volumetric sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage by establishing an allowed revenue per customer ("RPC"). The Company is allowed to collect that RPC for the number of actual customers it has in a given month. The purpose of the Revenue Decoupling Adjustment Factor ("RDAF") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its rates for firm gas sales and firm transportation in order to reconcile the difference between the Actual Revenue collected and the Allowed Revenue. The purpose of the Normal Weather Adjustment ("NWA") is to adjust each customer's bill for the difference in delivery charges caused by the variation in actual Heating Degree Days ("HDDs") from normal HDDs during the Winter Period.

2. Effective Date: The RDAF and NWA shall take effect beginning on November 1, 2018, and replace the Lost Revenue Adjustment Mechanism (LRAM) established in Order No. 25,932 (Docket No. DE 15-137).

3. Applicability: The Revenue Decoupling Adjustment Factor and NWA shall apply to all of the Company's firm tariff rate schedules, excluding special contracts, as determined in accordance with the provisions of this RDAF and NWA.

4. Definitions: The following definitions shall apply throughout Section 19D:

   a. Actual Number of Customers is the actual number of Equivalent Bills for the applicable Rate Class for each applicable month of the Decoupling Year.
   b. Equivalent Bill. Customers are billed on different days of the month. To calculate the number of customers in a month for purposes of calculating the Monthly Actual Revenue it is necessary to use Equivalent Bills as a representation for customers. Equivalent Bills are calculated by dividing the number of days in the billing period of each customer's bill by 30.
   c. Billing Year is the 12-months commencing November 1 immediately following the completion of the Decoupling Year.
   d. Decoupling Year. The first Decoupling Year shall be the 10-month period from November 1, 2018 to August 31, 2019. Each subsequent Decoupling Year shall be the twelve months commencing September 1 through August 31.
   e. Rate Class are customers taking service pursuant to the rate schedules combined as follows: Rates R-1 and R-5, Rates R-3, R-4, R-6, and R-7, Rates G-41 and G-44, Rates G-42 and G-45, Rates G-43 and G-46, Rates G-51 and G-55, Rates G-52 and G-56, Rates G-53 and G-57, and Rates G-54 and G-58.
   f. Customer Class Group (CG) is the group of rate schedules combined for purposes of calculating the Revenue Decoupling Adjustment and the RDAF. The two Customer Class Groups are as follows:

Residential Customer Class Group (CG1): defined as both Residential Non-Heating Rate Class and Residential Heating Rate Class, shall consist of all customers taking service pursuant to the Company's residential rate schedules. CG1 shall include customers taking service under rate schedules R-1, R-3, R-4, R-5, R-6 and R-7.

Commercial and Industrial Customer Class Group (CG2): shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

g. Distribution Revenue is the revenue from the Company's firm sales service and firm delivery service customers and does not include other revenue, special contracts, and all revenues recovered from Cost of Gas filings.

5. Calculation of Revenue Per Customer

a. Definitions:

i. Initial Approved Revenue is the Distribution Revenue for each Rate Class less MEP Premium revenues, all as approved by Order of the Commission in a rate case, to determine the Commission approved Initial RPC per Rate Class.

ii. Incremental Approved Revenue is the amount of any change to the Initial Approved Revenue that is approved by Order of the Commission between rate cases and used to determine the Commission approved Incremental RPC and new Approved RPC.

iii. Initial Revenue per Customer ("Initial RPC") is calculated for each Rate Class and approved by Order of the Commission in a rate case.

iv. Incremental Revenue per Customer ("Incremental RPC") divides the Incremental Approved Revenue for each Rate Class based on the monthly Equivalent Bills for that Rate Class for the test period associated with the Incremental Approved Revenue. The Incremental RPC is approved by Order of the Commission in a proceeding other than a rate case that results in a permanent adjustment to base distribution rates. Such proceedings may include, but are not limited to, step adjustments, property tax reconciliation, and temporary rates.

v. Approved Revenue per Customer ("Approved RPC") is the sum of the Initial RPC per Rate Class and all Incremental RPC's per Rate Class, if any.

b. A separate RPC is calculated for each month of the decoupling year for each Rate Class using Approved Revenue and Equivalent Bills for each month.

c. The Initial RPC is set for each month by calculating the Initial Approved Revenue by Rate Class by month from the approved rate schedule rates by Rate Class for that month. The rate schedule rates adjusted for the MEP Premium are multiplied by the appropriate monthly billing units, Equivalent Bills for customer charges, therms for the blocked therm charges, to produce the Initial Approved Revenue by Rate Class by month. The monthly Initial Approved Revenue are then divided by the Equivalent Bills for that month to produce the Initial RPC's for each Rate Class. For the Initial RPC's, the Equivalent Bills and associated blocked therm billing units shall be adjusted by an End of Year Bill Adjustment that reflects the number of customers that received service at the end of the test year.

d. The Incremental RPC is set for each month by calculating the Incremental Approved Revenue by Rate Class by month from the approved rate schedule rates by Rate Class for that month. The rate schedule rates adjusted for the MEP Premium are multiplied by the appropriate monthly billing units, Equivalent Bills for customer charges, therms for the blocked therm charges, to produce the Incremental Approved Revenue by Rate Class by month. The monthly

Initial Approved Revenue are then divided by the Equivalent Bills for that month to produce the Initial RPC's for each. For the Incremental RPC's, the Equivalent Bills and associated blocked therm billing units shall be those bills and units for the test period associated with the Incremental Approved Revenue.

6. Calculation of Normal Weather Adjustment

a. Definitions.

i. Real-time normal weather adjustment is the difference between actual distribution revenue billed to each customer in each billing cycle for each month or portion thereof during the Winter Period, and what distribution revenue for each customer's bill would have been based on weather normalized therm deliveries for the same period. The resulting charge or credit will be added to or subtracted from each customer's bill at the time the bill is rendered (i.e., "real time").

ii. Winter Period. The time period from November 1 of a given year through April 30 of the following year inclusive.

iii. Base Load Factor for each customer is the customer's most recent two-year average daily delivered therms for actual bills rendered for those billing periods that are completely within the June 1 through August 31 calendar period excluding such billing periods that are only partially within the June 1 to August 31 period. If a customer has less than two-year's billing history, then the customer's available history for the months of June through August as defined above will be used to calculate the average daily delivered therms; and if a customer has no billing history for the months of June through August as defined above, then the average daily delivered therms for the calendar months of June through August for the rate schedule under which the customer is served will be used.

iv. Base Usage for each bill is the current Base Load Factor times the number of days in the billing period.

v. Heating Usage for each bill is the difference between the actual delivered therms for that bill less the Base Usage for that bill. If the calculated Heating Usage is less than zero, then the Heating Usage for that bill is set equal to zero.

vi. Heating Degree Days (HDD) for each day is sixty-five (65) minus the average temperature in degrees Fahrenheit for that day. If the calculated HDD is less than zero, then the HDD for that day is set equal to zero.

vii. Normal Heating Degree Days (Normal HDD) for each day is the thirty-year average HDD for that day.

viii. Normal Weather Adjustment Slope (NWA Slope) for each bill is the Heating Usage divided by the sum of actual HDD during the billing period.

ix. Normal Heating Usage for each bill is the NWA Slope times the sum of the Normal HDD for the billing period.

x. Normal Usage for each bill is the sum of the Base Usage and the Normal Heating Usage.

xi. Normal Weather Factor (NWF) for each bill is

$$\text{NWF} = \frac{\text{DeliveryCharge}_{\text{Normal}}}{\text{DeliveryCharge}_{\text{Actual}}} - 1$$

where Delivery Charge Normal is the calculated delivery charge for Normal Usage for the rate schedule applicable to that bill or portion thereof during the Winter Period and Delivery Charge Actual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

The Normal Weather Adjustment (NWA) for each bill is

$$\mathrm{NWA} = \mathrm{DeliveryCharge}_{\mathrm{Actual}} \times \mathrm{NWF}$$

where Delivery Charge Actual is the calculated delivery charge for actual delivered therms for the rate schedule applicable to that bill or portion thereof during the Winter Period.

7. Application of the NWA to Customer Bills

The NWA charge or credit will be separately stated, and added to or subtracted from each bill as applicable. Each bill will have a separate line titled "Normal Weather Adj.," which line will include the total variable distribution charges, the NWF percentage, and the resulting charge or credit.

8. Calculation of Revenue Decoupling Adjustment and Reconciliation
   a. Definitions
      i. Monthly Actual Distribution Revenue is the monthly billed Distribution Revenue less the MEP Premium for that month.
      ii. Monthly Allowed Revenue is the Approved RPC per Rate Class for the applicable month multiplied by the Actual Equivalent Bills for that month.
      iii. Forecasted Throughput Volume is the forecasted firm tariff throughput for a given Customer Group for the Billing Year.
      iv. Revenue Decoupling Accounts ("RDA Accounts") are the accounts established on the balance sheet for the purpose of recording the Revenue Decoupling Adjustment for each Customer Class Group.
   b. Description of Revenue Decoupling Adjustment and Reconciliation

Each month the Company will record a Revenue Decoupling Adjustment in the RDA Accounts in accordance with generally accepted accounting principles. The Revenue Decoupling Adjustment is the difference between the Monthly Allowed Revenue and the Monthly Actual Distribution Revenue. In addition, the reconciliation amounts collected or distributed through the RDAF are also recorded in the RDA Accounts for each Customer Class Group. The RDA Accounts accrue interest on the average monthly balance using the prime lending rate. At the conclusion of each Decoupling Year, the sum of the balance in each of the RDA Accounts for each Customer Class Group shall be used to determine the RDAF for the next Billing Year.

The RDAF to be applied to customers' bills in the Billing Year is the balance in the RDA Accounts at the end of the Decoupling Year for each Customer Class Group divided by the Forecasted Throughput Volume for that Customer Class Group.

9. Application of the RDAF to Customer Bills

The RDAF ($ per therm) shall be calculated annually for each Customer Group and shall be truncated at four decimal points per therm. The annual calculated Customer Group RDAF will be applied to the monthly firm tariff throughput for each customer in that particular Customer Group, effective November 1 of the given year.

10. Information to be Filed with the Commission

Information pertaining to the RDAF will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the LDAC. Such information shall include:

a. The calculation of the RDA Account Balance at the end of the Decoupling Year.
b. The calculation of the RDAF for the Decoupling Year by Customer Class Group to be applied to the upcoming Billing Year.
c. The approved calculation of the RDAF for the previous Billing Year by Customer Class Group.
d. The calculation for the each Commission Approved RPC and the associated Equivalent Bills for the Initial RPC and each Incremental RPC.

E. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

   The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

G. Recoverable Gas Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Gas Assistance Program (“GAP”). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying a GAP rate to all firm sales and transportation service throughput.

2. GAP Rate shall be applied to all firm sales and transportation tariff customers. The GAP Rate shall be filed with the Company’s Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company’s request for a change in the GAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. GAP Costs Allowable for LDAC: The costs to be recovered through the GAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the GAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced gas assistance program residential base rates, plus the GAP discount applied to the cost of gas, administrative, marketing and startup costs. The GAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. GAP Factor Formula

$$GAPF = \frac{GAP + A_{GAP}}{A: TPev}$$

where:

A: Tpev Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

GAP GAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{GAP} GAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 19(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the GAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the GAP classes to the difference in the regular and reduced residential base rates and cost of gas rates in effect for the annual reconciliation period and (2) the GAP discount applied to the cost of gas, start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred GAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$LDAC^x = CC^x + RDAF^x + ES + GREF^x + RCE + GAP$ and:

$ES^x = RHS + MGP$

where:

$LDAC^x$ = Annualized class specific LDAC.

CC^x = Annualized class specific CC or EE Charge.

$RDAF^x$ = Annualized class specific RDAF.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^x$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

GAP = Gas Assistance Program Rate

J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 19(B).

K. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.
2. Such amendments may include the addition or deletion of component cost categories, subject to the

review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

L. Amendments to Uniform System of Accounts

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(E).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 17(F).

1169-1756 **Gas Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the GAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 17(G).1168-1823 **Revenue Decoupling Adjustment Factor:** The RDA Accounts shall be used to record the difference between Actual Revenue and Allowed Revenue as well as the RDAF Revenue and associated interest as described in 17(D).

20 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

2. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

3. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

4. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

5. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

6. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

7. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

8. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not

include deliveries required to maintain plant production. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

I. Feedstock Gas: Is defined as natural gas used as a raw material for its chemical properties in creating an end product

J. Process Gas: Is defined as gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels

K. Boiler Fuel: Is considered to be natural gas used as a fuel for the generation of steam or electricity including the utilization of gas turbines for the generation of electricity

L. Alternate Fuel Capabilities: Is defined as a situation where an alternate fuel could have been utilized whether or not the facilities for such use have actually been installed, provided however, where the use of natural gas is for plant protection, feedstock or process uses and the only alternate fuel is propane or other gaseous fuel, then the consumer will be treated as if he had no alternate fuel capability.

M. POLICY

In the event that, due to gas supply restrictions or capacity constraints, the Company is unable to deliver the total requirements of its firm, sales or transportation rate customers, the available volumes of gas will be allocated to the Company's firm rate customers in accordance with the provisions of this policy. In the event that the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of the customer, customer shall be compensated for such emergency gas at the customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.

As curtailment becomes necessary through each succeeding category, the Company will implement full or partial curtailment of a customer, or by groups of customers, taking into consideration customer load characteristics, the Company's delivery system design and Company load characteristics in a manner which is believed to be in the best interests of customers in general.

N. PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories:

1. Company use for fuel and lost and unaccounted for

O. Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

P. Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

Q. Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

R. Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (6), or (7)

S. Firm sales or transportation service including the transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

T. Firm sales or transportation service including transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

U. STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

V. PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service.

II. RATE SCHEDULES

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1

Availability
This rate is available to all residential customers who do not have gas space heating equipment, who consume less than 80% of their normal usage in the six winter months of November through April and whose usage does not exceed 100 therms in any winter month. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.5130 per day or $15.39 per 30 day month
Winter Period:	All therms per 30 day month at $0.3844 per therm
Summer Period:	All therms per 30 day month at $0.3844 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

2 RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-3

Availability
This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.5130 per day or $15.39 per 30 day month
Winter Period:	All therms per 30 day month at $0.5632 per therm
Summer Period:	All therms per 30 day month at $0.5632 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

3 GAS ASSISTANCE PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4

Availability

This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Winter Customer Charge Per Meter:	$0.2823 per day or $8.47 per 30 day month
Winter Period:	All therms per 30 day month at $0.3098 per therm
Summer Customer Charge Per Meter:	$0.5130 per day or $15.39 per 30 day month
Summer Period:	All therms per 30 day month at $0.5632 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
For those customers qualifying for the program this rate R-4 shall apply for a six month winter period. On the date that the six month winter period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-gas assistance program Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following April 30, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Residential Non Heating Rate R-1.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.6670 per day or $20.01 per 30 day month
Winter Period:	All therms per 30 day month at $0.4997 per therm
Summer Period:	All therms per 30 day month at $0.4997 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program projects area who otherwise would have qualified for Residential Heating Rate R-3.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.6670 per day or $20.01 per 30 day month
Winter Period:	All therms per 30 day month at $0.7322 per therm
Summer Period:	All therms per 30 day month at $0.7322 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-3.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading an estimated bill will be rendered to the customer.Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

**6 MANAGED EXPANSION PROGRAM GAS ASSISTANCE PROGRAM RESIDENTIAL HEATING RATE:
CLASSIFICATION NO. R-7**

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Gas Assistance Program Residential Heating Rate R-4.

Qualified Programs:
a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Winter Customer Charge Per Meter:	$0.3670per day or $11.01 per 30 day month
Winter Period:	All therms per 30 day month at $0.4027 per therm
Summer Customer Charge Per Meter:	$.6670 per day or $20.01 per 30 day month
Summer Period:	All therms per 30 day month at $0.7322 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00

when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Gas Assistance Program Residential Heating Rate R-4.

For those customers qualifying for the program this rate R-7 shall apply for a six month winter period. On the date that the six month winter period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-7 expires, the rate on each account shall revert back to the non-gas assistance program Residential Heating Rate, R-6. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following April 30, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

7 COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-41

Availability

This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.9020 per day or $57.06 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.4688 per therm
	All over 100 therms per 30 day month at $0.3149 per therm
Summer Period:	First 20* therms per 30 day month at $0.4688 per therm
	All over 20 therms per 30 day month at $0.3149 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$5.7063 per day or $171.19 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.4261 per therm
	All over 1000 therms per 30 day month at $0.2839 per therm
Summer Period:	First 400* therms per 30 day month at $0.4261 per therm
	All over 400 therms per 30 day month at $0.2839 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$24.4897 per day or $734.69 per 30 day month
Winter Period:	All therms per 30 day month at $0.2620 per therm
Summer Period:	All therms per 30 day month at $0.1198 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44

Availability
This rate is Mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-41.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4727 per day or $74.18 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.6094 per therm
	All over 100 therms per 30 day month at $0.4094 per therm
Summer Period:	First 20* therms per 30 day month at $0.6094 per therm
	All over 20 therms per 30 day month at $0.4094 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-41.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-42.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$7.4183 per day or $222.55 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.5539 per therm
	All over 1000 therms per 30 day month at $0.3691 per therm
Summer Period:	First 400* therms per 30 day month at $0.5539 per therm
	All over 400 therms per 30 day month at $0.3691 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-42.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-43.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$31.8367 per day or $955.10 per 30 day month
Winter Period:	All therms per 30 day month at $0.3406 per therm
Summer Period:	All therms per 30 day month at $0.1557 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-43.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

13 COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.9020 per day or $57.06 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2819 per therm
	All over 100 therms per 30 day month at $0.1833 per therm
Summer Period:	First 100* therms per 30 day month at $0.2819 per therm
	All over 100 therms per 30 day month at $0.1833 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this

tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-52

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$5.7063 per day or $171.19 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.2428 per therm
	All over 1000 therms per 30 day month at $0.1617 per therm
Summer Period:	First 1000* therms per 30 day month at $0.1749 per therm
	All over 1000 therms per 30 day month at $0.1000 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFICATION NO. G-53

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$25.2033 per day or $756.10 per 30 day month
Winter Period:	All therms per 30 day month at $0.1697 per therm
Summer Period:	All therms per 30 day month at $0.0814 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-54

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$25.2033 per day or $756.10 per 30 day month
Winter Period:	All therms per 30 day month at $0.0648 per therm
Summer Period:	All therms per 30 day month at $0.0352 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 90 or 91 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly,

daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-55

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-51.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4727 per day or $74.18 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.3665 per therm
	All over 100 therms per 30 day month at $0.2383 per therm
Summer Period:	First 100* therms per 30 day month at $0.3665 per therm
	All over 100 therms per 30 day month at $0.2383 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-51.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-56

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-52.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$7.4183 per day or $222.55 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.3157 per therm
	All over 1000 therms per 30 day month at $0.2102 per therm
Summer Period:	First 1000* therms per 30 day month at $0.2287 per therm
	All over 1000 therms per 30 day month at $0.1300 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-52.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFICATION NO. G-57

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-53.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$32.7643 per day or $982.93 per 30 day month
Winter Period:	All therms per 30 day month at $0.2207 per therm
Summer Period:	All therms per 30 day month at $0.1059 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer

in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-53.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

20 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-58

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-54.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$32.7643 per day or $982.93 per 30 day month
Winter Period:	All therms per 30 day month at $0.0842 per therm
Summer Period:	All therms per 30 day month at $0.0457 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 92 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-54.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

21 OUTDOOR GAS LIGHTING

Availability
This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services. Service under this rate is available at those locations which were receiving service hereunder as of July 1, 2015, and which have continuously received service hereunder since that date.

Rate Per Light Per Month	$12.81

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

22 FIRM RATE SCHEDULES - EXCLUDING KEENE CUSTOMERS

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Rates effective November 01, 2021 - April 30, 2022 Winter Period				Rates Effective August 1, 2021 - October 31, 2021 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
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
All Therms	$ 0.3844	$ 0.6050	$ 0.0589	$ 1.0483	$ 0.3844	$ 0.3935	$ 0.0589	$ 0.8368
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
Size of the first block	All Therms				All Therms			
All Therms	$ 0.5632	$ 0.6050	$ 0.0589	$ 1.2271	$ 0.5632	$ 0.3935	$ 0.0589	$ 1.0156
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 8.47			$ 8.47	$ 15.39			$ 15.39
Size of the first block	All Therms				All Therms			
All Therms	$ 0.3098	$ 0.3328	$ 0.0589	$ 0.7015	$ 0.5632	$ 0.3935	$ 0.0589	$ 1.0156
Commercial/Industrial - G-41								
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	$ 0.6031	$ 0.0555	$ 1.1274	$ 0.4688	$ 0.3886	$ 0.0555	$ 0.9129
All therms over the first block per month at	$ 0.3149	$ 0.6031	$ 0.0555	$ 0.9735	$ 0.3149	$ 0.3886	$ 0.0555	$ 0.7590
Commercial/Industrial - G-42								
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	$ 0.6031	$ 0.0555	$ 1.0847	$ 0.4261	$ 0.3886	$ 0.0555	$ 0.8702
All therms over the first block per month at	$ 0.2839	$ 0.6031	$ 0.0555	$ 0.9425	$ 0.2839	$ 0.3886	$ 0.0555	$ 0.7280
Commercial/Industrial - G-43								
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	$ 0.6031	$ 0.0555	$ 0.9206	$ 0.1198	$ 0.3886	$ 0.0555	$ 0.5639
Commercial/Industrial - G-51								
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	$ 0.6139	$ 0.0555	$ 0.9513	$ 0.2819	$ 0.3999	$ 0.0555	$ 0.7373
All therms over the first block per month at	$ 0.1833	$ 0.6139	$ 0.0555	$ 0.8527	$ 0.1833	$ 0.3999	$ 0.0555	$ 0.6387
Commercial/Industrial - G-52								
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	$ 0.6139	$ 0.0555	$ 0.9122	$ 0.1759	$ 0.3999	$ 0.0555	$ 0.6313
All therms over the first block per month at	$ 0.1617	$ 0.6139	$ 0.0555	$ 0.8311	$ 0.1000	$ 0.3999	$ 0.0555	$ 0.5554
Commercial/Industrial - G-53								
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	$ 0.6139	$ 0.0555	$ 0.8391	$ 0.0814	$ 0.3999	$ 0.0555	$ 0.5368
Commercial/Industrial - G-54								
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	$ 0.6139	$ 0.0555	$ 0.7342	$ 0.0352	$ 0.3999	$ 0.0555	$ 0.4906

DATED: August 13, 2021 ISSUED BY: /s/Neil Proudman
Neil Proudman
EFFECTIVE: August 1, 2021 TITLE: President

Authorized by NHPUC Order No. 26,505 dated July 30, 2021, in Docket No. DG 20-105

23 FIRM RATE SCHEDULES - KEENE CUSTOMERS

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Rates effective November 01, 2021 - April 30, 2022 Winter Period Period				Rates Effective August 1, 2021 - October 31, 2021 Summer Period			
	Delivery Charge	Cost of Gas Rate Page 97	LDAC Page 101	Total Rate	Delivery Charge	Cost of Gas Rate Page 93	LDAC Page 101	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
All Therms	$ 0.3844	$ 0.9492	$ 0.0589	$ 1.3925	$ 0.3844	$ 1.4680	$ 0.0589	$ 1.9113
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
Size of the first block	All Therms				All Therms			
	$ 0.5632	$ 0.9492	$ 0.0589	$ 1.5713	$ 0.5632	$ 1.4680	$ 0.0589	$ 2.0901
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 8.47			$ 8.47	$ 15.39			$ 15.39
Size of the first block	All Therms				All Therms			
	$ 0.3098	$ 0.9492	$ 0.0589	$ 1.3179	$ 0.5632	$ 1.4680	$ 0.0589	$ 2.0901
Commercial/Industrial - G-41								
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	$ 0.9492	$ 0.0555	$ 1.4735	$ 0.4688	$ 1.4680	$ 0.0555	$ 1.9923
All therms over the first block per month at	$ 0.3149	$ 0.9492	$ 0.0555	$ 1.3196	$ 0.3149	$ 1.4680	$ 0.0555	$ 1.8384
Commercial/Industrial - G-42								
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	$ 0.9492	$ 0.0555	$ 1.4308	$ 0.4261	$ 1.4680	$ 0.0555	$ 1.9496
All therms over the first block per month at	$ 0.2839	$ 0.9492	$ 0.0555	$ 1.2886	$ 0.2839	$ 1.4680	$ 0.0555	$ 1.8074
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$ 734.69			$ 734.69	$ 734.69			$ 734.69
All therms	$ 0.2620	$ 0.9492	$ 0.0555	$ 1.2667	$ 0.1198	$ 1.4680	$ 0.0555	$ 1.6433
Commercial/Industrial - G-51								
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	$ 0.9492	$ 0.0555	$ 1.2866	$ 0.2819	$ 1.4680	$ 0.0555	$ 1.8054
All therms over the first block per month at	$ 0.1833	$ 0.9492	$ 0.0555	$ 1.1880	$ 0.1833	$ 1.4680	$ 0.0555	$ 1.7068
Commercial/Industrial - G-52								
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	$ 0.9492	$ 0.0555	$ 1.2475	$ 0.1759	$ 1.4680	$ 0.0555	$ 1.6994
All therms over the first block per month at	$ 0.1617	$ 0.9492	$ 0.0555	$ 1.1664	$ 0.1000	$ 1.4680	$ 0.0555	$ 1.6235
Commercial/Industrial - G-53								
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	$ 0.9492	$ 0.0555	$ 1.1744	$ 0.0814	$ 1.4680	$ 0.0555	$ 1.6049
Commercial/Industrial - G-54								
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	$ 0.9492	$ 0.0555	$ 1.0695	$ 0.0352	$ 1.4680	$ 0.0555	$ 1.5587

24 FIRM RATE SCHEDULES - MANAGED EXPANSION PROGRAM-EXCLUDING KEENE CUSTOMERS

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Rates effective November 01, 2021 - April 30, 2022 Winter Period				Rates Effective August 1, 2021 - October 31, 2021 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
Residential Non Heating - R-5								
Customer Charge per Month per Meter	$ 20.01			$ 20.01	$ 20.01			$ 20.01
All Therms	$ 0.4997	$ 0.6050	$ 0.0589	$ 1.1636	$ 0.4997	$ 0.3935	$ 0.0589	$ 0.9521
Residential Heating - R-6								
Customer Charge per Month per Meter	$ 20.01			$ 20.01	$ 20.01			$ 20.01
Size of the first block	all therms				all therms			
Therms in the first block per month at	$ 0.7322	$ 0.6050	$ 0.0589	$ 1.3961	$ 0.7322	$ 0.3935	$ 0.0589	$ 1.1846
Residential Heating - R-7								
Customer Charge per Month per Meter	$ 11.01			$ 11.01	$ 20.01			$ 20.01
Size of the first block	all therms				all therms			
Therms in the first block per month at	$ 0.4027	$ 0.6050	$ 0.0589	$ 1.0666	$ 0.7322	$ 0.3935	$ 0.0589	$ 1.1846
Commercial/Industrial - G-44								
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	$ 0.6031	$ 0.0555	$ 1.2680	$ 0.6094	$ 0.3886	$ 0.0555	$ 1.0535
All therms over the first block per month at	$ 0.4094	$ 0.6031	$ 0.0555	$ 1.0680	$ 0.4094	$ 0.3886	$ 0.0555	$ 0.8535
Commercial/Industrial - G-45								
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	$ 0.6031	$ 0.0555	$ 1.2125	$ 0.5539	$ 0.3886	$ 0.0555	$ 0.9980
All therms over the first block per month at	$ 0.3691	$ 0.6031	$ 0.0555	$ 1.0277	$ 0.3691	$ 0.3886	$ 0.0555	$ 0.8132
Commercial/Industrial - G-46								
Customer Charge per Month per Meter	$ 955.10			$ 955.10	$ 955.10			$ 955.10
All therms over the first block per month at	$ 0.3406	$ 0.6031	$ 0.0555	$ 0.9992	$ 0.1557	$ 0.3886	$ 0.0555	$ 0.5998
Commercial/Industrial - G-55								
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	$ 0.6139	$ 0.0555	$ 1.0359	$ 0.3665	$ 0.3999	$ 0.0555	$ 0.8219
All therms over the first block per month at	$ 0.2383	$ 0.6139	$ 0.0555	$ 0.9077	$ 0.2383	$ 0.3999	$ 0.0555	$ 0.6937
Commercial/Industrial - G-56								
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	$ 0.6139	$ 0.0555	$ 0.9851	$ 0.2287	$ 0.3999	$ 0.0555	$ 0.6841
All therms over the first block per month at	$ 0.2102	$ 0.6139	$ 0.0555	$ 0.8796	$ 0.1300	$ 0.3999	$ 0.0555	$ 0.5854
Commercial/Industrial - G-57								
Customer Charge per Month per Meter	$ 982.93			$ 982.93	$ 982.93			$ 982.93
All therms over the first block per month at	$ 0.2207	$ 0.6139	$ 0.0555	$ 0.8901	$ 0.1059	$ 0.3999	$ 0.0555	$ 0.5613
Commercial/Industrial - G-58								
Customer Charge per Month per Meter								
All therms over the first block per month at	$ 982.93			$ 982.93	$ 982.93			$ 982.93
	$ 0.0842	$ 0.6139	$ 0.0555	$ 0.7536	$ 0.0457	$ 0.3999	$ 0.0555	$ 0.5011

Firm Rate Schedule

25 FIRM RATE SCHEDULES – OUTDOOR GAS LIGHTING

Outdoor Gas Lighting	
Per Light Per Month	$12.81

26 ANTCIPATED SUMMER PERIOD COST OF GAS EXCLUDING KEENE CUSTOMERS OR GAS LIGHTING

Anticipated Cost of Gas

PERIOD COVERED: SUMMER PERIOD, MAY 1, 2021 THROUGH OCTOBER 31, 2021
(REFER TO TEXT IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 2,868,280	
Supply Costs:	4,387,278	
Storage Gas:		
Demand, Capacity:	$ -	
Commodity Costs:	-	
Produced Gas:	$ 29,014	
Hedged Contract (Savings)/Loss	$ -	
Unadjusted Anticipated Cost of Gas		$ 7,284,571
Adjustments:		
Prior Period (Over)/Under Recovery (as of April 30, 2019)	$ 105,886	
Interest	(3,492)	
Prior Period Adjustments	-	
Broker Revenues	-	
Refunds from Suppliers	-	
Fuel Financing	-	
Transportation CGA Revenues	-	
Interruptible Sales Margin	-	
Capacity Release Margin	-	
Hedging Costs	-	
Fixed Price Option Administrative Costs	-	
Total Adjustments		102,394
Total Anticipated Direct Cost of Gas		$ 7,386,965
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Unadjusted Anticipated Cost of Gas 05/01/19 - 10/31/19)	$ 7,284,571	
Working Capital Rate - Lead Lag Days / 365	0.0391	
Prime Rate	3.25%	
Working Capital Percentage	0.127%	
Working Capital	$ 9,258	
Plus: Working Capital Reconciliation (Acct 1163-1424)	(13,709)	
Total Working Capital Allowance		$ (4,451)
Bad Debt:		
Total Unadjusted Anticipated Cost of Gas 05/01/19 - 10/31/19)	$ 7,284,571	
Less: Refunds	-	
Plus: Total Working Capital	(4,451)	
Plus: Prior Period (Over)/Under Recovery	105,886	
Subtotal	$ 7,386,006	
Bad Debt Percentage	1.11%	
Bad Debt Allowance	$ 81,985	
Plus: Bad Debt Reconciliation (Acct 1163-1754)	(326,326)	
Total Bad Debt Allowance		(244,341)
Production and Storage Capacity		-
Miscellaneous Overhead (05/01/19 - 10/31/19)	$ 13,170	
Times Summer Sales	22,004	
Divided by Total Sales	111,369	
Miscellaneous Overhead		2,602
Total Anticipated Indirect Cost of Gas		$ (246,190)
Total Cost of Gas		$ 7,140,775

DATED: August 13, 2021 — ISSUED BY: /s/Neil Proudman
Neil Proudman
EFFECTIVE: August 1, 2021 — TITLE: President

Authorized by NHPUC Order No. 26,505 dated July 30, 2021, in Docket No. DG 20-105

27 CALCULATION OF FIRM SALES SUMMER PERIOD COST OF GAS RATE EXCLUDING KEENE CUSTOMERS

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2021 THROUGH OCTOBER 31, 2021
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)	(Col 3)
Total Anticipated Direct Cost of Gas		$ 7,386,966	
Projected Prorated Sales (05/01/20 - 10/31/20)		22,681,422	
Direct Cost of Gas Rate			$ 0.3257 per therm
Demand Cost of Gas Rate		$ 2,868,280	$ 0.1265 per therm
Commodity Cost of Gas Rate		4,416,292	$ 0.1947 per therm
Adjustment Cost of Gas Rate		102,394	$ 0.0045 per therm
Total Direct Cost of Gas Rate		$ 7,386,966	$ 0.3257 per therm
Total Anticipated Indirect Cost of Gas		$ (246,190)	
Projected Prorated Sales (05/01/20 - 10/31/20)		22,681,422	
Indirect Cost of Gas			$ (0.0109) per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21			**$ 0.3148 per therm**

RESIDENTIAL COST OF GAS RATE - 05/01/2021 Approved in Order No 26,419 in DG 20-141	**COGsr**	**$ 0.3148 /therm**
Change in rate due to change in under/over recovery		**$ 0.0787**
RESIDENTIAL COST OF GAS RATE - 05/01/2021	**COGsr**	**$ 0.3935 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 06/01/2021	**COGsr**	**$ 0.3935 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 07/01/2021	**COGsr**	**$ 0.3935 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 08/01/2021	**COGsr**	**$ 0.3935 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 09/01/2021	**COGsr**	**$ 0.3935 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 10/01/2021	**COGsr**	**$ 0.3935 /therm**

Maximum (COG + 25%) $ 0.3935

COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2021 Approved in Order No 26,419 in DG 20-141	**COGsl**	**$ 0.3199 /therm**
Change in rate due to change in under/over recovery		**$ 0.0800**
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2021	**COGsl**	**$ 0.3999 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND LOW WINTER USE COST OF GAS RATE - 06/01/2021	**COGsl**	**$ 0.3999 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND LOW WINTER USE COST OF GAS RATE - 07/01/2021	**COGsl**	**$ 0.3999 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND LOW WINTER USE COST OF GAS RATE - 08/01/2021	**COGsl**	**$ 0.3999 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND LOW WINTER USE COST OF GAS RATE - 09/01/2021	**COGsl**	**$ 0.3999 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND LOW WINTER USE COST OF GAS RATE - 10/01/2021	**COGsl**	**$ 0.3999 /therm**

Average Demand Cost of Gas Rate Effective 05/01/20	$ 0.1265		
'Times: Low Winter Use Ratio (Summer)	1.0620	Maximum (COG + 25%)	$ 0.3999
Times: Correction Factor	0.9798		
Adjusted Demand Cost of Gas Rate	$ 0.1316		
Commodity Cost of Gas Rate	$ 0.1947		
Adjustment Cost of Gas Rate	0.0045		
Indirect Cost of Gas Rate	(0.0109)		
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.3199		

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2021	**COGsh**	**$ 0.3109 /therm**
Change in rate due to change in under/over recovery		**$ 0.0777**
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2021	**COGsh**	**$ 0.3886 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND HIGH WINTER USE COST OF GAS RATE - 06/01/2021	**COGsh**	**$ 0.3886 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND HIGH WINTER USE COST OF GAS RATE - 07/01/2021	**COGsl**	**$ 0.3886 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND HIGH WINTER USE COST OF GAS RATE - 08/01/2021	**COGsl**	**$ 0.3886 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND HIGH WINTER USE COST OF GAS RATE - 09/01/2021	**COGsl**	**$ 0.3886 /therm**
Change in rate due to change in under/over recovery		**$ -**
COM/IND HIGH WINTER USE COST OF GAS RATE - 10/01/2021	**COGsl**	**$ 0.3886 /therm**

Average Demand Cost of Gas Rate Effective 05/01/20	$ 0.1265		
'Times: High Winter Use Ratio (Summer)	0.9890	Maximum (COG + 25%)	$ 0.3886
Times: Correction Factor	0.9798		
Adjusted Demand Cost of Gas Rate	$ 0.1226		
Commodity Cost of Gas Rate	$ 0.1947		
Adjustment Cost of Gas Rate	0.0045		
Indirect Cost of Gas Rate	(0.0109)		
Adjusted Com/Ind High Winter Use Cost of Gas Rate	$ 0.3109		

28 CALCULATION OF SUMMER PERIOD COST OF GAS RATE – KEENE CUSTOMERS

Period Covered: Summer Period May 1, 2021, through October 31, 2021

Projected Gas Sales - therms			311,740
Total Anticipated Cost of Sendout			$391,714
Add:	Prior Period Deficiency Uncollected	$0	
	Interest	$0	
Deduct:	Prior Period Excess Collected	($23,223)	
	Interest	$18	
	Prior Period Adjustments and Interest		($23,205)
Total Anticipated Cost			$368,509
Cost of Gas Rate - Beginning Period (per therm)			$1.1821
Mid Period Adjustment - June 1, 2021			$0.0844
Mid Period Adjustment - July 1, 2021			$0.2015
Mid Period Adjustment - August 1, 2021			
Mid Period Adjustment - September 1, 2021			
Mid Period Adjustment - October 1, 2021			
Revised Cost of Gas Rate - Effective July 1, 2021 (per therm)			$1.4680

Pursuant to tariff section 17(d), the Company may adjust the approved cost of gas rate upward on a monthly basis to the following rate:

Maximum Cost of Gas Rate (per therm)	$1.4776

29 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE EXCLUDING KEENE CUSTOMERS

II. RATE SCHEDULES
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021
(Refer to Text in Section 17(A) Fixed Price Option Program)

	(Col 1)	(Col 2)		(Col 3)	
1	Total Anticipated Direct Cost of Gas	$46,922,854			
2	Projected Prorated Sales (11/01/20 - 04/30/21)	88,213,529			
3	**Direct Cost of Gas Rate**		$	0.5319	per therm
4	**Demand Cost of Gas Rate**	$12,978,688	$	0.1471	per therm
5	**Commodity Cost of Gas Rate**	32,931,719	$	0.3733	per therm
6	**Adjustment Cost of Gas Rate**	1,012,447	$	0.0115	per therm
7	**Total Direct Cost of Gas Rate**	$46,922,854	$	0.5319	per therm
8	Total Anticipated Indirect Cost of Gas	$ 2,220,114			
9	Projected Prorated Sales (11/01/20 - 04/30/21)	88,213,529			
10	**Indirect Cost of Gas**		$	0.0252	per therm
11	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/19)**		**$**	**0.5571**	
12	**Calculation of FPO Excluding Low Income - Rate Code R-3**				
13	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/19)**		**$**	**0.5571**	
14	**FPO Risk Premium**		$	0.0200	
15	**TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE (11/01/19)**		**$**	**0.5771**	
16	**RESIDENTIAL COST OF GAS RATE - EXCLUDING LOW INCOME - (R-3) 11/01/20**	**COGwr**	**$**	**0.5771**	**/therm**
17	**Calculation of FPO for Gas Assistance Program - Rate Code R-4**				
18	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/20) FPO (Line 13 * 0.55)**		**$**	**0.3064**	
19	**FPO Risk Premium (Line 14 * 0.55)**		$	0.0110	
20	**TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE (11/01/19) (Line 15 * 0.55)**		**$**	**0.3174**	
21	**RESIDENTIAL COST OF GAS RATE - LOW INCOME - (R-4) 11/01/20**	**COGwr**	**$**	**0.3174**	**/therm**

30 CALCULATION OF FIRM SALES WINTER PERIOD COST OF GAS RATE - EXCLUDING KEENE CUSTOMERS

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)	(Col 3)
Total Anticipated Direct Cost of Gas		$ 46,922,854	
Projected Prorated Sales (11/01/2020 - 04/30/21)		88,213,529	
Direct Cost of Gas Rate			$ 0.5319 per therm
Demand Cost of Gas Rate		$ 12,978,688	$ 0.1471 per therm
Commodity Cost of Gas Rate		32,931,719	$ 0.3733 per therm
Adjustment Cost of Gas Rate		1,012,447	$ 0.0115 per therm
Total Direct Cost of Gas Rate		$ 46,922,854	$ 0.5319 per therm
Total Anticipated Indirect Cost of Gas		$ 2,220,114	
Projected Prorated Sales (11/01/20 - 04/30/21)		88,213,529	
Indirect Cost of Gas			$ 0.0252 per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/20			**$ 0.5571 per therm**

RESIDENTIAL COST OF GAS RATE - EXCLUDING LOW INCOME - 11/01/20	**COGwr**	**$ 0.5571 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 12/01/2020	**COGsr**	**$ 0.5571 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0907)**
RESIDENTIAL COST OF GAS RATE - 01/01/2021	**COGwr**	**$ 0.4664 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0388)**
RESIDENTIAL COST OF GAS RATE - 02/01/2021	**COGwr**	**$ 0.4276 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0880**
RESIDENTIAL COST OF GAS RATE - 03/01/2021	**COGwr**	**$ 0.5156 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0894**
RESIDENTIAL COST OF GAS RATE - 04/01/2021	**COGwr**	**$ 0.6050 /therm**
	Maximum (COG + 25%)	$ 0.6964

GAS ASSISTANCE PLAN RESIDENTIAL COST OF GAS RATE R-4 - 11/01/20	**COGwr**	**$ 0.3064 /therm**
Change in rate due to change in under/over recovery		**$ -**
RESIDENTIAL COST OF GAS RATE - 12/01/2020	**COGsr**	**$ 0.3064 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0499)**
RESIDENTIAL COST OF GAS RATE - 01/01/2021	**COGwr**	**$ 0.2565 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0213)**
RESIDENTIAL COST OF GAS RATE - 2/1/2021	**COGwr**	**$ 0.2352 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0484**
RESIDENTIAL COST OF GAS RATE - 3/1/2021	**COGwr**	**$ 0.2836 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0492**
RESIDENTIAL COST OF GAS RATE - 4/1/2021	**COGwr**	**$ 0.3328 /therm**
	Maximum (COG + 25%)	$ 0.3830

C&I LOW WINTER USE COST OF GAS RATE - 11/01/20	**COGwl**	**$ 0.5660 /therm**
Change in rate due to change in under/over recovery		**$ -**
C&I LOW WINTER USE COST OF GAS RATE - 12/01/2020	**COGsl**	**$ 0.5660 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0907)**
C&I LOW WINTER USE COST OF GAS RATE - 01/01/2021	**COGsl**	**$ 0.4753 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0388)**
C&I LOW WINTER USE COST OF GAS RATE - 2/01/2021	**COGsl**	**$ 0.4365 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0880**
C&I LOW WINTER USE COST OF GAS RATE - 3/01/2021	**COGsl**	**$ 0.5245 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0894**
C&I LOW WINTER USE COST OF GAS RATE - 4/01/2021	**COGsl**	**$ 0.6139 /therm**

Average Demand Cost of Gas Rate Effective 11/01/20	$ 0.1471		
Times: Low Winter Use Ratio (Winter)	1.0620	Maximum (COG + 25%)	$ 0.7075
Times: Correction Factor	0.9984		
Adjusted Demand Cost of Gas Rate	$ 0.1560		
Commodity Cost of Gas Rate	$ 0.3733		
Adjustment Cost of Gas Rate	$ 0.0115		
Indirect Cost of Gas Rate	$ 0.0252		
Adjusted C&I Low Winter Use Cost of Gas Rate	$ 0.5660		

C&I HIGH WINTER USE COST OF GAS RATE - 11/01/20	**COGwh**	**$ 0.5552 /therm**
Change in rate due to change in under/over recovery		**$ -**
C&I HIGH WINTER USE COST OF GAS RATE - 12/01/2020	**COGsh**	**$ 0.5552 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0907)**
C&I HIGH WINTER USE COST OF GAS RATE - 01/01/2021	**COGwh**	**$ 0.4645 /therm**
Change in Rate due to change in under/over recovery		**$ (0.0388)**
C&I HIGH WINTER USE COST OF GAS RATE - 2/01/2021	**COGwh**	**$ 0.4257 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0880**
C&I HIGH WINTER USE COST OF GAS RATE - 3/01/2021	**COGwh**	**$ 0.5137 /therm**
Change in Rate due to change in under/over recovery		**$ 0.0894**
C&I HIGH WINTER USE COST OF GAS RATE - 4/01/2021	**COGwh**	**$ 0.6031 /therm**

Average Demand Cost of Gas Rate Effective 11/01/20	$ 0.1471		
Times: High Winter Use Ratio (Winter)	0.9890	Maximum (COG + 25%)	$ 0.6941
Times: Correction Factor	0.9984		
Adjusted Demand Cost of Gas Rate	$ 0.1452		
Commodity Cost of Gas Rate	$ 0.3733		
Adjustment Cost of Gas Rate	$ 0.0115		
Indirect Cost of Gas Rate	$ 0.0252		
Adjusted C&I High Winter Use Cost of Gas Rate	$ 0.5552		

31. ANTICIPATED COST OF GAS - EXCLUDING KEENE CUSTOMERS

Anticipated Cost of Gas

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)		(Col 2)		(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	$	12,022,922		
Supply Costs:		28,276,980		
Storage Gas:				
Demand, Capacity:	$	955,766		
Commodity Costs:		3,064,149		
Produced Gas:		1,590,589		
Hedged Contract (Saving)/Loss		-		
Hedge Underground Storage Contract (Saving)/Loss		-		
Unadjusted Anticipated Cost of Gas			$	45,910,407
Adjustments:				
Prior Period (Over)/Under Recovery (as of 05/01/20)	$	2,227,421		
Interest		72,812		
Fuel Inventory Revenue Requirement		441,037		
Broker Revenues		(32,725)		
Refunds from Suppliers		-		
Fuel Financing		-		
Transportation CGA Revenues		(4,516)		
Interruptible Sales Margin		-		
Capacity Release and Off System Sales Margins		(1,736,581)		
Hedging Costs		-		
Fixed Price Option Administrative Costs		45,000		
Total Adjustments				1,012,447
Total Anticipated Direct Cost of Gas			$	46,922,854
Anticipated Indirect Cost of Gas				
Working Capital:				
Total Unadjusted Anticipated Cost of Gas 11/01/20 - 04/30/21	$	45,910,407		
Working Capital Rate: Lead Lag Days / 365		0.0391		
Prime Rate		3.25%		
Working Capital Percentage		0.127%		
Working Capital	$	58,347		
Plus: Working Capital Reconciliation (Acct 142.20)		(66,837)		
Total Working Capital Allowance				(8,490)
Bad Debt:				
Total Unadjusted Anticipated Cost of Gas 11/01/20 - 04/30/21	$	45,910,407		
Less: Refunds		-		
Plus: Total Working Capital		(8,490)		
Plus: Prior Period (Over)/Under Recovery		2,227,421		
Subtotal	$	48,129,338		
Bad Debt Percentage		1.11%		
Bad Debt Allowance	$	534,236		
Plus: Bad Debt Reconciliation (Acct 175.52)		(296,628)		
Total Bad Debt Allowance			$	237,608
Production and Storage Capacity			$	1,980,428
Miscellaneous Overhead 11/01/20 - 04/30/21	$	13,170		
Times Winter Sales		89,365		
Divided by Total Sales		111,369		
Miscellaneous Overhead				10,568
Total Anticipated Indirect Cost of Gas			$	2,220,114
Total Cost of Gas			$	49,142,968

32. CALCULATION OF FIRM SALES AND FIXED WINTER PERIOD COST OF GAS RATE - KEENE CUSTOMERS

Calculation of the Cost of Gas Rate

Period Covered: Winter Period November 1, 2020 through April 30, 2021

Projected Gas Sales - therms			1,108,419	
Total Calculated Cost of Gas Sendout			$1,310,950	
CNG Costs Not Included In Cost of Gas Rate			($204,754)	
Total Anticipated Cost of Gas Sendout			$1,106,196	
Add:	Prior Period Deficiency Uncollected	$30,171		
	Interest	$136		
Deduct:	Prior Period Excess Collected	$0		
	Interest	$0		
	Prior Period Adjustments and Interest		$30,307	
Total Anticipated Cost			$1,136,503	
Costs Adjusted per Order No. 26,428 in Docket No. DG 20-152 dated December 02, 2020				
Cost of Gas Rate			Excluding Gas Assistance Program	Gas Assistance Program
Non-Fixed Price Option Cost of Gas Rate - Beginning Period (per therm)			$1.0253	$0.5639
Mid Period Adjustment - December 01, 2020			$0.0000	$0.0000
Mid Period Adjustment - January 01, 2021			($0.0283)	($0.0156)
Mid Period Adjustment - February 01, 2021			($0.0042)	($0.0023)
Mid Period Adjustment - March 01, 2021			$0.0000	$0.0000
Mid Period Adjustment - April 01, 2021			$0.2888	$0.1588
Revised Non-Fixed Price Option Cost of Gas Rate - Effective April 1, 2021 (per therm)			$1.2816	$0.7048
Fixed Price Option Cost of Gas Rate (per therm) November 2020			$1.2300	$0.6765
Fixed Price Option Cost of Gas Rate (per therm) December 2020-April 2021			$1.0277	$0.5652

Pursuant to tariff section 17(d), the Company may adjust the approved cost of gas rate upward on a monthly basis to the following rate:

Maximum Cost of Gas Rate - Non-Fixed Price Option (per therm)	$1.2816	$0.7049

33. CALCULATION OF FIRM TRANSPORTATION COST OF GAS RATE

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021
(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	(Col 2)		(Col 3)		(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:					
PROPANE	$ 568,511				
LNG	1,022,078				
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	1,590,589				
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	8.7%				
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	$ 138,381				
PROJECTED FIRM THROUGHPUT (THERMS):					
FIRM SALES	89,364,968		67.8%		
FIRM TRANSPORTATION SUBJECT TO FTCG	42,456,275		32.2%		
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	131,821,243		100.0%		
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	32.2%	x	$ 138,381	=	$ 44,569
PRIOR (OVER) OR UNDER COLLECTION					(40,053)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS					$ 4,516
PROJECTED FIRM TRANSPORTATION THROUGHPUT					42,456,275
FIRM TRANSPORTATION COST OF GAS					$ 0.0001

34. ENVIRONMENTAL SURCHARGE - MANUFACTURED GAS PLANTS

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants		
Required Annual Environmental Increase	$2,864,179	
First one-third of prior period under recoveries (through June 2019)	$341,389	
July 2019 - June 2020 recovery difference between actual and estimate	$338,564	
Environmental Subtotal	$3,544,132	
Overall Annual Net Increase to Rates	$3,544,132	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/20 - sales and transportation	179,574,679	therms
Surcharge per therm	$0.0197	per therm
Total Environmental Surcharge	$0.0197	

DATED: August 13, 2021
EFFECTIVE: August 1, 2021

ISSUED BY: /s/Neil Proudman
Neil Proudman
TITLE: President

Authorized by NHPUC Order No. 26,505 dated July 30, 2021, in Docket No. DG 20-105

35 RATE CASE EXPENSE AND RECOUPMENT FACTOR CALCULATION

Liberty Utilities (Energy North 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, 2020 - October 31, 2021

Rate Case Expense Remaining from Docket No. DG 17-048	$87,069
Recoupment Remaining from Docket No. DG 17-048	$0
July 1, 2020 Balance	$87,069
Plus Estimated Interest from July 2020 through October 2020	$745
Minus Estimated Recoveries from July 2020 through October 2020	($43,733)
Total Estimated Remaining Recovery As of November 1, 2020	$44,081
Estimated November 2019 - October 2020 Interest	$538
Total Remaining Recovery	$44,619
Estimated November 2020 - October 2021 Sales (therms)	179,574,679
RCE & Recoupment rate per therm November 2020 - October 2021	$0.0002

36 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION

Local Delivery Adjustment Charge Calculation

		Sales Customers	Transportation Customers	
Residential Non Heating Rates - R-1, R-5				
Energy Efficiency Charge	$ 0.0831			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$ 0.0831		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0197			
Environmental Surcharge (ES)		0.0197		
Revenue Decoupling Adjustment Factor (RDAF)		(0.0562)		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0000		
Rate Case Expense Factor (RCEF)		0.0002		
Gas Assistance Program (GAP)		0.0121		
LDAC		**$ 0.0589**		**per therm**
Residential Heating Rates - R-3, R-4, R-6, R-7				
Energy Efficiency Charge	$ 0.0831			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$ 0.0831		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0197			
Environmental Surcharge (ES)		0.0197		
Revenue Decoupling Adjustment Factor (RDAF)		(0.0562)		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0000		
Rate Case Expense Factor (RCEF)		0.0002		
Gas Assistance Program (GAP)		0.0121		
LDAC		**$ 0.0589**		**per therm**
Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55				
Energy Efficiency Charge	$0.0441			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$ 0.0441	$ 0.0441	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0197			
Environmental Surcharge (ES)		0.0197	0.0197	
Revenue Decoupling Adjustment Factor (RDAF)		(0.0206)	(0.0206)	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0002	0.0002	
Gas Assistance Program (GAP)		0.0121	0.0121	
LDAC		**$ 0.0555**	**$ 0.0555**	**per therm**
Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56				
Energy Efficiency Charge	$0.0441			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0441	$0.0441	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0197			
Environmental Surcharge (ES)		0.0197	0.0197	
Revenue Decoupling Adjustment Factor (RDAF)		(0.0206)	(0.0206)	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0002	0.0002	
Gas Assistance Program (GAP)		0.0121	0.0121	
LDAC		**$ 0.0555**	**$ 0.0555**	**per therm**
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57,G-58				
Energy Efficiency Charge	$ 0.0441			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0441	$0.0441	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0197			
Environmental Surcharge (ES)		0.0197	0.0197	
Revenue Decoupling Adjustment Factor (RDAF)		(0.0206)	(0.0206)	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0002	0.0002	
Gas Assistance Program (GAP)		0.0121	0.0121	
LDAC		**$ 0.0555**	**$ 0.0555**	**per therm**

37 Residential Energy Efficiency Loan Program

Availability

Subject to the Terms and Conditions of the Tariff of which it is a part, this program shall allow Customers installing energy-efficiency measures under an energy efficiency program offered by the Company and approved by the Commission ("Participating Customers") to borrow all or a portion of the Customer's share of the installed cost of the energy-efficiency measures ("Customer Loan Amount") from the Company and to repay the Customer Loan Amount through an additional charge on their monthly retail delivery service bill issued by the Company. It is available to Participating Customers who meet the following qualifications:

A. The Participating Customer must own the property where the energy-efficiency measures are installed; and
B. A Participating Customer must have an active Delivery Service account with the Company for the property where the energy-efficiency measures are installed and receive Delivery Service under R-1, R-3, R-4, R-5, R-6, R-7 ; and
C. The Participating Customer must not have received a disconnect notice from the Company during the twelve months preceding the Participating Customer's request for a loan under this program; and
D. The Customer Loan Amount has no minimum and must be less than or equal to $4,000 per customer per year, and must not exceed the Participating Customer's share of the installed cost of the energy efficiency measures installed under the Company's approved energy-efficiency program; and
E. The Participating Customer must meet the qualifications of the applicable energy-efficiency program through which the energy-efficiency measures are being installed.

At its sole discretion, the Company shall determine eligibility for service under this program subject to the availability of program funds.

Any Participating Customer receiving a loan under this program must remain a Delivery Service customer of the Company at the property where the energy-efficiency measures are installed until the loan has been repaid in full. In the event the Participating Customer ceases to be a Delivery Service Customer of the Company at the property where the energy-efficiency measures are installed, any remaining charges under this program shall immediately become due and payable.

Customer Loan Agreement

Participating Customers shall be required to execute a separate Residential Customer Loan Agreement which will specify the fixed monthly charge and other applicable terms. A Participating Customer can choose to pay the remaining balance owed to the Company at any time. A late payment charge as described in the Terms and Conditions for Delivery Service section of the Company's Tariff is applicable to the monthly charges rendered under this program. Participating Customers are not subject to disconnection of natural gas service for nonpayment of the charges under this program.

The Customer Loan Amount shall be paid to the Company by the Participating Customer through a fixed monthly charge applied over a term of months as established in the Customer Loan Agreement. Participating Customers may specify the repayment term of the Customer Loan Amount subject to the maximum repayment term limit of 48 months.

38 Non-Residential Energy Efficiency Loan Program

Availability

Subject to the Terms and Conditions of the Tariff of which it is a part, this program shall allow Customers installing energy-efficiency measures under an energy efficiency program offered by the Company and approved by the Commission ("Participating Customers") to borrow all or a portion of the Customer's share of the installed cost of the energy-efficiency measures ("Customer Loan Amount") from the Company and to repay the Customer Loan Amount through an additional charge on their monthly retail delivery service bill issued by the Company. It is available to Participating Customers who meet the following qualifications:

A. The Participating Customer must own the property where the energy-efficiency measures are installed; and
B. A Participating Customer must have an active Delivery Service account with the Company for the property where the energy-efficiency measures are installed and receive Delivery Service under G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57, or G-58; and
C. The Participating Customer must not have received a disconnect notice from the Company during the twelve months preceding the Participating Customer's request for service under this program; and
D. The Customer Loan Amount has no minimum and must be less than or equal to $50,000 for each project, and must not exceed the Participating Customer's share of the installed cost of the energy efficiency measures installed under the Company's approved energy-efficiency program; and
E. A Participating Customer is limited to $150,000 per year in loan funds with no limit on the number of projects at the sole discretion of the Company based on program demand. If at any point there are no loan fund recipients or there have been no loan fund recipients in a given year, the Company may petition the Commission to allow a particular customer to receive more than $150,000 in loan funds in a given year; and
F. The Participating Customer must meet the qualifications of the applicable energy-efficiency program through which the energy-efficiency measures are being installed.

At its sole discretion, the Company shall determine eligibility for service under this program subject to the availability of program funds.

Any Participating Customer receiving a loan under this program must remain a Delivery Service customer of the Company at the property where the energy-efficiency measures are installed until the loan has been repaid in full. In the event the Participating Customer ceases to be a Delivery Service Customer of the Company at the property where the energy-efficiency measures are installed, any remaining charges under this program shall immediately become due and payable.

Customer Loan Agreement

Participating Customers shall be required to execute a separate Non-Residential Customer Loan Agreement which will specify the fixed monthly charge and other terms of the loan. A Participating Customer can choose to pay the remaining balance owed to the Company at any time. A late payment charge as described in the Terms and Conditions for Delivery Service section of the Company's Tariff is applicable to the monthly charges rendered under this program. Participating Customers are not subject to disconnection of natural gas service for nonpayment of the charges under this program.

The Customer Loan Amount shall be paid to the Company by the Participating Customer through a fixed monthly charge applied over a term of months as established in the Customer Loan Agreement. Participating Customers may specify the repayment term of the Customer Loan Amount subject to the maximum repayment term limit of 60 months.

III. DELIVERY TERMS AND CONDITIONS

1 RATES AND CHARGES

1.1 The Company shall apply this tariff on a non-discriminatory and non-preferential basis to all Customers who obtain service from the Company, except as this tariff is explicitly modified by order of the NHPUC. The provisions of Part III Section 20 of this tariff will specifically apply to all entities designated by the Customer as set forth in Section 20.5 to supply Gas to a Designated Receipt Point for the Customer's account.

1.2 The Company reserves the right to impose reasonable fees and charges pursuant to the various provisions of this tariff.

1.3 In the event that the Company incurs minimum bill, inventory, transition, take or pay, imbalance, or any other charges associated with the provision of Delivery Service to Customers, the Company may impose an additional charge on the Suppliers serving said Customers as approved by the NHPUC.

2 DEFINITIONS

Adjusted Target Volume ("ATV)	The volume of Gas determined by the Company using a Consumption Algorithm and required to be nominated and delivered each Gas Day by the Supplier on behalf of Customers taking non-daily metered Delivery Service.
Aggregation Pool	One or more Customer accounts whose Gas Usage is served by the same Supplier and aggregated pursuant to Section 20.6 of this tariff for operational purposes, including but not limited to nominating, scheduling, and balancing Gas deliveries to Designated Receipt Point(s) within the associated Gas Service Area.
Annual Reassignment Date	Five (5) Business Days prior to November 1 of each year when the Company reassigns Capacity to Suppliers pursuant to Section 11.6 of this tariff.
Assignment Date	Five (5) Business Days prior to the first Gas Day of each month when the Company assigns Capacity to Suppliers pursuant to Section 11.4 of this tariff.
Authorization Number	A number unique to the Customer generated by the Company and printed on the Customer's bill that the Customer must furnish to the Supplier to enable the Supplier to obtain the Customer's Gas Usage information pursuant to Section 20.4, and to initiate or terminate Supplier Service as set forth in Section 20.5 of this tariff.
Btu	One British thermal unit; i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit.
Business Day	Monday through Friday excluding holidays recognized by the Company. Where relevant, a Business Day shall consist of the hours during which the Company is open for business with the public. ***If any performance date referenced in this Tariff is not a Business Day, such performance shall be the next succeeding Business Day***.
Capacity	Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity as defined in this tariff.

Capacity Allocators	The estimated proportions of the Customer's Total Capacity Quantity that comprise Pipeline Capacity, Storage Withdrawal Capacity and Peaking Capacity.
Capacity Mitigation Service	The service available to Suppliers in accordance with Section 11.10.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Commodity	See Gas.
Company	Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Company Gas Allowance	The difference between the sum of all amounts of Gas received into the Company's distribution system (including Gas produced by the Company) and the sum of all amounts of Gas delivered from the Company's distribution system divided by said amount of Gas received. Such difference shall include but not be limited to Gas consumed by the Company for its own purposes, line losses, and Gas vented and lost as a result of force majeure, excluding Gas otherwise accounted for.
Company-Managed Supplies	Capacity and Supply contracts held and managed by the Company and made available to the Supplier pursuant to Section 11.9 of this tariff including Supply-sharing contracts and load-management contracts.
Consumption Algorithm	A mathematical formula used to estimate a Customer's daily consumption.
Critical Day	In accordance with Section 16 of this tariff, a day declared at any time by the Company in its reasonable discretion when unusual operating conditions may jeopardize operation of the Company's distribution system.
Customer	The recipient of Delivery Service whose Gas Usage is recorded by a meter or group of meters at a specific location and who is a customer of record of the Company.
Daily Baseload	The Customer's average usage per Gas Day that is assumed to be unrelated to weather.
Daily Index	The mid-point of the range of prices as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)". In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of Gas as the basis for this calculation until such time that the NHPUC approves a suitable replacement.
Dekatherm	Ten Therms.
Delivery Point	The interconnection between the Company's facilities and the Customer's facilities.
Delivery Service	The distribution of Gas by the Company on any Gas Day from the Designated Receipt Point to the Customer's Delivery Point and related Customer services.
Design Peak Season	The forecasted Peak Season during which the Company's system experiences the highest aggregate Gas Usage.
Designated Receipt Point	For each Customer, the Company designated interconnection between a Transporting Pipeline and the Company's distribution facilities at which

point, or such other point as the Company may designate from time to time for operational purposes, the Supplier will make deliveries of Gas for the Customer's account.

Designated Representative	The designated representative of the Customer, who shall be authorized to act for, and conclusively bind, the Customer regarding Delivery Service in accordance with the provisions of Section 21 of this tariff.
Gas	Natural Gas that is received by the Company from a Transporting Pipeline at the Designated Receipt Point and delivered by the Company to the Delivery Point for the Customer's account. In addition, the term shall include amounts of vaporized liquefied natural Gas and/or propane-air vapor that are introduced by the Company into its system and made available to the Customer as the equivalent of natural Gas that the Customer is otherwise entitled to have delivered by the Company.
Gas Day	A period of twenty-four (24) consecutive hours beginning at 10:00 a.m., E.T., and ending at 10:00 a.m., E.T., the next calendar day, or other such hours used by the Transporting Pipeline.
Gas Service Area	An area within the Company's distribution system as defined in Section 4 of this tariff, for the purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools.
Gas Usage	The actual quantity of Gas used by the Customer as measured by the Company's metering equipment at the Delivery Point.
Heating Degree Day	A measure used to estimate weather-sensitive Gas consumption calculated by subtracting the average temperature for each day from the number 65. Each degree day that represents a degree below 65 is considered a Heating Degree Day.
Heating Factor	The Customer's estimated weather-sensitive Gas consumption per Heating Degree Day.
MMBtu	One million Btus.
Maximum Daily Peaking	The portion of a Customer's Total Capacity Quantity identified
Quantity ("MDPQ")	and allocated as Peaking Capacity, such that the maximum daily amount of Gas that can be withdrawn from a Supplier's Peaking Service Account pursuant to Section 14 of this tariff shall be equal to the sum of the MDPQs for all Customers in that Supplier's Aggregation Pool.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Index numbers for all Gas Days in a Month.
NHPUC	The New Hampshire Public Utilities Commission.
Nomination	The notice given by the Supplier to the Company that specifies, in accordance with the Standard Nomination Form attached as Attachment A, an intent to deliver a quantity of Gas to the Designated Receipt Point(s) on behalf of one or more Customers, including the volume to be received, the Designated Receipt Point(s), the Transporting Pipeline, the delivering contract(s), the shipper, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months of May to October, inclusive.

Operational Flow Order ("OFO")	The Company's instructions to the Supplier to take such action as conditions require including, but not limited to, diverting Gas to or from the Company's distribution system pursuant to Section 16 of this tariff.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage.
Peak Season	The consecutive months of November to April, inclusive.
Peaking Capacity	Capacity in addition to upstream pipeline and underground storage Capacity normally used by the Company to meet daily requirements during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Service	A Company-managed resource consisting of Peaking Capacity and Peaking Supply.
Peaking Service Account	An account whose balance indicates the total volumes of Peaking Service resources available to a Supplier, where the maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to this tariff.
Peaking Service Rule Curve	A system of operational parameters associated with the use of the Company's Peaking Capacity including, but not limited to, indicators of the necessary levels of Peaking Supply that must be maintained in Suppliers' Peaking Service Accounts in order for the Company to meet system demands under Design Peak Season conditions. The Company will communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Peaking Service Rule Curve as identified in Section 14 of this tariff.
Peaking Supply	The aggregate amount of Supply in excess of upstream pipeline and underground storage Supply required to meet the Company's forecasted Supply needs during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Supply Allocator	An allocation factor that represents the proportion of a Customer's estimated Gas Usage during the Design Peak Season that is generally served with Peaking Service supplies.
Pipeline Capacity	Transportation capacity on interstate pipeline systems normally used for deliveries of Gas to the Company's city gates, exclusive of Storage Withdrawal Capacity.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the method allocation of discrepancies in confirmed Nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier Service Agreement.
Rate Schedule	The schedule of rates included in this tariff.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.
Sales Service	Commodity service provided on a firm basis to a Customer who is not receiving Supplier Service, in accordance with the provisions set forth in this tariff. The provision of Sales Service shall be the responsibility of the Company and shall be provided to the Customer by the Company or its designated Supplier pursuant to law or regulation.

Seasonal Storage Capacity	Contracts for Capacity in off-system storage facilities used to accumulate and maintain Gas inventories for re-delivery to the Company's city gates normally during the Peak Season.
Storage Withdrawal Capacity	Capacity for the withdrawal of Gas inventories maintained in off-system storage facilities, as well as the Pipeline Capacity used to deliver such Gas to the Company's city gates.
Supplier	Any entity that has met the Company's requirements set forth in Section 20 of this tariff and that has been designated by a Customer to supply Gas to a Designated Receipt Point for the Customer's account; provided, however, that a Customer may act as its own Supplier in accordance with Section 5.2 of this tariff.
Supplier Service	The sale of Gas to a Customer by a Supplier.
Supplier Service Agreement	An agreement, substantially in the form set forth in Attachment A, which must be executed by the Company and a Supplier in order for the Supplier to serve Customers on the Company's system.
Supply	See Gas.
Therm	An amount of Gas having a thermal content of 100,000 Btus.
Total Capacity Quantity	The total amount of Capacity assignable to a Supplier on behalf
("TCQ")	of a Customer.
Transporting Pipeline	The interstate pipeline company that transports and delivers Gas to the Designated Receipt Point.

3 CHARACTER OF SERVICE

3.1 All rates within Part II Rate Schedule are predicated upon service to a Customer at a single Delivery Point and metering installation, except as otherwise specifically provided by a given rate. Where service is supplied to a Customer at more than one Delivery Point or metering installation, each single Delivery Point or metering installation shall be considered to be a separate Customer for purposes of applying the Rate Schedule, except when a Customer is served through multiple points of delivery or metering installations for the Company's own convenience.

3.2 The Company may refuse to supply service to loads of unusual characteristics which, in its sole reasonable judgment, might adversely affect the quality of service supplied to other Customers, the public safety or the safety of the Company's personnel. In lieu of such refusal, the Company may require a Customer to install any necessary regulating and protective equipment in accordance with the requirements and specifications of the Company.

4 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS

4.1 There shall be 1 Gas Service Area defined for purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools pursuant to this tariff. Each such Gas Service Area shall be defined to include the municipalities listed within each such Gas Service Area, as follows:

(1) Area 1: Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty.
The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin,

Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelham, Pembroke, Sanbornton, Tilton, Windham, and part of Canterbury.

4.2 For each Aggregation Pool as set forth by Section 20.6, the Company will designate at least one specific interconnection between a Transporting Pipeline and the Company's distribution facilities, at which point, or such other point as the Company may designate from time to time, the Supplier will make deliveries for the Aggregation Pool. The interconnections that the Company may assign as the Customer's Designated Receipt Point for the Aggregation Pool are as follows:

(1) *Name Transporting Pipeline: Tennessee Gas Pipeline*
Names of City Gates/Meter Numbers:

Nashua/Milford	#020132
Manchester	#020133
Hooksett	#020254
Concord/Laconia	#020426
Suncook	#020451
Londonderry	#020632

(2) *Name Transporting Pipeline: Portland Natural Gas Transmission System*
Names of City Gates/Meter Number

Berlin	#020260

5 CUSTOMER REQUEST FOR SERVICE FROM COMPANY

5.1 Application for Delivery Service, Sales Service, or any other service offered by the Company to a Customer will be received by any duly authorized representative or agent of the Company.

5.2 Before any service from the Company may commence, the Customer must request such service. A Customer applying for Delivery Service only must also arrange for Supplier Service with a Supplier pursuant to Section 20. A Customer may act as its own Supplier provided it meets all of the Supplier requirements delineated in Section 20.

6 QUALITY AND CONDITION OF GAS

6.1 Gas delivered to the Company by or for the Customer shall conform, in all respects, to the Gas quality standards of the Transporting Pipeline. All Gas tendered by a Supplier at a Designated Receipt Point shall be of merchantable quality and shall be interchangeable with Gas purchased by the Company from its Suppliers. The Company reserves the right to refuse non-conforming Gas.

6.2 In no event shall the Company be obligated to accept and deliver any Gas that does not meet the quality standards of the Transporting Pipeline.

6.3 The Company reserves the right to commingle Gas tendered by a Supplier at a Designated Receipt Point with other Gas, including liquefied natural Gas and propane-air vapor.

6.4 Gas tendered by a Supplier at a Designated Receipt Point will be at a pressure sufficient to enter the Company's distribution system without requiring the Company to adjust its normal operating pressures to receive the Gas. The Company has no obligation to receive Gas at a pressure that exceeds the maximum allowable operating pressure of the Company's distribution system at the Designated Receipt Point.

7 POSSESSION OF GAS

7.1 Gas shall be deemed to be in the control and possession of the Company after such Gas is delivered to the Designated Receipt Point and until the Gas is delivered to the Customer at the Delivery Point. The Company shall not be responsible for the Gas when the Gas is not in the Company's control and possession.

7.2 The Company shall not be liable to the Supplier or the Customer for any loss arising from or out of Delivery Service, including loss of Gas in the possession of the Company or for any other cause, except for the negligence of the Company's own employees or agents.

8 COMPANY GAS ALLOWANCE

8.1 The amount of Gas tendered by the Supplier to the Designated Receipt Point will be reduced, upon delivery to the Customer's Delivery Point, by the Company Gas Allowance. The Company Gas Allowance shall be in effect from November 1 through October 31. Such adjustment shall be recalculated prior to the Company's Peak Season cost of Gas filing with the NHPUC.

9 DAILY METERED DELIVERY SERVICE

9.1 Applicability

Section 9 of this tariff shall be applicable in the following conditions:

9.1.1 All Customers whose service may be interrupted at any time during the year shall be required to take daily metered Delivery Service.

9.1.2 Any Customer, regardless of annual Gas Usage, may elect daily metered Delivery Service.

9.1.3 Customers under Rate Schedules G-43, G-46, G-53, G-54, G-57, and G-58 wishing to take Delivery Service are required to take Daily Metered Delivery Service. In addition, the Company may require a Customer to take daily metered Delivery Service if the Company determines that the daily Gas Usage characteristics of the Customer cannot be accurately modeled using the Company's Consumption Algorithm or if the volumes reasonably anticipated by the Company to be used by the Customer are of a size that may materially affect the integrity of the Company's distribution system.

9.2 Delivery Service Provided

This service provides delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day. For Customers taking Delivery Service under Rate Schedules ***G-43, G-46, G-53, G-54, G-57, and G-58*** this service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point.

9.3 Nominations and Scheduling of Service

9.3.1 The Supplier is responsible for nominating and delivering to the Designated Receipt Point(s) every Gas Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool plus the Company Gas Allowance in accordance with Section 8 of this tariff.

9.3.2 Nominations shall be communicated to the Company by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means.

9.3.3 Nominations for the first Gas Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month Nominations of the Transporting Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of Nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.4 The Supplier may make daily Nominations including, but not limited to, changes to existing Nominations, within a given Month no later than two (2) hours prior to the deadline for daily Nominations of the Transporting Pipeline for the Gas Day on which the Nomination is to be effective, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.5 The Supplier may make intra-Gas Day Nominations, including but not limited to changes to existing Nominations, within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis.

9.3.7 Nominations may be rejected, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Delivery Service in effect from time to time.

9.4 Determination of Receipts

9.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

9.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

9.5 Metering and Determination of Deliveries

9.5.1 The Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. Telemetering equipment shall remain the property of the Company at all times. The Company shall require each Customer to install and maintain, at the Customer's expense, reliable telephone lines and electrical connections that meet the Company's operating requirements. The Company may require the Customer to furnish a dedicated telephone line. If the Customer fails to maintain such telephone lines and electrical connections for fourteen (14) consecutive days after notification by the Company, the Company may discontinue service to the Customer.

9.5.2 Should a Customer or a Supplier request that additional telemetering equipment or a communication device be attached to the existing telemetering equipment in addition to that provided pursuant to Section 9.5.1, the Company shall install, test, and maintain the requested telemetering equipment or communication device; provided that such telemetering equipment or communication device does not interfere with the operation of the equipment required for the Company's purposes and otherwise meet the Company's requirements. The Customer or Supplier shall provide such telemetering equipment or communication device, unless the Company elects to do so. The Customer or Supplier shall bear the cost of providing and installing the telemetering equipment, communication device, or any other related equipment, and shall have electronic access to the Customer's Gas Usage information. Upon installation, the telemetering equipment or communication device shall become the property of the Company and will be maintained by the Company. The Company shall bill the Customer or Supplier after installation.

9.5.3 The Company shall complete installation of telemetering equipment and communication devices, if reasonably possible, within sixty (60) days of receiving a written request from the Customer or Supplier provided that the Customer completes the installation of any required telephone or electrical connections within ten (10) days of such request.

9.5.4 The Company may, at its sole discretion, bill the Customer on a calendar month or cycle month basis.

9.6 Balancing

9.6.1 The Supplier must maintain a balance between daily receipts and daily Gas Usage within the following tolerances:

Off-Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 15% of said receipts. The Supplier shall be charged 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 10% of said receipts. The Supplier shall be charged 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 102% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool exceeds 20% of said receipts [(Receipts - Usage) > (20% x Receipts)].

Critical Day That Will Be Aggravated by Over-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 120% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 5 times the Daily Index to the extent that the difference between the Supplier's actual receipts on the Transporting Pipeline to each Gas Service Area and the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 2% of said receipts [(Receipts - Usage > (2% x Receipts)].

Point Specific Balancing: In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

9.6.2 If the Supplier has an accumulated imbalance within a Month, the Supplier may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

9.6.3 In addition to the charges set forth in Section 9.6.1, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

9.6.4 If, as a result of the Company interrupting or curtailing service pursuant to Section 17 of this tariff, the Supplier incurs a daily imbalance penalty due to over delivery, the Company will waive such penalty for the First Day of the interruption or curtailment period. If the Company has issued notice of an interruption or curtailment in service and the Supplier is unable to change its Nomination, or if the Supplier's Gas has been delivered to the Designated Receipt Point, then the Company will credit such Gas against the Supplier's imbalance.

9.6.5 The Supplier will maintain a balance between receipts at the Designated Receipt Point(s) and the aggregated Gas Usage of Customers in each Aggregation Pool. If the Transporting Pipeline posts notice on its electronic bulletin board that its customers will be required to adhere to a maximum hourly flow rate, the Supplier will be deemed to have notice that maximum hourly flows will be in effect on the Company's distribution facilities as of the same time and for the same period as maximum hourly flows are in effect on the Transporting Pipeline. The Supplier's maximum hourly flow will be established based on an allocation of even hourly flows of daily receipts of Gas scheduled in the relevant period in accordance with the applicable transportation tariff of the Transporting Pipeline. All Gas Usage in excess of the Supplier's maximum hourly flow rate shall be subject to an additional charge of 5 times the Daily Index for each Dekatherm in excess of the Supplier's maximum hourly flow. The Company will notify the Supplier of the Supplier's maximum hourly flow.

9.6.6 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the aggregated Gas Usage of Customers in the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, and storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

9.7 Cash Out

For each Aggregation Pool, the Supplier must maintain total Monthly receipts within a reasonable tolerance of total Monthly Gas Usage. Any differences between total Monthly receipts for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a percentage of total Monthly receipts, will be cashed out according to the following schedule:

Imbalance Tier	Over-deliveries	Under-deliveries
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month
> 5% ≤ 10%	0.85 times the above stated rate.	1.15 times the above stated rate.
> 10% ≤ 15%	0.60 times the above stated rate.	1.4 times the above stated rate.
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% under-delivery on a Transporting Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven (7) consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven (7) consecutive Daily Indices.

10 NON-DAILY METERED DELIVERY SERVICE

10.1 Applicability

Section 10 of this tariff applies to Customers taking Delivery Service under Rate Schedules G-41, G-42, G-51, G-52 and their Suppliers.

10.2 Delivery Service Provided

This service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day for Customers, without the requirement of recording Gas Usage at the Delivery Point on a daily basis. Daily Nominations are calculated by the Company on the basis of a Consumption Algorithm and the Supplier is obligated to deliver to the Designated Receipt Point(s) such quantities.

10.3 Nominations and Scheduling of Service

10.3.1 The Supplier is obligated to nominate and deliver the Adjusted Target Volume ("ATV"), as determined in Section 10.3.2, to the Designated Receipt Points on every Gas Day for each Aggregation Pool.

10.3.2 The Company shall determine the ATV for each Aggregation Pool of Customers taking non-daily metered Delivery Service for each Gas Day using a Consumption Algorithm. The ATV shall include the Company Gas Allowance. On each Business Day, the Company will communicate, electronically, by facsimile, or by other agreeable alternative means, the forecasted ATV to the Supplier for at least the subsequent four (4) Gas Days. The ATV in effect for any Gas Day shall be the most recent ATV for that Gas Day communicated to the Supplier by the Company. The ATV for a given Gas Day shall not be effective unless it has been communicated to the Supplier at least two (2) hours prior to the Company's Supplier Nomination deadline for that Gas Day, which shall be at least two (2) hours prior to the deadline for nominations on the Transporting Pipeline, or such lesser period as determined by the Company.

10.3.3 Nominations will be communicated to the Company electronically, by facsimile, or other agreeable alternative means.

10.3.4 Nominations for the first Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month nominations of the Delivering Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.5 The Supplier shall provide an intra-Month nomination no later than two (2) hours prior to the deadline of the Delivering Pipeline for the next Gas Day, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis. The Company will not confirm any volume nominated by the Supplier in excess of the ATV.

10.3.7 In the event that the Supplier is unable to deliver a confirmed ATV Nomination, the Supplier may make intra-Gas Day Nominations relating to changes to existing Nominations within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company; provided, however, that the

10.3.8 Nomination must be in conformance with the requirements of and must be permitted by the Transporting Pipeline. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized by the Company for its own operations. The Company shall not adjust the ATV applied for the Gas Day.

10.3.9 Nominations may be rejected if they do not satisfy the conditions for Delivery Service in effect from time to time.

10.3.10 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an Operational Flow Order ("OFO") declared by the Company pursuant to Section 16 will be subject to the Critical Day provisions of Section 10.6.1 of this tariff, and the delivered quantity specified in the OFO will replace the ATV.

10.4 Determination of Receipts

10.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

10.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

10.5 Metering and the Determination of Deliveries

The Company shall record the Customer's Gas Usage at the Delivery Point by making actual meter reads on a monthly [or bi-monthly] basis. In the event that the Customer's Gas Usage is metered on a bi-monthly basis, the Company shall make available to the Supplier estimates of the Customer's Gas Usage for each of the two billing months.

10.6 Balancing

10.6.1 Any difference between the Supplier's ATV for an Aggregation Pool and the receipts on the Transporting Pipeline to the appropriate Designated Receipt Point(s) will be cashed out by the Company according to the following:

Off-Peak Season: For receipts less than the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Peak Season: For receipts less than the ATV but greater than or equal to 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts less than 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the first 5% difference, and the Supplier shall be charged two (2) times the Daily Index for the remaining difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day(s) The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

<u>Critical Day That Will Be Aggravated by Under-delivery</u>.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged five (5) times the Daily Index for the difference between the ATV and actual receipts.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged the following amounts for all receipts in excess of the ATV:

(a) up to 25% in excess of the ATV, the Supplier shall be charged the Daily Index for the difference.

(b) for receipts in excess of 25% above the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day That Will Be Aggravated By Over-delivery.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.4 times the Daily Index for receipts greater than the ATV.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged the following amounts--for receipts less than the ATV but greater than or equal to 75% of the ATV, the Supplier shall be charged the Daily Index for the first 25% difference, and the Supplier shall be charged 1.1 times the Daily Index for the remaining difference.

10.6.2 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

10.6.3 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

10.6.4 In addition to the charges set forth in Sections 10.6.1 and 10.6.2, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

10.7 Cash Out

10.7.1 The Company shall use a daily cash out calculation to account for imbalances due to differences in forecast versus actual Heating Degree Days. Using a Consumption Algorithm, the Company will recalculate the ATV for each Aggregation Pool for each Gas Day of the Month, substituting actual Heating Degree Days for forecast Heating Degree Days. Daily recalculations shall be compared to the Aggregation Pool's daily ATV, and the difference shall be cashed out at 100% of the Daily Index.

10.7.2 During the billing months of both June and December, the Company shall use a six-month cash-out calculation to account for differences in forecast usage versus billed Gas Usage. The Company may cash-out differences in forecast usage versus billed usage at intervals that are less than six months as provided by the Supplier Service Agreement.

(1) In the billing month of June, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of November 1 through April 30 to the sum of billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index weighted by actual Heating Degree Days over the same period. The Winter period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending April 30.

(2) In the billing month of December, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of May 1 through October 31 to the sum of the billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index over the same period. The Off-Peak period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending October 31.

10.7.3 The Company shall allow Suppliers to trade seasonal differences. Prior to the seasonal cash-out, the Company shall make available a list of Suppliers. Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company. All trades must be communicated to the Company within three (3) Business Days following receipt of the list.

10.7.4 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the ATVs of the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the Supplier's estimated maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to

10.7.5 satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

11 CAPACITY ASSIGNMENT

11.1 Applicability

Section 11 of this tariff applies to all Suppliers that have enrolled one or more Customers into one or more Aggregation Pools and shall include Customers acting as their own Supplier. The Company shall assign and the Supplier shall accept each Customer's pro-rata share of Capacity, if any, as established in accordance with this Section.

11.2 Identification of Capacity for Assignment

11.2.1 On or before September 15 of each year, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Capacity to be made available for assignment to Suppliers on each of twelve Assignment Dates beginning in October.

11.2.2 The Company shall identify, by Gas Service Area, the specific contracts and resources for assignment to Suppliers based on the Company's Capacity and resource plans. Such identified contracts and resources shall be used to determine the pro-rata shares of Capacity assignable to a Supplier on behalf of the Customers enrolled in its Aggregation Pool.

11.2.3 Capacity assigned by the Company may include Company-Managed Supplies that effectuate, at maximum tariff rates, the assignment of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)] and other contracts that are not assignable to third-parties due to governing tariffs.

11.3 Determination of Pro-Rata Shares of Capacity

11.3.2 The Company shall establish a Total Capacity Quantity ("TCQ") for each Customer taking Delivery Service. The TCQ represents the total amount of Capacity assignable to a Supplier on behalf of a Customer.

11.3.3 For a Customer receiving Sales Service on or after March 14, 2000, the TCQ shall be the Customer's estimated Gas Usage on the Peak Day as determined by the Company each October prior to the Customer's enrollment into Supplier Service. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during the Reference Period, or the best estimates available to the Company should actual Gas Usage information be partially or wholly unavailable.

11.3.4 For a Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had an executed contract for firm transportation service (i.e., the equivalent of Delivery Service) on file with the Company on or before March 14, 2000, the TCQ shall be zero.

11.3.5 A Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had a written request on file with the Company on or before March 14, 2000 may elect for its Supplier to accept assignment of its pro-rata share of Capacity as determined by the Company in accordance with Section 11.2 and, subject to availability, as determined by the Company in its sole reasonable discretion. In order to make such election, the Customer must have submitted to the Company, on or before ten (10) days prior to the first Assignment Date prior to the original effective date of this tariff, a completed application for Capacity that is signed by both the Customer and Supplier. All assignments of Capacity made on behalf of such electing Customer shall be executed in accordance with Sections 11 and 14 of this tariff as if the Customer had been receiving Sales Service on or after March 14, 2000

11.3.5 For a new Customer taking Supplier Service as its initial service after March 14, 2000, the TCQ shall be zero except in cases where the Customer is a new Customer of record at a meter location where a former Customer of record received firm service from the Company any time during the preceding twenty-four (24) months, in which case the TCQ established by the Company for the former Customer shall become the TCQ for the new Customer. The Company may reduce said TCQ value for the new Customer, if, in its sole reasonable discretion, the Company determines that the old Customer's TCQ exceeds the new Customer's estimated future consumption on the Peak Day. In the event that Sales Service is provided at a new meter location for Gas Usage associated with new construction, the TCQ shall be zero, provided that the Customer initiates Supplier Service upon the completion of said new construction in accordance with Section 20.5 of this tariff

11.3.6 Once the Company establishes a TCQ for a Customer pursuant to this Section 11.3, it shall remain in effect for the purpose of determining the Customer's pro-rata shares of Capacity until such time that the Customer returns to Sales Service. The Company shall establish a new TCQ value for the Customer pursuant to Section 11.3.2 if the Customer again elects to take Supplier Service after returning to Sales Service, unless otherwise established herein..

11.3.7 The Company shall determine the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assignable to a Supplier on behalf of a Customer as the product of the Customer's TCQ times the applicable Capacity Allocators. The Capacity Allocators for each class of Customers billed under the Company's Rate Schedule shall be set forth annually in Attachment C to this tariff.

11.3.8 The Company shall determine the pro-rata share of Seasonal Storage Capacity assignable to a Supplier on behalf of a Customer consistent with the tariffs governing the associated Storage Withdrawal Capacity.

11.3.9 The Company shall determine the pro-rata shares of Peaking Supply assignable to a Supplier in accordance with Section 14 of this tariff.

11.4 Capacity Assignments

11.4.1 On each Assignment Date, the Company will assign to the Supplier the pro-rata shares of Capacity on behalf of each Customer as determined by the Company in accordance with Sections 11.2, 11.3 and 11.7.

11.4.2 The total amount of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assigned to the Supplier on behalf of the Customers in an Aggregation Pool shall be at least equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of Five (5) Business Days prior to the Assignment Date.

11.4.3 Storage Withdrawal Capacity shall be subject to Operational Flow Orders that are issued by the Company pursuant to Section 16 of this tariff, in the event that the Company requires the Supplier to deliver or to store quantities of Gas for the purposes of managing system imbalances and maintaining Delivery Service. Whenever the Company assigns incremental Storage Withdrawal Capacity to the Supplier, the Company shall also assign to that Supplier additional Seasonal Storage Capacity pursuant to Section 11.8.

11.4.4 The Peaking Capacity assigned to the Supplier shall establish the Maximum Daily Peaking Quantity ("MDPQ") for the Aggregation Pool in the Supplier's Service Agreement. In the event that the Company increases a Supplier's MDPQ, the Company shall also assign to that Supplier additional Peaking Supply pursuant to Section 14.

11.4.5 The Company shall execute Capacity assignments in increments of 200 MMBtus. The Supplier shall accept an initial increment of Capacity on the first Assignment Date when the sum of the pro-rata shares of Capacity assigned to the Supplier pursuant to Section 11.4.1 exceeds 150 MMBtus. The Supplier shall accept additional increments of Capacity on the following Assignment Dates commensurate with any cumulative increase in the sum of pro-rata shares of Capacity assigned to the Supplier, as rounded to the nearest 200 MMBtus. Each increment of Capacity accepted by the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative increase of the pro-rata shares of assigned Capacity as established in accordance with Section 11.4.1. Section 11.4.2 shall not apply to a Customer that is acting as its own Supplier.

11.4.6 If a Customer is acting as its own Supplier, the Company shall assign Capacity to the Customer in an amount equal to the Customer's TCQ, as established pursuant to Section 11.3.

11.5 Release of Contracts

11.5.1 With the exception of Company-Managed Supplies and Peaking Capacity, Capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or lesser rate paid by the Company and including all surcharges, through pre-arranged Capacity releases, pursuant to applicable laws and regulations and the terms of the governing tariffs.

11.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released for a term beginning on the first Gas Day of the Month following the Assignment Date through the expiration date of the respective capacity contract being assigned. and ending on October 31. For example, contracts assigned to a Supplier on April 25 of a given year shall be released for a term beginning on May 1 of that year and ending on October 31 of that year.

11.5.3 The Company reserves the right to adjust releases of Storage Withdrawal Capacity in the event that fifty percent (50%) or more of the total Storage Withdrawal Capacity serving a Gas Service Area has been assigned to Suppliers. Such adjustments may include, but are not limited to, the reassignment of certain Storage Withdrawal Capacity as Company-Managed Supplies in order for the Company to maintain operational control over Capacity resources associated with system balancing, and/or the retention of specific Capacity resources associated with system balancing and the implementation of a balancing charge to offset the associated costs.

11.6 Annual Reassignment of Capacity

11.6.1 On each Annual Reassignment Date, the Company shall adjust the Capacity assignments previously made to a Supplier to conform with the Company's resource and requirements plans. Such previously assigned Capacity shall be replaced by the assignment to the Supplier of the pro-rata shares of the same or similarly situated Capacity on behalf of the

Customers enrolled in the Supplier's Aggregation Pools (as of the first Gas Day of the Month following the Annual Reassignment Date).

11.6.2 If the reassignment of Storage Withdrawal Capacity requires adjustments to the Seasonal Storage Capacity previously assigned to a Supplier, the Company shall reassign Seasonal Storage Capacity to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to inventories in place pursuant to Section 11.8 of this tariff.

11.6.3 If the reassignment of Peaking Capacity requires adjustments to the MDPQ for the Supplier's Aggregation Pool, the Company shall reassign Peaking Supply to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to supplies pursuant to Section 14 of this tariff.

11.7 Recall of Capacity

11.7.1 If the pro-rata shares of Capacity assignable to a Supplier decline because one or more of the Supplier's Customers has returned to Sales Service, the Company shall have the right, but not the obligation, to recall from the Supplier the pro-rata shares of Capacity previously assigned to the Supplier on behalf of such Customers. The decision on whether to exercise its Capacity-recall rights shall be made by the Company in its sole reasonable discretion. If the Company elects to recall Capacity from a Supplier pursuant to this Section, such recall shall be made on the Assignment Date following the effective date of the Customer's return to Sales Service. Notwithstanding the foregoing, in the following circumstances the Company shall be required to recall Capacity associated with Customers returning to Sales Service:

(a) The Supplier returning the Customers to Sales Service certifies that it is ceasing all business operations in New Hampshire;

(b) The Supplier returning the Customers to Sales Service certifies that it will no longer offer service to a particular market sector (e.g., small commercial and industrial Customers) and, therefore, once such Customers are returned to Sales Service, the Supplier is not eligible to re-enroll Customers of that type; or

(c) The Supplier demonstrates that it has provided Supplier Service to the Customer for a 12-month period, and for a period of no less than any 12-month increment, prior to the Customer's return to Sales Service.

11.7.2 If the Company elects to recall Storage Withdrawal Capacity from the Supplier pursuant to this Section, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company elects to reduce the MDPQ in the Supplier Service Agreement, the Company shall reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.3 In the event that a Customer in a Supplier's Aggregation Pool switches to another Supplier, the Company shall recall from the former Supplier said Customer's pro-rata shares of Capacity for reassignment to the new Supplier pursuant to Section 11.4. There shall be no change in the Customer's TCQ used to determine the Customer's pro-rata shares of Capacity for reassignment to the new Supplier. The recall of such Capacity from the Customer's former Supplier and the assignment of Capacity to the new Supplier shall be made on the Assignment Date following the effective date of the Customer's switch in Suppliers.

If the Company recalls Storage Withdrawal Capacity from the Customer's former Supplier, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company reduces the MDPQ in the Customer's former Supplier's Service Agreement, the Company shall also reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.4 The recall of Capacity by the Company shall entail the recall of released contracts pursuant to governing tariffs and/or the reduction in assigned quantities set forth in the Supplier Service Agreement. The recall of Capacity shall be executed in decrements of 200 MMBtus, commensurate with the cumulative reduction in the pro-rata shares of Capacity assigned to the Supplier, rounded to the nearest 200 MMBtus. Each decrement of Capacity assigned to the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative decrease in the pro-rata shares of Capacity recalled from the Supplier.

In the event that a Supplier is declared ineligible to nominate Gas for thirty (30) Gas Days pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such 30 Gas Days, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro-rata shares of Capacity for reassignment.

11.7.5 In the event that a Supplier is disqualified from service for a one (1) full year pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro rata shares of Capacity reassignments.

11.7.6 In the event that the Supplier fails to meet the applicable registration and licensing requirements established by law or regulation, fails to satisfy the requirements and practices as set forth in Section 20.3 of this tariff, fails to be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, fails to make timely payment under the assigned contracts, or fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement, the Company shall have the right to recall permanently any or all Capacity assigned to said Supplier. This section shall also apply to a Customer acting as its own Supplier.

11.7.7 The Supplier shall forfeit its rights to Capacity recalled by the Company pursuant to this Section. Such forfeiture shall be effected in accordance with applicable laws and regulations and the governing tariffs. In the event of Capacity forfeiture pursuant to this Section, the Supplier shall be responsible to compensate the Company for any payments due under the contracts prior to forfeiture, as well as any interest due thereon. The Company will not exercise discretion in the application of the forfeiture provisions of this Section. This section shall also apply to a Customer acting as its own Supplier.

11.8 Seasonal Storage Capacity

11.8.1 On each Assignment Date, the Company shall release Seasonal Storage Capacity to a Supplier that accepts the assignment of Storage Withdrawal Capacity pursuant to Section 11.4. The Company shall assign such Seasonal Storage Capacity consistent with the tariffs governing the release of the associated Storage Withdrawal Capacity.

11.8.2 If the Company assigns Seasonal Storage Capacity to a Supplier pursuant to Section 11.8.1 above, the Company shall transfer in-place Gas inventories to the Supplier. The quantity of inventories to be transferred from the Company to the Supplier shall be determined by multiplying the incremental Seasonal Storage Capacity assigned to the Supplier on the Assignment Date times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be charged the Company's weighted average cost of inventories in off-system storage facilities for each Dekatherm transferred from the Company to the Supplier. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two Business Days prior to each Assignment Date.

11.8.3 In the event that the Company recalls Storage Withdrawal Capacity from the Supplier pursuant to Section 11.7, the Company shall also recall Seasonal Storage Capacity from the Supplier. The Company shall determine the total Seasonal Storage Capacity to be recalled from the Supplier in accordance with the tariffs governing the Storage Withdrawal Capacity returned to the Company.

11.8.4 If the Company recalls Seasonal Storage Capacity from a Supplier pursuant to Section 11.8.3, the Supplier shall transfer in-place Gas inventories to the Company. The quantity of inventories to be transferred from the Supplier to the Company shall be determined by multiplying the decremental Seasonal Storage Capacity times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be reimbursed at the Company's weighted average cost of inventories in off-system storage facilities as of the Assignment Date, for each Dekatherm transferred from the Supplier to the Company. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two (2) Business Days prior to each Assignment Date.

11.8.5 Seasonal storage inventory percentages shall represent the amount of Seasonal Storage Capacity in each assigned storage resource that is assumed to be filled with inventories as of the first Gas Day of the month following the Assignment Date. Each September, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the storage inventory percentages for each resource that shall be applied to incremental or decremental Seasonal Storage Capacity assignments executed on each of the twelve (12) Assignment Dates beginning in October.

11.9 Company-Managed Supplies

11.9.1 The Company shall provide access to and ascribe cost responsibility for the pro-rata shares of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)], and other contracts that are not assignable to third-parties.

11.9.2 The Supplier's Service Agreement shall set forth the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 11.4 and 11.8.

11.9.3 The Company shall notify the Supplier of the conditions and/or restrictions on the use of Company-Managed Supplies pursuant to the tariffs governing the resources.

11.9.4 The Company shall invoice the Supplier for its pro-rata shares of the demand charges for Capacity contracts assigned to the Supplier as Company-Managed Supplies. The Company shall also flow through to the Supplier all costs, including Supply costs, incurred from the utilization of Company-Managed Supplies on behalf of the Supplier.

11.9.5 The Company shall nominate quantities to the Transporting Pipeline and/or other interstate pipelines and off-system storage operators on behalf of Suppliers to which the Company has assigned Company-Managed Supplies, provided that the requested Nomination conforms to the tariffs governing the resource. The Supplier shall communicate its desired Nomination quantities to the Company subject to the provisions in Sections 9.3 and 10.3 of this tariff.

11.10 Capacity Mitigation Service

11.10.1 Capacity Mitigation Service is available to Suppliers that have been assigned Capacity pursuant to Section 11 of this tariff. Such Suppliers shall have the option to take Capacity Mitigation Service from the Company for contracts that would otherwise be released to the Supplier in accordance with this tariff.

11.10.2 Within five (5) Business Days prior to the Annual Reassignment Date, the Supplier must designate those contracts that would otherwise be released to the Supplier pursuant to Section 11.5, as contracts to be managed by the Company for cost mitigation in accordance with the Company's Capacity Mitigation Service. Such designation will be effective for the period November 1 through October 31. Such notice shall be communicated in accordance with the Supplier's Service Agreement.

11.10.3 The Supplier shall pay to the Company the maximum-tariff rate or lesser rate paid by the Company, including all surcharges, for the Capacity contracts that are retained and managed by the Company. The Company shall bill the Supplier monthly for such charges.

11.10.4 The Company will market Capacity contracts designated by Suppliers for mitigation through the Capacity Mitigation Service. The Supplier shall receive a credit on its bill for Capacity Mitigation Service equal to the pro-rata share of the proceeds earned from the Company in exchange for such contract management. Such credit shall be determined on a contract-specific basis at the end of each Month and will be included in the bill sent to the Supplier in the following Month.

12 BILLING AND SECURITY DEPOSITS

12.1 The Customer shall be responsible for all charges for service furnished by the Company under the Company’s applicable rates, as filed from time to time with the NHPUC, from the time service is commenced until it is terminated. The Company shall provide a single bill, reflecting unbundled charges, to Customers for Sales Service.

12.2 The Company shall offer two billing service options to Customers taking only Delivery Service: standard complete billing service and standard pass-through billing service. The Supplier shall inform the Company of the selected billing option in accordance with the provisions set forth in Section 20.5

12.2.1 Standard Complete Billing Service

The Customer shall receive a single bill from the Company for both Delivery Service and Supplier Service. The Company shall use the rates supplied by the Supplier to calculate the Supplier’s portion of the single bill and integrate this billing within a single mailing to the Customer. The Company may charge a fee to the Supplier for providing this billing service as approved by the NHPUC.

The Supplier shall adhere to the Customer classes and rate structure as specified in the Company's then current Rate Schedule on file with and approved by the NHPUC. The Company shall reasonably accommodate, at the Supplier's expense, different Customer classes or rate structures as agreed to by the Company and the Supplier in the Supplier Service Agreement.

The Company shall provide an electronic file to the Supplier that will, in addition to the usage being billed, contain the calculated Supplier billing amounts for the current billing cycle. Customer revenue due the Supplier shall be transferred to the Supplier in accordance with the Supplier Service Agreement. Upon receipt of Customer payments, the Company shall provide a file for the Supplier summarizing all revenue from Supplier sales which have been received and recorded that day.

If a Customer pays the Company less than the full amount billed, the Company shall apply the payment first to Delivery Service, and if any payment remains, it shall be applied to Supplier Service.

12.2.2 Standard Pass-through Billing Service

The Customer taking Delivery Service shall receive two (2) bills: the Company shall issue one bill for Delivery Service and the Supplier shall issue a second bill for Supplier Service.

The Supplier shall be responsible for the collection of amounts due to the Supplier from the Customer. Customer payment responsibility with Suppliers shall be governed by the particular Customer/Supplier contract.

Within three (3) Business Days following the end of the Customer's billing cycle, the Company shall provide an electronic file for the Supplier that will contain the Customer's usage being billed including the current and previous meter readings.

12.2.3 The Company shall inform a Customer when Supplier Service has been initiated by a Supplier along with information on how the Customer may file a complaint regarding an unauthorized initiation of Service. This information shall be included on the first bill rendered to the Customer after such initiation.

12.2.4 A Customer acting as its own Supplier will be subject to the billing and payment requirements in Section 20.8 of this tariff.

12.2.5 Readings taken by an automated meter reading device will be considered actual readings for billing purposes.

13 SALES SERVICE

13.1 Sales Service is the Commodity service provided by the Company for Customers not electing to subscribe to Supplier Service and shall be provided by the Company, or its designated Supplier, in accordance with this tariff. Each Customer receiving Sales Service shall receive one bill from the Company reflecting delivery and Commodity charges.

13.2 A Customer receiving Sales Service on March 14, 2000 shall continue to receive Sales Service unless the Customer elects to take Supplier Service and until such time that Supplier Service is initiated for the Customer in accordance with Section 20.5 of this tariff. If the Customer terminates Supplier Service, if a Supplier terminates service to the Customer, or if the Customer's designated Supplier becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide Sales Service to the Customer. Pursuant to Section 20.5 of this tariff, the Company will initiate Sales Service for the Customer and will provide Sales Service to the Customer until such time that Supplier Service is initiated for the Customer by a new Supplier.

13.3 Any Customer whose Supplier has been assigned Capacity on behalf of said Customer pursuant to Section 11 of this tariff may elect to return to Sales Service if the Customer is no longer receiving Supplier Service. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until such time that Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to said Customer up to a maximum daily level of Gas Usage not to exceed the Total Capacity Quantity ("TCQ") of recallable Capacity assigned to the Customer's former Supplier.

13.4 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff terminates Supplier Service to the Customer, the Customer may select another Supplier. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to the Customer up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's former Supplier.

13.5 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide the Customer with Sales Service up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's Supplier.

13.6 The Company shall be under no obligation to provide Sales Service to a Customer at a maximum daily level in excess of the TCQ of recallable Capacity assigned to a Supplier on behalf of the Customer. The Company may elect to provide Sales Service to the Customer if, and to the extent that, adequate system Capacity and Supplies are available and upon the same terms and subject to the same conditions as any new Customer seeking to take Sales Service.

14 PEAKING SERVICE

14.1 Applicability

Section 14 of this tariff applies to all Suppliers, and to all Customers acting as their own Supplier, that have been assigned, or have elected to be assigned, Capacity on behalf of themselves or Customers in their Aggregation Pools pursuant to Section 11 of this tariff.

14.2 Character of Service

14.2.1 Peaking Service shall be provided by the Company subject to an executed Supplier Service Agreement that sets forth the Maximum Daily Peaking Quantity ("MDPQ") and the assigned Peaking Supply for each of the Supplier's Aggregation Pools.

14.2.2 The Company shall provide quantities of Gas, at the Supplier's request, from the Supplier's Peaking Service Account as established in accordance with Section 14.4. Such quantities shall be deemed delivered by the Company and received by the Company at the Designated Receipt Point(s) for the Aggregation Pool. Peaking Service shall be firm and available to the Supplier each Gas Day in accordance with the balance of the Supplier's Peaking Service Account and the parameters of the Company's Peaking Service Rule Curve.

14.3 Rates and Charges

14.3.1 The applicable rates for Peaking Service shall be established in the Company's tariff. The Supplier shall pay a peaking demand charge based on its MDPQ of assigned Peaking Capacity as billed by the Company for the Peak Season. Such unit demand charge shall be equal to the total Capacity costs and other fixed costs associated with the Company's peaking resources, excluding costs collected through Delivery rates, divided by the estimated peaking resources needed to meet the Company's total system Peak Day requirement.

14.3.2 The Supplier shall pay a Commodity charge equal to the estimated weighted average cost of peaking supplies, including fuel retention and carrying charges. The Company shall communicate electronically, by facsimile or by other agreeable alternative means the Company's estimated weighted average cost of peaking supplies by the 15th of the month preceding the next Assignment Date. The Commodity charge will be multiplied by the volumes of Peaking Service Gas nominated by the Supplier during each Month.

14.4 Peaking Supply

14.4.1 The Customer's portion of the Peaking Supply that shall be assigned to the Supplier on behalf of the Customer shall be equal to the Peaking Supply multiplied by the ratio of the Customer's MDPQ to the aggregate MDPQ of the total system.

14.4.2 On each Assignment Date, the Company shall assign Peaking Supply to a Supplier whose MDPQ has been increased pursuant to Section 11.4. If the Company assigns incremental Peaking Supply to a Supplier, the Company shall credit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount credited to the Supplier's Peaking Service Account shall be determined by multiplying the incremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.3 On each Assignment Date, the Company shall recall Peaking Supply from a Supplier whose MDPQ has been decreased pursuant to Section 11.7. The Company shall determine the Supplier's total Peaking Supply for recall to be equal to the difference between the cumulative total Peaking Supply assigned to the Supplier as of the previous Assignment Date and the total Peaking Supply that is assignable to the Supplier in accordance with Section 14.4.1 above.

14.4.4 If the Company recalls Peaking Supply from a Supplier pursuant to Section 14.4.3, the Company shall debit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount debited from the Supplier's Peaking Service Account shall be determined by multiplying the decremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.5 The peaking inventory percentage shall represent the level of Peaking Supply assumed to be available to a Supplier in its Peaking Service Account as of the first Gas Day of the Month following the Assignment Date for incremental and decremental assignments of Peaking Supply. Each September, the Company shall communicate electronically, by facsimile or by other agreeable alternative means the Peaking Inventory Percentages that shall be applied to incremental or decremental Peaking Supply assignments executed on each of the twelve (12) Assignment Dates beginning in October.

14.4.6 On each Annual Reassignment Date, the Company shall reset the balance in the Supplier's Peaking Service Account to equal the total Peaking Supply assignable to the Supplier on behalf of Customers enrolled in its Aggregation Pool (as of the first Gas Day of the Month following the Annual Reassignment Date) as determined in accordance with Section 14.4.1 above.

14.5 Nomination of Peaking Service

14.5.1 The Supplier shall nominate with the Company the quantity of Peaking Supply, not in excess of the amount determined pursuant to Section 14.4.2, that the Supplier desires to be provided from its Peaking Service Account for the applicable Gas Day. For an Aggregation Pool of Customers taking daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 9.3 of this tariff. For an Aggregation Pool of Customers taking non-daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 10.3 of this tariff.

14.5.2 In response to a valid Nomination for Peaking Service, the Company shall provide the requested quantity of Gas, which shall be deemed to be delivered by the Company and received by the Company at the Designated Receipt Point(s) of the Supplier's Aggregation Pool, subject to the limitations herein. Nominated quantities shall be included in the determination of receipts at the Designated Receipt Point(s) for the Supplier's Aggregation Pool which factors into the daily balancing provisions set forth in this tariff.

14.5.3 The Company may reject a Supplier's Nomination for Peaking Service if the nominated quantity would cause the balance of the Supplier's Peaking Service Account to fall to a level that is 10% or more below the minimum allowable account balance for the Month in which the Nomination is requested, as computed in accordance with the Peaking Service Rule Curve. Under such circumstances, the Company shall require the Supplier to nominate the pipeline and/or storage resources, within the contract entitlements assigned to the Supplier under Section 11, required to maintain the Supplier's Peaking Service Account above the minimum allowable account balance described above. The balance of the Supplier's Peaking Service Account may not in any event fall below zero (0).

14.5.4 The Company shall provide Peaking Service supplies to the Supplier only when the volumes in the Peaking Service Account for the Aggregation Pool are greater than zero (0).

14.6 Peaking Service Critical Day Provisions

14.6.1 In the event that the volumes in a Supplier's Peaking Service Account for an Aggregation Pool are reduced to a level below the minimum allowable account balance as computed in accordance with the Company's Peaking Service Rule Curve, the Company may issue an OFO to such Supplier pursuant to Section 16 of this tariff.

14.6.2 In the event that the total volumes of all Peaking Service Accounts within one or more of the Company's Gas Service Areas are reduced to levels below the total minimum allowable account balances as computed in accordance with the Company's Peaking Service Rule Curve, the Company may declare a Critical Day and issue a blanket OFO pursuant to Section 16 of this tariff.

14.6.3 If, on a Critical Day, the Company projects, based on the Supplier's Nominations, that the Supplier's scheduled deliveries to the Designated Receipt Point(s) of an Aggregation Pool are less than the maximum feasible volumes for deliveries on the Transporting Pipeline, the Company may issue an OFO to the Supplier in accordance with Section 16 of this tariff.

15 DISCONTINUANCE OF SERVICE

15.1 The Company shall notify a Customer's Supplier of record that it has initiated any applicable billing and termination procedures as prescribed by the NHPUC. In the event that the Company discontinues Delivery Service to a Customer in accordance with the provisions set forth above, the Company shall provide electronic notification to the Customer's Supplier of record upon final billing to the Customer. The Company shall not be liable for any revenue loss to the Supplier as a result of any such disconnection.

16 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS

16.1 In the event of a material and significant threat to the operational integrity of the Company's system, the Company may declare a Critical Day.

16.2 Circumstances constituting a threat to the operational integrity of the system that may cause the Company to declare a Critical Day shall include, but not be limited to: (1) a failure of the Company's distribution, storage, or production facilities; (2) near-maximum utilization of the Company's distribution, storage, production, and Supply resources; (3) inability to fulfill firm service obligations; and (4) issuance of an OFO or similar notice by upstream transporters.

16.3 In the event that the Company has declared a Critical Day, the Company will have the right to issue an Operational Flow Order ("OFO") in which the Company may instruct Suppliers to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system, within the contract entitlements, if any, assigned to the Supplier under Section 11 hereof. An OFO may be issued on a pipeline or point-specific basis. An OFO may be issued by the Company as a blanket order to all Suppliers or to an individual Supplier whose actions are determined by the Company to jeopardize system integrity. The Company may issue an OFO to an individual Supplier if the Company faces Gas cost exposure in excess of daily cashout or imbalance penalties as set forth in Sections 9.6, 9.7, 10.6, and 10.7 for any under-deliveries or over-deliveries caused by that Supplier.

16.4 The Company will provide the Supplier with as much notice as is reasonably practicable of the issuance and removal of a Critical Day or an OFO; under most circumstances, the Company intends to provide at least twenty-two (22) hours' notice prior to the start of the Gas Day for the issuance of the Critical Day or OFO. Notification of the issuance and removal of a Critical Day or an OFO will be made by means as established in the Supplier Service Agreement. The Supplier will be responsible for coordinating with its Customers any change to the Customer's quantity of Gas Usage. An OFO or Critical Day will remain in effect until its removal by the Company.

16.5 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an OFO will be subject to the Critical Day provisions of Sections 9.6 and 10.6 of this tariff.

17 FORCE MAJEURE AND LIMITATION OF LIABILITY

17.1 Neither the Company nor the Supplier will be liable to the other for any act, omission, or circumstance occasioned by or in consequence of any event constituting force majeure, and unless it is otherwise expressly provided herein, the obligations of the Company and the Supplier then existing hereunder will be excused during the period thereof to the extent affected by such event of force majeure, provided that reasonable diligence is exercised to overcome such event. As used herein, force majeure will mean the inability of the Company or the Supplier to fulfill its contractual or regulatory obligations: as a result of compliance by either party with an order, regulation, law, code, or operating standard imposed by a governmental authority; by reason of any act of God or public enemy; by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, or breakage or accident to machinery or pipeline (which breakage or accident is not the result of the negligence or misconduct of the party claiming force majeure); by reason of any declaration of force majeure by upstream Transporting Pipelines; or by reason of any other cause, whether the kind enumerated herein or otherwise, not within the control of the party claiming force majeure and which by the exercise of reasonable diligence such party is unable to prevent or overcome. Notwithstanding the foregoing, the Customer's and the Supplier's obligation to make any payments required under this tariff will in no case be excused by an event of force majeure. Nor will a failure to settle or prevent any labor dispute or other controversy with employees or with anyone purporting or seeking to represent employees be considered to be a matter within the control of the party claiming excuse. The party claiming force majeure will, on request, provide the other party with a written explanation thereof and of the remedy being undertaken.

17.2 The Company shall be liable only for direct damages resulting from the Company's conduct of business when the Company, its employees, or agents have acted in a negligent or intentionally wrongful manner. In no event shall the Company be liable to any party for any indirect, consequential, or special damages, whether arising in tort, contract, or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under this tariff or in accordance with or required by law, including, without limitation, termination of the Customer's service.

17.3 If the Company is unable to render firm Delivery Service to the Customer taking such service as contemplated by this tariff as a result of force majeure and such inability continues for a period of thirty (30) Gas Days, the Customer may provide written notice to the Company of its desire to terminate Delivery Service at the expiration of thirty (30) Gas Days from the Company's receipt of such notice, but no sooner than sixty (60) Gas Days following the outset of the force majeure. If the Company has not restored Delivery Service to the Customer at the end of such notice period, the Customer's Delivery Service will terminate and both parties will be released from further performance hereunder, except for obligations to pay sums due and owing as of the date of termination.

17.4 The Company and the Supplier shall indemnify and hold the other and their respective affiliates, and the directors, officers, employees, and agents of each of them (collectively, "affiliates") harmless from and against any and all damages, costs (including attorney's fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively, "liabilities"), resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of either party in connection with the performance of the indemnifying party's obligations under this tariff. The Company and the Supplier shall waive recourse against the other party and its affiliates for or arising from the non-negligent performance by such other party in connection with the performance of its obligations under this tariff.

18 CURTAILMENT

18.1 Whenever the integrity of the Company's system or the Supply of the Company's Customers taking Sales Service or Delivery Service is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole reasonable judgment, curtail or interrupt Gas service or reduce pressure as set out in Section 18, Supply and Capacity Shortage Allocation Policy of this tariff. Such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect. The Company will use efforts reasonable under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

18.2 The Company shall communicate notice of curtailment as soon as practicable to the Suppliers of affected Customers by means as specified in the Supplier Service Agreement.

18.3 The Company shall take reasonable care in providing regular and uninterrupted service to its firm Customers, but whenever the Company deems that the situation warrants any interruption or limitation in the service to be rendered, such interruption or limitation shall not constitute a breach of the contract and shall not render the Company liable for any damages suffered thereby by any person, or excuse the Customer from further fulfillment of the contract.

18.4 In any case where the Company determines in its judgment that a curtailment or interruption of firm services is necessary, the Company will curtail and/or interrupt firm Delivery Service and Sales Service Customers on a nondiscriminatory basis.

19 TAXES

19.1 In the event a tax of any kind is imposed or removed by any governmental authority on the distribution of Gas or on the gross revenues derived from the distribution of Gas at retail (exclusive, however, of taxes based on the Company's net income), the rate for service herein stated will be adjusted to reflect said tax. Similarly, the effective rate for service hereunder will be adjusted to reflect any refund of imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental or regulatory authorities.

19.2 The Customer will be responsible for all taxes or assessments that may now or hereafter be levied with respect to the Gas or the handling or subsequent disposition thereof after its delivery to the Delivery Point. However, if the Company is required by law to collect and/or remit such taxes, the Customer will reimburse the Company for all amounts so paid. If the Customer claims exemption from any such taxes, the Customer will provide the Company in writing its tax exemption number and other appropriate documentation. If the Company collected any taxes or assessments from the Customer and is later informed by the Customer that the Customer is exempt from such taxes, it shall be the Customer's responsibility to obtain any refund from the appropriate governmental taxing agency.

19.3 The Supplier will be responsible for all production, severance, ad valorem, or similar taxes levied on the production or transportation of the Gas before its delivery to the Designated Receipt Point. The Supplier will also be responsible for sales taxes imposed on Gas delivered for the Customer's account. However, if the Company is required by law to remit such taxes to the collecting authority, it will do so and invoice the Supplier for such taxes paid on the Supplier's behalf.

20 SUPPLIER TERMS AND CONDITIONS

20.1 Applicability

The following terms and conditions shall apply to every Supplier providing Supplier Service in the State of New Hampshire, to every Customer doing business with said Suppliers, and to Customers acting as their own Supplier.

20.2 Obligations of Parties

20.2.1 Customer

Unless otherwise agreed to by the Company and the Customer, a Customer shall select one Supplier for each account at any given time. A Customer electing Supplier Service must provide the selected Supplier with its applicable Authorization Number. A Customer may choose only a Supplier who meets the terms described in Sections 20.2.3 and 20.3 below and who meets any applicable registration requirements established by law or regulation.

20.2.2 Company

The Company shall deliver Customer purchased Gas from the Designated Receipt Point to the Delivery Point in accordance with the service selected by the Customer pursuant to this tariff and, among other things, shall:

(a) Provide Customer service and support, including call center functions, for services provided by the Company under this tariff;

(b) Respond to service interruptions, reported Gas leaks, and to other Customer safety calls;

(c) Handle connections, curtailments, and terminations for services provided by the Company under this tariff;

(d) Read meters;

(e) Submit bills to Customers for Delivery Service and if contracted by the Supplier, for Supplier Service in accordance with Section 12.2.1.

(f) Address billing inquiries for Delivery Service;

(g) Answer general questions about Delivery Service;

(h) Provide to Suppliers, on request, the data format and procedures for electronic information transfers and funds transfers;

(i) Arrange for or provide Sales Service to the Customer at the request of the Customer in accordance with the Company's tariff; and

(j) Provide information regarding, at a minimum, rate tariffs, billing cycles, Capacity assignment methods, and Consumption Algorithms.

20.2.3 Supplier

The Supplier shall act on behalf of the Customer to acquire Supplies and to deliver them to the Designated Receipt Point pursuant to the service selected by the Customer and the requirements of this tariff.

The Supplier is responsible for enrolling Customers pursuant to Section 20.5 of this tariff.

The Supplier must request, complete and sign a Supplier Service Agreement to act as a Supplier on the Company's system, satisfy the Supplier requirements and practices as set forth in Section 20.3 of this tariff, be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign Capacity, if any, under Section 11, and be and remain eligible to provide service to Customers in New Hampshire.

The Supplier is responsible for completing all transactions with the Company and for all applicable charges associated with Customer enrollment and changes in the Customer's service as set forth in Section 20.5 and Attachment B.

20.3 Supplier Requirements and Practices

20.3.1 The Company shall have the right to establish reasonable financial and non-discriminatory credit standards for qualifying Suppliers. Accordingly, in order to serve Customers on the Company's system, the Supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three (3) years, as well as two (2) trade and two (2) banking references. To the extent that such annual reports to shareholders are not publicly available, the Supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies, and subsidiaries. The Supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The Supplier shall be subject to a credit investigation by the Company. The Company shall review the Supplier's financial position periodically.

20.3.2 The Supplier shall also confirm in the Supplier Service Agreement that:

(a) The Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) The Supplier is not aware of any change in business conditions which would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) The Supplier has no delinquent balances outstanding for services previously provided by the Company, and the Supplier has paid its account according to the established terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding which would materially affect the Supplier's ability to remain solvent as a business entity.

(e) The Supplier's New Hampshire business advertising and marketing materials conform to all applicable state and federal laws and regulations.

20.3.3 In the event the Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company shall require the Supplier to provide one of the following at the Maximum Financial Liability as calculated below:

(a) Advance deposit;

(b) Letter of credit;

(c) Surety bond; or

(d) Financial guaranty from a parent company that meets the creditworthiness criteria.

The Company shall base the Supplier's maximum financial liability as two (2) times the highest month's aggregated Gas Usage of all Customers currently served by the Supplier at the highest Monthly Index in the preceding twenty-four (24) Months. This amount may be updated continuously, and at minimum, whenever the aggregated Gas Usage of all Customers served by the Supplier changes by more than 25%. The Supplier agrees that the Company has the right to access and apply the deposit, letter of credit, or bond to any payment of any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other amounts owed to the Company, or to secure additional Gas supplies, including payment of the costs of the Gas supplies themselves, the cost of transportation storage, and other related costs incurred in bringing those Gas supplies into the Company's system. The Supplier shall continue its obligation to maintain its financial security instrument until it has satisfied all of its outstanding claims with the Company. The Supplier's financial security as established above must be in place no later than five (5) Business Days prior to the first day of each calendar month in order for the Supplier to maintain its eligibility to provide service to Customers.

20.3.4 The Supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of Supplies which it desires the Company to transport to its Customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these Gas supplies to the Designated Receipt Point.

20.3.5 The Supplier shall warrant to the Company that it has good title to or lawful possession of all Gas delivered to the Company at the Designated Receipt Point on behalf of the Supplier or the Supplier's Customers. The Supplier shall indemnify the Company and hold it harmless from all suits, actions, debts, accounts, damages, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said Gas.

20.3.6 The Supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates, or permits to enable Gas to be delivered to the Company's system.

20.3.7 By agreeing to provide service under this tariff, the Supplier acknowledges that adherence to any applicable law regarding unfair trade practices, truth in advertising law, or law of similar import is required. Any Supplier found by a court of competent jurisdiction to have willfully or repeatedly violated the New Hampshire Consumer Protection Act, N.H.R.S.A. Ch. 358-A; the Federal Trade Commission Telemarketing Sales Rules, 16 C.F.R. Part 310; or the regulations promulgated pursuant to the Federal Trade Commission Act, 15 U.S.C. § 45 (a) (1), may be suspended or disqualified from acting as a Supplier on the Company's system.

20.3.8 If the Supplier fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement (e.g., failure to deliver Gas or late payment of bills rendered or failure to execute a capacity assignment), the Company maintains the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system. Written notice of such an intent to terminate the Supplier's eligibility shall be given to the Supplier, its Customers, and the NHPUC. Notification to the Supplier shall be via Registered U.S. Mail - Return Receipt Requested or other means of documented delivery. Upon issuance of such written notice, the Company shall have the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system at the expiration of ten (10) Gas Days after the giving of such notice, unless within such ten (10) Gas Day period the Supplier shall remedy to the full satisfaction of the Company such failure. Termination of such Supplier eligibility for any such cause shall be a cumulative remedy as to the Company, and shall not release the Supplier from its obligation to make payment of any amount or amounts due or to become due from the Supplier to the Company under the Company's applicable tariffs. Customers whose Supplier's deliveries have been terminated will be placed on Sales Service pursuant Section 13 of this tariff.

20.4 Access to Usage History and Current Billing Information

The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to requesting the Company to release the Company's historic usage information specific to that Customer to such Supplier.

The Company shall be required to provide the most recent twelve (12) months of a Customer's historic usage data to a Supplier, provided that the Supplier has received the appropriate authorization as set forth above.

20.5 Enrollment, Cancellation, and Termination of Supplier Service

20.5.1 The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to initiating Supplier Service to the Customer.

20.5.2 The Supplier must provide the Company with the following minimum information in the Company's predetermined format prior to the commencement or termination of service by the Supplier pursuant to Section 20.5 of this tariff:

(a) The Customer's name and current Authorization Number;

(b) The name of the Supplier;

(c) The Customer's billing option (for commencement of service);

(d) The type of change in Supplier Service (e.g., commencement of service, termination of service, or cancellation of service due to the rescission of an agreement with the Supplier by the Customer); and

(e) Any additional information reasonably required by the Company.

The Company shall determine whether each Customer's enrollment request as provided by a Supplier is complete and accurate, and matches the Customer's account record. In the event that the enrollment request is incomplete, inaccurate, or does not match the Customer's account record, then the Company will notify the Supplier so that the Supplier can resolve any discrepancies.

20.5.3 A change in Supplier Service will normally be made on a monthly metering and billing cycle basis, with changes taking effect on the date of the Customer's next scheduled meter read. Enrollment forms must be transmitted no less than ten (10) Business Days prior to the Customer's next scheduled meter read. If more than one Supplier submits a Supplier Service transaction for a given Customer during the monthly billing cycle, the first completed transaction that is received during the cycle shall be accepted. All other transactions shall be rejected. Rejected transactions may be resubmitted after the Customer's next scheduled meter read.

20.5.4 If the Supplier submits information to the Company to terminate Supplier Service to a Customer less than ten (10) Gas Days before the next scheduled meter read, Supplier Service shall be terminated on the date of the Customer's subsequent scheduled meter read. The Company shall confirm the termination date for Supplier Service.

20.5.5 In those instances when a Customer who is receiving Supplier Service from an existing Supplier initiates such service with a new Supplier, the Company shall send the date for the Customer's change in Supplier Service to the existing Supplier. To terminate Supplier Service with a Supplier and to initiate Sales Service, a Customer shall so inform the Company and the Supplier. Supplier Service shall be terminated on the date of the Customer's next scheduled meter read provided that the Company receives notice of such termination no less than ten (10) days in advance of the next scheduled meter read. Where such notice is received by the Company in less than ten (10) days in advance of the next scheduled read, the termination shall be effective as of the date of the following scheduled read. The Company shall send the Customer's termination date for Supplier Service to the Supplier.

20.5.6 A Customer who moves within the Company's service territory shall have the opportunity to notify its existing Supplier that it seeks to continue Supplier Service with said Supplier. Upon such notification, the Supplier may enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer at the new location. The Company shall make the necessary adjustments to the Supplier's affected Aggregation Pools, including but not limited to, changes to Designated Receipt Points, and quantities of Capacity for assignment, if any, pursuant to this tariff and the Supplier's Service Agreement with the Company. In the event that the existing Supplier does not enroll the Customer for Supplier Service at the new location, the Company shall arrange for or provide Sales Service to the Customer.

20.5.7 In those instances when a new Customer moves to the Company's service territory, the Customer's Supplier must enroll the Customer pursuant to the provisions set forth in this

Section in order to initiate Supplier Service for the Customer. Otherwise, the Customer shall receive Sales Service in accordance with Section 13.

20.5.8 The Company may charge fees to the Supplier for processing the transactions described in this Section, as approved by the NHPUC. These fees are included in Attachment D.

20.6 Aggregation Pools

20.6.1 The aggregation of Customer accounts into an Aggregation Pool is limited by the Delivery Service of the respective Customers. Non-daily metered Customers subscribing to Delivery Service under Rate Schedules G-41, G-42, G-51 and G-52 must be aggregated in a separate pool from Customers subscribing to daily metered service under Rate Schedules G-43, G-53, and G-54.

20.6.2 Non-daily metered Customers taking Delivery Service pursuant to Section 10 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.3 Daily metered Customers taking Delivery Service pursuant to Section 9 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.4 A separate Supplier account will be established for each Supplier Aggregation Pool.

20.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

20.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Attachment B.

20.7 Imbalance Trading

20.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company's provision of information on Supplier imbalances for said Month.

20.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.

20.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

20.7.4 Daily imbalance trades must be point-specific on those Gas Days when the Transporting Pipeline required the Company to balance on a point-specific basis.

20.8 Billing and Payment

20.8.1 By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the prior Month. The Company will provide Suppliers with their Customers' consumption data based on estimated or actual meter readings at the appropriate cycle read dates for each Customer in the Aggregation Pool pursuant to Section 12 of this tariff. This data will be provided on a rolling basis as readings or estimates are made.

20.8.2 Calculation of the charges applicable to the Aggregation Pool will be based on aggregated Gas Usage and other such indicators of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, including but not limited to imbalance charges, credits or penalties, shall be billed to the Supplier on a calendar month basis.

20.8.3 The Supplier shall have ten (10) Business Days from the date of such statement to render payment to the Company. The Supplier shall render payment by means of electronic funds transfer to the Company. The late payment rate will apply to all amounts outstanding after ten (10) days.

20.8.4 If the correctness of the Company's bill to the Supplier is questioned or disputed by the Supplier, an explanation should be promptly requested from the Company. If the bill is determined to be incorrect, the Company shall issue a corrected bill. In the event that the Supplier and the Company fail to agree on the amount of the bill, the Supplier may file a complaint with the Commission to resolve such complaint.

21 CUSTOMER DESIGNATED REPRESENTATIVE

21.1 The Customer may appoint a Designated Representative to satisfy or undertake the Customer's duties and obligations; including, but not limited to submitting and/or receiving notices, making nominations, arranging for trades of imbalances, and performing operational and administrative tasks; provided, however, that under no circumstances will the appointment of a Designated Representative relieve the Customer of the responsibility to make full and timely payment to the Company for all Delivery Service provided under this tariff.

21.2 A request by a Designated Representative to the Company that contains the Customer's Authorization Number will be deemed to be confirmation that the Customer has designated such person or entity as a Designated Representative. A Customer may appoint only one (1) Designated Representative per account.

21.3 Under any agency established hereunder, the Company shall rely upon information concerning the applicable Customer's Delivery Service that is provided by the Designated Representative. All such information shall be deemed to have been provided by the Customer. Similarly, any notice or other information provided by the Company to the Designated Representative concerning the provision of Delivery Service to such Customer shall be deemed to have been provided to the Customer. The Customer shall rely upon any information concerning Delivery Service that is provided to the Designated Representative as if that information had been provided directly to the Customer.

21.4 The Customer shall agree to indemnify the Company and hold it harmless from any liability (including reasonable legal fees and expenses) that the Company incurs as a result of the Designated Representative's negligence or willful misconduct in its performance of agency functions on the Customer's behalf.

IV. ATTACHMENTS

1 ATTACHMENT A
Supplier Service Agreement

GAS SUPPLIER SERVICE AGREEMENT

This Agreement made this **[day]** day of **[month]**, 20**[xx]**, between Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, a New Hampshire Corporation with a principal place of business at 15 Buttrick Road, Londonderry, NH 03053 (the "Company") and **[name of supplier]**, a **[state]** company with a principal place of business at **[address]** ("Supplier"). The Company and the Supplier is also individually referred to herein as a "Party" or collectively as the "Parties."

BASIC UNDERSTANDINGS

Whereas, the Company operates as a natural gas local distribution company and provides firm transportation of third- party gas on its distribution system; and

Whereas, the Company's Tariff (the "Tariff") on file with, and approved by, the New Hampshire Public Utilities Commission (the "NHPUC") permits delivery service customers to assign their rights of nominating and scheduling delivery of gas for transportation on the Company's system to a third-party natural gas supplier; and

Whereas, Supplier seeks to nominate and schedule delivery of gas for distribution on the Company's system on behalf of one or more customers taking delivery service from the Company; and

Whereas, the Company's Tariff, Part III, Section 20.2.3, requires Supplier to enter into this Supplier Service Agreement (the "Agreement") with the Company prior to the initiation of Supplier Service, as defined therein; and

Now therefore, the Parties hereto, each in consideration of the agreement of the other, do hereby agree as follows:

I. SCOPE AND APPLICATION

1.0 This Agreement shall be subject to the Company's Tariff as on file with the NHPUC and in effect from time to time. The Company's Tariff and applicable Rate Schedules are hereby incorporated by reference as though directly set forth herein. In the event the terms of this Agreement conflict with the Company's Tariff, the Tariff shall control.

1.1 This Agreement is intended for use between the Company and natural gas suppliers providing service to customers on the Company's distribution system, and may not be waived, altered, amended, or modified, except as provided herein.

1.2 Exhibits A and B, attached hereto and incorporated herein by reference, include additional terms that are a part of this Agreement.

II. DEFINITIONS

2.0 Any capitalized terms used in this Agreement and not defined herein shall be as defined in the Tariff or as stated in the NHPUC's regulations.

III. TERM

3.0 This Agreement shall become effective on the date hereof (the "Effective Date") and shall continue in full force and effect from month to month unless terminated by either Party by written notice given no less than thirty (30) days prior to the desired termination date, or unless otherwise agreed by the Parties. Notwithstanding the foregoing, the Parties agree to abide by all terms of this Agreement until any transactions that are outstanding at the time of termination are completed, including, but not limited to, the payment by Supplier to the Company of any and all outstanding balances.

3.1 Notwithstanding anything to the contrary elsewhere in this Agreement or in the Company's Tariff, any Party, by written notice to the other Party (the "Breaching Party") may terminate this Agreement, in whole or in part, with respect to such Breaching Party or suspend further performance without terminating this Agreement upon the occurrence of any of the following:(a) the Breaching Party terminates or suspends doing business; (b) the Breaching Party becomes subject to any bankruptcy or insolvency proceeding under federal or state law (unless removed or dismissed within sixty (60) days from the filing thereof), or becomes insolvent, becomes subject to direct control of a transferee, receiver or similar authority, or makes an assignment for the benefit of creditors; or (c) the Breaching Party commits a material breach of any of its obligations under this Agreement or the Tariff and has not cured such breach within fifteen (15) days after receipt of a written notice from the other Party specifying the nature of such.

3.2 Consistent with the provisions of Part III, Section 20.3.8 of the Company's Tariff, the Company also maintains the right to terminate the Supplier's eligibility to act as a Supplier. on the Company's system in the event that Supplier fails to comply with or perform any of the obligations on its part established in the Tariff or in this Agreement, including but not limited to, failure to deliver gas or to make payment of amounts due to the Company.

3.3 Notwithstanding the Effective Date, Supplier acknowledges and agrees that the Company is obligated to provide services pursuant to this Agreement only upon full satisfaction, or the Company's express written waiver, of the Conditions Precedent set forth in Article IV of this Agreement.

3.4 No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

3.5 The enumeration of the foregoing remedies shall not be deemed a waiver of any other remedies to which either Party is legally entitled.

IV. CONDITIONS PRECEDENT

4.0 The following requirements shall be conditions precedent to the Company's obligations hereunder:

(a) Supplier shall provide the Company with all information requested in Exhibits A and B attached hereto and incorporated herein;

(b) Pursuant to Part Ill, Section 20.3.1 of the Company's Tariff, the Company shall confirm the Supplier's creditworthiness. In the event that Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company will identify such deficiencies to the Supplier, and the Supplier shall provide financial assurances as required by the Company consistent with the provisions of Part III, Section 20.3.3;

(c) Pursuant to Part Ill, Section 20.2.3 of the Company's Tariff, Supplier shall register with the NHPUC and provide evidence of such to the Company on an annual basis;

(d) Pursuant to Part III, Section 20.2.3 of the Company's Tariff, Supplier shall demonstrate to the Company that it is an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity;

(e) Pursuant to Part Ill, Section 12.2.1 of the Company's Tariff, where Supplier elects to utilize the Standard Complete Billing Services from the Company, Supplier shall furnish to the Company a complete schedule of its relevant rates and rate pricing options for Supplier Service in written form or in an electronic format reasonably acceptable to the Company, at Company's option, no less than ten (10) Business Days prior to initial Customer enrollment for any such rate or prior to a change in Supplier's existing rates or five (5) Business Days prior to a change in rate pricing options.

(f) Prior to Customer Enrollment, Supplier shall successfully complete testing of the business-transaction communication protocols established by the Company, which may include communication by fax or telephone, electronic transactions as specified by the Company, or any other applicable communication requirements set forth by the Company.

V. <u>SUPPLIER CERTIFICATION</u>

5.0 In addition to the requirements listed in Section IV of this Agreement, and pursuant to Part III, Section 20.3.2 of the Company's Tariff, the Supplier hereby affirms the following:

(a) Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) Supplier is not aware of any change in business conditions that would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) Supplier has no delinquent balances outstanding for services previously provided by the Company, and Supplier has paid its account according to the established

terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding that would materially affect Supplier's ability to remain solvent as a business entity.

(e) Supplier's New Hampshire business advertising and marketing materials conform to all applicable New Hampshire state and federal laws and regulations.

5.1 Supplier shall promptly notify Company of any material change in its financial condition as it relates to Supplier's creditworthiness or solvency as a business enterprise.

5.2 In the event that the NHPUC enacts regulations whereby Supplier must register with the NHPUC, Supplier shall notify Company within twenty-four (24) hours in writing in the event that its registration as a Competitive Supplier is acted upon by the NHPUC in such a way that it materially affects Supplier's performance under this Agreement, including but not limited to suspension, revocation, modification, or non-renewal. Consistent with Part III, Section 20.3.8 of the Company's Tariff, revocation or non-renewal of Supplier's registration shall be grounds for immediate termination of this Agreement by Company.

VI. NOMINATIONS AND SCHEDULING

6.0 The Company and Supplier, pursuant to the Company's Tariff on file with the NHPUC and the terms of this Agreement, agree to exchange and act on information regarding the nomination and scheduling of gas for transportation on behalf of Supplier's customers.

6.1 Supplier acknowledges and agrees that its transportation rights under this Agreement are solely those that have been assigned to it by the Customer pursuant to the Company's Tariff. Supplier further agrees that the Company shall have no obligation to honor any nomination or scheduling request from Supplier that, in the Company's sole judgment, exceeds the scope of Supplier's assigned rights or where such nominations or requests could be reasonably refused, directly or indirectly, based on the terms of this Agreement or the Company's Tariff.

6.2 Pursuant to Part Ill, Sections 9.3.2 and 10.3.3 of the Company's Tariff, nominations will be communicated to the Company in accordance with the terms of this Agreement as set forth in Exhibit A.

6.3 In the event of a discrepancy between the volume nominated to the Company by Supplier and the volume confirmed by the Company, the discrepancy shall be allocated between and among Supplier's Aggregation Pools and/or Customers in accordance with the Pre-Determined Allocation Method set forth in Exhibit B, attached hereto. In the event that the Supplier has not provided the Company with a Pre-Determined Allocation Method, the discrepancy will be allocated consistent with the provisions of the Company's Tariff.

VII. CAPACITY ASSIGNMENTS

7.0 The Supplier's Maximum Daily Peaking Quantity ("MDPQ") may be modified during the calendar year in accordance with the provisions of Part Ill, Sections 11.0 and 14.0 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.1 Pursuant to Part III, Section 11.9.2 of the Company's Tariff, the quantity of each Company Managed Supply assigned to Supplier may be modified during the calendar year in accordance with Part III, Sections 11.4 and 11.8 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.2 In accordance with Part Ill, Sections 11.0 and 14.0 of the Company's Tariff, the quantity of Capacity assigned to Supplier may be modified during the calendar year. In addition, the Company shall have the right to adjust a Customer's total capacity quantity C'TCQ") if the Company determines that the TCQ calculation is in error or is otherwise not calculated in accordance with the provisions of Part Ill, Sections 11.3.2.

7.3 Pursuant to Part Ill, Section 11.10.2 of the Company's Tariff, Supplier shall provide notice to the Company of its designation of contracts to be managed by the Company for cost mitigation purposes by the means set forth in Exhibit 8.0.

VIII. LEFT BLANK INTENTIONALLY (RESERVED FOR FUTURE USE)

IX. BILLING AND PAYMENT

9.0 Bills, fees and charges for services provided by the Company, including, but not limited to, monthly cashouts, monthly imbalance charges, daily imbalance charges, and any other applicable charges set forth in the Tariff or in this Agreement, shall be

rendered to Supplier on a monthly basis and shall be due upon receipt of said bill, unless otherwise specified in Exhibit A.

In addition to any other right or remedy available to the Company, Supplier's failure to make payment within ten (10) days of the posting date on the bill shall result in the addition of interest on any unpaid balance calculated at the maximum monthly rate allowable by the Company's Tariff. Interest shall accrue commencing from the date said bill was posted. The posting date is the date the bill is transmitted to Supplier. The bill may also be transmitted electronically if agreed to between the Parties in Exhibit A.

9.1 The Company shall have the right to deduct any amounts owed by Supplier to the Company for such services, which are thirty (30) days or more past due, from any amounts collected in the normal course of business by the Company on the Supplier's behalf. Amounts subject to a good faith dispute will not be subject to deduction.

9.2 The Parties agree to cooperate and provide each other with necessary documentation relating to any transactions resulting hereunder, including but not limited to, applicable sales or other tax exemptions. The Parties agree that Supplier's failure to comply with the provisions of this Article IX shall constitute default of payment under the Tariff and expose Supplier to liability thereunder as well as under this Agreement.

9.3 Consistent with the provisions of Part Ill, Sections 20.3.1 and 20.3.3 of the Company's Tariff, Supplier shall satisfy the creditworthiness standards established by the Company. In the event the Supplier has not demonstrated satisfaction of the Company's creditworthiness standards, the Supplier shall provide, upon ten (10) days written notice from the Company, financial assurance in the form of an advance deposit, letter of credit, surety bond or financial guaranty from a parent company, as reasonably determined by the Company. The amount of any such financial assurance required by the Company shall be calculated in accordance with the provisions of Part III, Section 20.3.3 of the Company's Tariff. The Company shall review Supplier's satisfaction of the Company's creditworthiness standards every twelve (12) months during the term of this Agreement giving consideration to Supplier's payment history in the preceding twelve-month period. Upon the request of Supplier, the Company shall exercise its sole reasonable discretion to determine whether a change in the form of financial assurance is warranted. In the event that the Company requires financial assurances in the form of a deposit, such deposits shall accrue interest in accordance with the Company's Tariff. Such deposit shall be returned to Supplier within thirty (30) days of the expiration or termination of this Agreement, provided that Supplier is not in default under this Agreement. The Company may deduct from the deposit any amount payable to the Company by Supplier under this Agreement, which has not been paid by the Supplier when due, unless such non-payment relates to a documented billing dispute between Supplier and the Company. Such deduction may be taken by the Company without notice or demand of any kind and the Company may, in its sole discretion, apply such deposit against any amount then due and payable. In the event that Company applies all or any portion of such deposit, Supplier shall deposit such sums as are necessary to replenish the security deposit to its maximum amount, within ten (10) days' notice of such deduction and application.

X. REPRESENTATIONS

10.0 Each Party represents that it is and shall remain in compliance with all applicable laws, tariffs, and NHPUC regulations during the term of this Agreement.

10.1 Each person executing this Agreement for the respective Parties represents and warrants that he or she has authority to bind that Party.

10.2 Each Party represents that (a) it has the full power and authority to execute, deliver, and perform this Agreement; (b) the execution, delivery, and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party; and (c) this Agreement constitutes that Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

10.3 Each Party shall exercise all reasonable care, diligence and good faith in the performance of its duties pursuant to this Agreement, and carry out its duties in accordance with applicable recognized professional standards.

XI. NONDISCLOSURE

11.0 Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third Party, including affiliates of such Party, without the express prior written consent of the other Party. As used herein, the term "Confidential Information" shall include, but not be limited to, all business, financial, and commercial information pertaining to the Parties, Customers of either or both Parties, Suppliers for either Party, personnel of either Party; any trade secrets; and other information of a similar nature; whether written or in intangible form that is marked proprietary or confidential with the appropriate owner's name.

11.1 Confidential Information shall not include information known to either Party prior to obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a Party who was under an obligation of confidentiality to the other Party to this Agreement, or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own Confidential Information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information. Each receiving Party shall, upon termination of this Agreement or at any time upon the request of the disclosing Party, promptly return or destroy all Confidential Information of the disclosing Party then in its possession.

11.2 Notwithstanding the preceding, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential Information pursuant to any applicable law, regulation, ruling, or order, provided that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority; and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so that it may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of any injunction to prohibit such disclosure.

11.3 No provision of this Agreement shall prohibit the Company from communicating to its Customers and prospective customers, information regarding Supplier's eligibility to conduct business on the Company's distribution system. In addition, obligations under this Article XI shall survive the termination or expiration of this Agreement.

XII. LIABILITY AND INDEMNIFICATION

12.0 The Parties acknowledge and agree that the Force Majeure provisions set forth in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.1 The Parties acknowledge and agree that the liability and indemnification provisions in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.2 For purposes of such liability and indemnification, however, the Parties acknowledge and agree that nothing in such Tariff prohibits one Party from impleading the other Party as a third-party defendant, whether or not one or both Parties are named as defendants in the initial claim of a third party. The third-party claim shall be stayed pending resolution of any dispute regarding liability and indemnification under this Agreement. Such resolution shall be final and binding upon the Parties only after agreement between the Parties or after entry of a final judgment, after any further appeals of a court of competent jurisdiction to which any appeal may have been taken from the determination of the arbitrator(s).

12.3 The Parties acknowledge and agree that for purposes of Part III, Section 17 the Company's Tariff, a Party seeking recovery from the other Party in connection with the performance of its obligations of the Tariff shall not be entitled to recovery where its own negligent acts or omissions contribute to or cause such damages, costs, fines, penalties or liabilities.

12.4 The Parties expressly acknowledge and agree that the dispute resolution provision in Article XIII of this Agreement shall apply to any and all disputes arising under this Article, including, without limitation, those disputes that arise as a result of either of

the Parties being named as a defendant in the primary action or being named as a third-party defendant by a defendant in the primary action.

12.5 Notwithstanding anything in this Agreement or the Tariff to the contrary, in no event shall any Party hereto be liable to any other Party hereto for indirect, consequential, punitive, special, or exemplary damages under any theory of law that is now or may in the future be in effect, including without limitation: contract, tort, N.H.R.S.A. Ch. 358-A, strict liability, or negligence.

12.6 Notwithstanding the availability of other remedies at law or in equity, either Party hereto shall be entitled to specific performance to remedy a breach of this Agreement by the other Party.

12.7 Supplier further agrees that it shall indemnify, defend and hold harmless the Company with respect to any claim, suit, damages or costs of any kind arising from any action or inaction of the Company in reliance upon the nominations, scheduling instructions or other communications from Supplier. The Parties agree that reliance on such instructions and communications shall be deemed reasonable and shall not constitute negligence.

12.8 The provisions of this Article XII shall survive the termination of this Agreement.

XIII. DISPUTE RESOLUTION

13.0 Disputes hereunder shall be reduced to writing and referred to the Parties' representatives for resolution. The Parties' representatives shall meet and make all reasonable efforts to resolve the dispute. Pending resolution, the Parties shall continue to fulfill their obligations under this Agreement in good faith, unless this Agreement has been suspended or terminated. If the Parties fail to resolve the dispute within thirty (30) days, they may mutually agree to pursue mediation or arbitration to resolve such issues.

13.1 The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of New Hampshire, without regard to the doctrines governing choice of law. All disputes arising hereunder shall be brought either before the NHPUC or the state courts of the State of New Hampshire.

XIV. COMMUNICATIONS

14.0 Except as otherwise provided herein, any notices given under this Agreement shall be in writing and shall be delivered to the Company as set forth in Exhibit A, by hand or sent by (a) certified mail, return receipt requested, first class postage prepaid, (b) telecopy, or (c) a nationally recognized courier service. Notices and other communications to Supplier shall also be addressed as shown on Exhibit A. Notices given hereunder shall be deemed to have been given upon receipt or any refusal to accept; telecopied notices shall be deemed to have been given upon confirmation of their receipt.

14.1 All communications required by the Company's Tariff shall be made in accordance with the schedule listed in Exhibit A. Information on active Company fax numbers and e-mail addresses shall be posted on the Company's Internet Website at http://www.libertyutilities.com/east/gas/business_partners/index.html

XV. ENFORCEABILITY

15.0 In the event that any portion or part of this Agreement is deemed invalid, against public policy, void or otherwise unenforceable by a court of law, the validity and enforceability of the remaining portions thereof shall otherwise be fully enforceable.

15.1 No waiver by any Party of any one or more defaults by the other Party in the performance of any provision of this Agreement shall operate or be construed as a waiver of any other present or future default, whether of a like or different character. No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights.

XVI. ASSIGNMENT AND DELEGATION

16.0 Any entity that shall succeed by purchase, merger or consolidation to the assets and properties, substantially or as an entity, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

16.1 Either Party may, without relieving itself of its obligations under this Agreement, assign any of its rights or obligations hereunder to an affiliated entity, but otherwise no assignment of this Agreement or any of the rights or obligations hereunder shall

be made unless there first shall have been obtained the written consent of the other Party. No assignment by Supplier shall take effect until the assignee has met the requirements of Article IV hereunder. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee.

16.2 The restrictions on assignment contained herein shall not in any way prevent either Party from pledging or mortgaging its rights as security for its indebtedness.

16.3 In addition, either Party may subcontract its duties under this Agreement to a subcontractor provided that the subcontracting Party shall remain fully responsible as a principal and not as a guarantor for performance of any subcontracted duties, and shall serve as the point of contact between its subcontractor and the other Party, and the subcontractor shall meet the requirements of any applicable laws, rules, regulations, and Tariff. The assigning or subcontracting Party shall provide the other Party with thirty (30) calendar days' prior written notice of any such subcontracting or assignment, which notice shall include such information about the subcontractor as the other Party shall reasonably require.

XVII. MISCELLANEOUS

17.0 This Agreement, all Exhibits and attachments hereto and all documents referenced herein, constitute the entire agreement between the Parties and supersedes all other agreements, communications, and representations. Paragraph headings are for convenience only and are not to be construed as part of this Agreement.

17.1 Unless otherwise provided herein, no modification of, or supplement to, the terms and provisions stated in this Agreement shall be or become effective without the written consent of both Parties.

17.2 This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed to be an original but all of which shall constitute one and the same document.

In witness whereof, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the date above.

[SUPPLIER NAME]

By ______________________ Title______________________

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

By ______________________ Title______________________

2 ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$ 0.1200	per MMBtu of Daily Imbalance Volumes")
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of	
III.	Peaking Demand Charge	$ 17.32	MMBTU of Peak MDQ
IV.	Company Allowance Calculation (per Schedule 25)		
		169,030,868	Total Sendout - Therms Jul -2019 - Jun-2020
		166,311,578	Total Throughput - Therms Jul-2019 - Jun-2020
		2,719,290	Variance (Sendout - Throughput)
	Company Allowance Percentage 2020-21	1.6%	Variance / Total Sendout

3 ATTACHMENT C
Capacity Allocators

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	46.1%	17.1%	36.8%	100.0%
G-51	Low Annual /Low Winter Use	59.3%	12.9%	27.9%	100.0%
G-42	Medium Annual / High Winter	46.1%	17.1%	36.8%	100.0%
G-52	High Annual / Low Winter Use	59.3%	12.9%	27.9%	100.0%
G-43	High Annual / High Winter	46.1%	17.1%	36.8%	100.0%
G-53	High Annual / Load Factor < 90%	59.3%	12.9%	27.9%	100.0%
G-54	High Annual / Load Factor < 90%	59.3%	12.9%	27.9%	100.0%

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 20-105

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. D/B/A LIBERTY

Petition for Permanent Rates

Order on Settlement Agreement and Permanent Rates

O R D E R N O. 26,505

July 30, 2021

In this order, the Commission approves a permanent rate increase for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty, effective August 1, 2020.

I. PROCEDURAL HISTORY

On July 31, 2020, Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty (Liberty) filed a Petition for Permanent and Temporary Rates pursuant to RSA 378:27 and 378:28. Liberty also filed a motion for confidential treatment regarding compensation information, customer information, and contract pricing.

On July 8, 2020, the Office of the Consumer Advocate (OCA) filed a letter of participation in this docket pursuant to RSA 363:28.

In Order No. 26,395 (August 19, 2020), the Commission suspended Liberty's proposed tariffs pending further investigation pursuant to RSA 378:6, I(a). In Order No. 26,412 (September 30, 2020), the Commission set temporary rates at existing levels, approved a revenue requirement for the purposes of temporary rates of $92,890,325 with a $4,994,290 increase in allowed revenues accomplished by adjusting the allowed revenue per customer (RPC) amounts for each of Liberty's rate classes, effective October 1, 2020.

On November 20, 2020, Liberty filed a Motion to Amend its petition to include a request for recovery of approximately $7.5 million in costs incurred to investigate, evaluate, and assess the Granite Bridge Liquefied Natural Gas tank and related gas pipeline (Granite Bridge project). Accompanying its filing was a motion for protective order and confidential treatment. On December 18, 2020, the Commission issued a Supplemental Order of Notice relating to Liberty's motion.

On May 24, 2021, Commission Staff, now with the Department of Energy (Energy), on behalf of the parties, filed a letter informing the Commission that a settlement in principle had been reached resolving all issues in this proceeding except for the recovery of costs associated with the Granite Bridge project, which the parties intended to litigate. On May 28, the Commission issued a secretarial letter scheduling separate hearing dates to consider the Granite Bridge project dispute and to consider a settlement agreement as to the other issues in this rate case. On June 7, Liberty filed a motion for confidential treatment for discovery responses. On June 30, Liberty filed a settlement agreement reached between the parties on permanent rates (Settlement Agreement) and attachments. On July 13, the Commission held a duly noticed hearing on the Settlement Agreement.

Liberty's petitions and related filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted on the Commission's website at https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-105.html.

II. POSITIONS OF THE PARTIES

A. Liberty

Liberty's petition requested that the Commission grant: (1) a permanent increase in Liberty's distribution rates effective with service rendered on or after September 1, 2020, designed to yield an increase of $13,497,250 in annual revenue; (2) temporary rates effective with service rendered on or after October 1, 2020, designed to yield an increase of $6,500,000 in annual revenue pending the Commission's final determination on the Company's request for a permanent rate increase; and (3) a step adjustment in rates designed to yield an increase of $5,680,641 in annual revenue to recover costs associated with approximately $38 million of capital expenditures projected to be made during 2020, to be effective no earlier than August 1, 2021. Liberty alleged that under the rates currently in effect, it is unable to earn the rate of return authorized by the Commission.

B. Office of the Consumer Advocate

On March 18, 2021, the Office of the Consumer Advocate (OCA) pre-filed the direct testimony of Pradip Chattopadhyay, Al-Azad Iqbal, and Jerome Mierzwa. The OCA's testimony recommended an ROE of 8.9 percent, did not include a recommendation for a capital structure different from the Company's proposal, and included other proposed adjustments and rate design elements.

C. Department of Energy

On March 18, 2021, Energy filed the direct testimony of Stephen Frink, Randall Woolridge, and Donna Mullinax. Energy's testimony recommended the following: (1) a return on equity of 9.0 percent and a capital structure of 49.21 percent equity and 50.79 percent long term debt; (2) a permanent decrease to revenue requirement of $2,240,114 below the temporary rate level; (3) one step increase for capital expenditures projected to be made during 2020 of $5,157,187, subject to audit, with no step adjustments for future years; and (5) other proposed adjustments.

III. MOTIONS FOR PROTECTIVE ORDER

Liberty moved for orders pursuant to the New Hampshire Code of Administrative Rules, Puc 203.08, to protect portions of its filings and responses to various data requests. Liberty asserted that each of its identified responses are exempt from disclosure under RSA 91 A:5, IV, or RSA 363:38.

In its July 31, 2020 filing Liberty requested confidential treatment of bates page I-120 of its initial filing, which it stated contains employee compensation information for which there is a strong privacy interest with no corresponding public interest. In its November 20, 2020, filing Liberty requested confidential treatment of its Supplemental Testimony at bates pages 18, 20, 23-24, 26-27, and 44-45, which it stated contains confidential pricing information that, if disclosed, would impair its ability to receive competitive pricing in the future and for which there is a strong privacy interest with no corresponding public interest. In its April 29, 2021, filing Liberty requested confidential treatment of: Attachment WJC-MRS-1(c) at Bates II-607 of its rebuttal testimony, which it stated contains confidential pricing information that, if disclosed, would impair its ability to receive competitive pricing in the future; and Attachment WJC/SEM-1, which it stated contains customer information that is confidential pursuant to RSA 363:37-38. In its June 7, 2021, filing Liberty requested confidential treatment of: Confidential Attachments OCA 1-4.e.3,xlsx, Staff 1-8.xlsx, Staff 1-8.1, Staff TS 1.2.b.1, Staff TS 1-2.b.2, and Staff TSTS-1.a.xlsx, which it stated contains customer information that is confidential pursuant to RSA 363:37-38; Confidential Attachments OCA 1-35.xlsx, Staff 1-4.d.2.xlsx, Staff TS 3-8.b.1, Staff TS 3-8.b.2, Staff TS 3-8.b.3, Staff TS 3-8.b.4, Staff TS 3-8.c.xlsx, and Staff TS 2-1 under both RSA 363:38 and RSA 91-A:5 for which there is a strong privacy interest with no corresponding public interest., IV; Confidential Attachments OCA 4-9.b.i.1 through OCA 4-9.b.i.3, OCA 4-

9.b.iii.1 through OCA 4-9.b.iii.5, and Staff 4-5a through Staff 4-5l, which it stated contains confidential information of third parties that is proprietary and competitively sensitive for which there is a strong privacy interest with no corresponding public interest; Confidential Attachments Staff 2-1, t Staff 3-2.1, Staff 3-20.1.zip, Staff 3-20.2.pdf, Staff 3-22.zip[1], Staff 3-23.2.zip, OCA 6-9.2, and Staff TS 3-16, which it stated contains confidential information of Liberty and its corporate affiliates for which there is a strong privacy interest with no corresponding public interest; responses to Staff 3-64, Staff 3-67, and Confidential Attachment Staff TS 3-15.xlsx, which it stated contains confidential employee information which constitutes confidential personnel information for which there is a strong privacy interest with no corresponding public interest; Confidential Attachment Staff 4-3, Staff 5-7.xlsx and its response to OCA 5-6, which it stated contains confidential pricing information that, if disclosed, would impair its ability to receive competitive pricing in the future. Aside from the withdrawn request relating to Staff 3-22.zip, no party objected to Liberty's requests.

IV. SETTLEMENT AGREEMENT

Liberty, the OCA, and Energy (Settling Parties) were signatories to the Settlement Agreement. During the hearing on the Settlement Agreement, testimony was presented by Steven Mullen, David Simek, Heather Tebbetts, Pradip Chattopadhyay, Al-Azad Iqbal, and Donna Mullinax in support of the agreement.

The Settlement Agreement provides for a permanent increase to Liberty's distribution revenue requirement in the amount of $6,294,290, which is a $1.3 million increase above the level approved of in the temporary rates order. Of the total increase, the Settling Parties agreed

[1] At hearing on July 13, 2021, Energy objected to Liberty's request for confidential treatment of the information identified as Staff 3-22.zip, Liberty withdrew its request for confidential treatment of this information in its cover letter accompanying its responses to Record Requests on July 16, 2021.

that $1,993,587 of the permanent increase shall be applied to the next cost of gas proceeding, along with a reconciling surcharge added to Liberty's Local Distribution Adjustment Clause. The remainder of the revenue requirement increase, $4,394,290, would be collected through distribution rates for service rendered effective August 1, 2021, and reconciled back to the effective date of temporary rates. Because the temporary rate revenue increase was an increase of $4,994,290, the result is that the permanent rate change shall be a decrease of approximately $600,000 from temporary rates.

Regarding rate base, the Settlement Agreement provides for 25.72 lead/lag days in cash working capital, commitments to study cost of removal in 2021 and depreciation based on 2021 numbers which shall be reflected in the second step increase, and for treatment of Liberty's excess accumulated deferred income tax liabilities.

The Settlement Agreement provides for a return on equity of 9.3 percent and a capital structure of 52 percent equity and 48 percent long term debt. The Settlement Agreement allows Liberty two step adjustments, the first for certain capital projects placed in service during calendar year 2020, effective on August 1, 2021, and capped at a $4.0 million increase to annual distribution revenue. The second step adjustment would be for certain capital projects placed in service during calendar year 2021, and shall be effective August 1, 2022, and capped at a $3.2 million annual increase to distribution revenue. Additionally, the Settlement Agreement contains a provision restricting Liberty's next rate case test year to be no sooner than the twelve-month period ending December 31, 2022.

The Settlement Agreement includes a local property tax adjustment mechanism, which the settling parties assert is consistent with RSA 72:8-e. The mechanism would allow Liberty recovery or refund of local property tax expenses that differ from the amount included in base rates, beginning with the April 1, 2020 tax year.

The Settlement Agreement contains new provisions relating to the costs associated with the Keene propane to compressed natural gas (CNG) conversion, including allowing Liberty to recover one-half of the incrementally higher CNG supply costs as compared to the propane supply cost, definitional terms relating to the Keene Phase 1 project, and a provision for cost recovery in the second step adjustment. The Settlement Agreement also contains provisions resulting in reduction to the revenue requirement relating to the continuation of the risk sharing mechanism for the Pelham Expansion project and iNATGAS CNG facility. The recovery of costs associated with the Granite Bridge project are excluded from the Settlement Agreement.

The settling parties included provisions relating to Liberty's decoupled rate structure designed to clarify the decoupling mechanism and associated tariff language. Those provisions include five key points relating to 1) revenue per customer calculations; 2) incremental revenue per customer calculations; 3) the Managed Expansion Program premium; 4) a Revenue Decoupling Adjustment on Liberty's balance sheets; and 5) the revenue per customer calculation reporting requirements. The settling parties also agreed to review regulatory reporting requirements, and discuss areas for potential elimination, consolidation, and decreased frequency of those reporting requirements.

Lastly, the Settlement agreement contains provisions relating to recoupment of rate case expenses and revenue reconciliation. Under the terms of the Settlement Agreement, Liberty is authorized to recover an estimated $856,864.64 in rate case expenses beginning November 1, 2021 through the Local Distribution Adjustment Clause mechanism, subject to review and approval by the Commission. In reconciling temporary rates to permanent rates, Liberty shall return an estimated $570,933 through the Local Distribution Adjustment Clause mechanism, subject to review and approval as part of a through the Local Distribution Adjustment Clause proceeding.

V. COMMISSION ANALYSIS

Settlement Agreement

The Commission is authorized to fix rates after a hearing, upon determining that rates, fares, and charges are just and reasonable. RSA 378:7. In circumstances where a utility seeks to increase rates, the utility bears the burden of proving the necessity of the increase pursuant to RSA 378:8. In determining whether rates are just and reasonable, the Commission must balance the customers' interest in paying no higher rates than are required against the investors' interest in obtaining a reasonable return on their investment. *Eastman Sewer Company, Inc.*, 138 N.H. 221, 225 (1994). In this way, the Commission serves as arbiter between the interests of customers and those of regulated utilities. *See* RSA 363:17-a; *see also EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 25,202 at 17 (March 10, 2011).

Pursuant to RSA 541-A:31, V(a), informal disposition may be made of any contested case at any time prior to the entry of a final decision or order, by stipulation, agreed settlement, consent order, or default. Puc 203.20(b) requires the Commission to determine, prior to approving disposition of a contested case by settlement, that the settlement results are just and reasonable and serve the public interest.

In general, the Commission encourages parties to attempt to reach a settlement of issues through negotiation and compromise, as it is an opportunity for creative problem solving, allows the parties to reach a result more in line with their expectations, and is often a more expedient alternative to litigation. *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No.

25,202 at 18 (March 10, 2011). Even where all parties join a settlement agreement, however, the Commission cannot approve it without independently determining that the result comports with applicable standards. *Id*. As the Settlement Agreement pertains to a rate case, the underlying standard to be applied is whether the resulting rates are just and reasonable. RSA 378:7.

We note that the Settlement Agreement purports to resolve all matters in this docket with the exception of the Granite Bridge Project, which the parties agreed to litigate separately. The Commission accepted the parties' effective bifurcation of issues though secretarial letter scheduling separate hearings on the different issues. The Commission held separate hearings related to the recovery costs of the Granite Bridge project on June 7^{th} and 8^{th}, 2021. In this order we consider the terms of the Settlement Agreement only; the dispute regarding recovery of costs associated with the Granite Bridge Project will be addressed in a subsequent order.

The Settlement Agreement calls for an overall permanent revenue requirement increase of $6,294,290, which is a $1.3 million increase above the level provided by temporary rates. The Settlement Agreement also contemplates two step adjustments. The first step adjustment is capped at $4,000,000 for 2020 capital investments placed in service on or before December 31, 2020, and the second step adjustment is capped at $3,200,000 for 2021 capital investments placed in service on or before December 31, 2021.

We note the Settlement Agreement contemplates a process for review and Commission approval of the second step adjustment, while no process is provided for the first step adjustment. Implicit authorization of a company's first step adjustment through a hearing on a rate case settlement agreement is not in keeping with this Commission's recent practice, and assumes approval of the settlement agreement. *See, e.g.,* filings of May 26, 2020, in Docket No. DE 19-064 (Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities concurrently filed settlement agreement and request for first step adjustment); filings of October 9, 2020, in Docket No. DE 19-057 (Public Service Company of New Hampshire d/b/a Eversource Energy concurrently filed settlement agreement and request for first step adjustment). Additionally, we note that subsection 5.5 affords the parties to the Settlement Agreement the ability to contest the prudence of individual investments within the step *increases*. Since the Commission has not reviewed the non-growth projects placed in service in 2020 (Exhibit 49, bates page 28) in detail, we cannot determine prudence of the first step.

We compare the amounts to the revenue increase sought by Liberty (a revenue increase of $13,497,250 plus a 2020 step adjustment of $5,680,641 together with a request yearly step adjustments for capital expenditures placed in service in 2021 and 2022), to that originally recommended by Energy ($2,240,114 revenue decrease below the temporary rate level with one step adjustment for $5,157,187). From that comparison, we understand that the amount of the revenue increase in the Settlement Agreement represents a negotiated amount that the Settling Parties agreed will provide the Company the revenues necessary to provide safe and reliable service.

The Commission notes that Liberty's approved distribution revenue from the time of its acquisition of EnergyNorth in 2012 (Order No. 25,370 (May 30, 2012)) to the present has resulted in an average annual increase of 7.3%, while the customer base has grown only 1.4% per year.

The Commission notes further the Company's actual debt/equity ratio of 43.6% Long-Term Debt and 56.4% Equity, and the Settlement Agreement of 48% Long Term Debt and 52% Equity. We encourage Liberty to review its capital structure in light of a low cost-of-debt macroeconomic environment in anticipation of future rate cases. We also note that the agreement results in a return on equity of 9.3% and return on debt of 4.42%.

Based on the evidence before us, we find the capital structure, overall rate of return, and return on equity to be reasonable, though we anticipate gradual movement toward more debt in the cost of capital moving forward. In an increased debt regime, equity would be lower and may result in a higher return on equity than currently contemplated. We also note that the return on equity we are approving is within the scope of recent equity returns approved by the Commission, a reasonable but by no means definitive indication of an appropriate return on equity. *See Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia*, 262 U.S. 679 (1923) and *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), *see, e.g.*, *Public Service Company of New Hampshire d/b/a/ Eversource Energy*, Order No. 26,433 at 19 (December 15, 2020) (approving a return on equity of 9.3 percent); *Liberty Utilities (EnergyNorth Natural Gas) Corp., d/b/a Liberty Utilities*, Order No. 26,122 at 43 (April 27, 2018) (approving a return on equity of 9.3 percent); *Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities*, Order No. 26,376 at 12 (June 30, 2020) (approving a return on equity of 9.1 percent).

The record before us included testimony made under oath and adopted during the hearing that was sufficient to make the required findings relating to the permanent rate increase based on the test year of 2019 proposed in the Settlement Agreement. We have reviewed the record and conclude that the Settlement Agreement balances the interests of the customers' desire to pay no higher rates than reasonably necessary and the investors' right to earn a reasonable return on their investment. *See Eastman Sewer Company, Inc.*, 138 N.H. 221, 225 (1994). Accordingly, we find the resulting increase to permanent rates to be just and reasonable as required by RSA 374:2 and RSA 378:28.

With respect to the Property Tax Adjustment Mechanism described in the Settlement Agreement, we find its terms to be consistent with the requirements of RSA 72:8-e, and find the terms relating to filing deadlines and recoupment periods contained in the Settlement Agreement to be acceptable. *See* RSA 72:8-e, II.

Although we recognize the proposed Settlement Agreement represents a global settlement of all issues in this proceeding by parties with diverse interests, and we generally agree that the settlement results are just and reasonable and serve the public interest, we approve the Settlement Agreement subject to the following conditions:

1) With respect to the Settlement Agreement's provision for the recovery of rate case expenses, we understand the $856,864.64 figure provided is an estimate that is subject to our review and approval. We emphasize that the Commission's approval of rate case expenses is based on the criteria identified in Puc Ch. 1900, and contingent on our independent finding that the expenses to be recovered are just and reasonable and in the public interest. *See* Puc 1901.01(b). Our approval of the Settlement Agreement is not a finding that Liberty has met its burden to prove that its rate case expenses have met this standard.
2) With respect to the first step adjustment, for plant placed in service during 2020, we accept the provision allowing for and capping such an adjustment at $4.0 million, however we reject its implementation on August 1, 2021, contemporaneously with the distribution rates approved by this order. For the reasons stated above, we direct Liberty not to collect any revenue requirement associated the first step adjustment until it files a related request with the Commission containing the same level of detail as specified in the Settlement Agreement for the second step increase and specifically

identifying which projects shall be considered for prudence determinations up to but not in excess of the $4 million dollar cap, the Commission holds a hearing, and the Commission has found the 2020 plant additions necessary to support the revenue requirement cap to be prudently incurred, used, and useful. Upon receipt of the request, the Commission will schedule such a hearing. We direct the Company to request an effective date for the step increase no sooner than 30 days from the date the request is filed. We also condition the first step increase on the same conditions included in section 5.4 of the Settlement Agreement, including that it shall be subject to audit and reconciliation based on the results of the audit, as approved by the Commission.

Motion for Protective Order Related to Discovery Responses

RSA Chapter 91-A, ensures public access to information relative to the conduct and activities of government agencies or "public bodies" such as the Commission. Disclosure of records may be required unless the information is protected by statute under RSA 91-A:4 , or exempt from disclosure under RSA 91-A:5. RSA 91-A:5, IV, exempts several categories of information, including personnel practices; confidential, commercial, or financial information; and personnel files. In each instance, the party seeking protection of the information in question has the burden of showing that a privacy interest exists, and that its interest in confidentiality outweighs the public's interest in disclosure. *Union Leader Corp. v. Town of Salem*, 173 N.H. 345, 354-355 (May 29, 2020) (citing *Prof'l Firefighters of N.H. v. Local Gov't Ctr.*, 159 N.H. 699, 707 (2010)). The Commission's rules require a motion for confidential treatment to include, among other things, a "[s]pecific reference to the statutory or common law support for confidentiality" and a "detailed statement of the harm that would result from disclosure." Puc

203.08. The benefits of disclosure to the public are then weighed against the interest(s) in nondisclosure. Separately, RSA 363:37-38 states an independent statutory basis for confidential treatment of individual utility customer data that can identify, singly or in combination, specific customers.

With respect to the requests that are related to confidential information and based solely on RSA 91-A:5, IV's enumerated exemptions, we find that Liberty has identified adequate privacy interests and that disclosure is likely to cause harm to Liberty, its employees, other third parties, and/or customers. Finally, we agree that RSA 363:38 protects the identified customer data and therefore RSA 91-A:4 applies.

Next, we must consider the public interest in disclosure. This information Liberty seeks to protect is unlikely to inform the public of the Commission's regulatory activities. On balance, the public's interest in disclosure of this information is outweighed by the potential harm to Liberty, its employees, third parties, and/or customers. Therefore, we grant Liberty's motions for protective orders filed on July 31, 2020, April 29, 2021, and June 7, 2021. We defer action on Liberty's motion for protective order filed on November 20, 2020 until we issue an order on Liberty's request to recover costs associated with the Granite Bridge project. This ruling is subject to our ongoing authority, on our own motion, or on the motion of Staff, any party, or member of the public to reconsider our determination. *See* Puc 203.08(k).

The Commission reminds the parties that due to recent statutory changes the Commission may not communicate with Department of Energy Staff on pending matters. *See* RSA 12-P:5, VI and, *see generally,* RSA 363:12. As a result, the Commission may lack access to information made available for Department of Energy unless it is directly filed in the Commission's relevant open docket.

Based upon the foregoing, it is hereby

ORDERED, that the Settlement Agreement regarding permanent distribution rates based on the 2019 test year between Liberty, Energy, and the Office of the Consumer Advocate is hereby APPROVED, as set forth and conditioned herein above; and it is

FURTHER ORDERED, that Liberty is hereby authorized to begin recovery of the permanent increase to its distribution revenue requirement of $6,294,290 in rates effective with service rendered on and after August 1, 2021, consistent with the terms of the Settlement Agreement and this order; and it is

FURTHER ORDERED, that temporary rates approved in Order No. 26,412 (September 30, 2020), are to be reconciled with permanent rates approved in this order, with such reconciliation occurring through the Local Distribution Adjustment Clause mechanism over the course of the 12 month period beginning November 1, 2021, consistent with the terms of the Settlement Agreement; and it is

FURTHER ORDERED, that that Liberty is authorized to recover just and reasonable rate case expenses over one year through the Local Distribution Adjustment Clause commencing on November 1, 2021, subject to audit and adjustment, as set forth herein above; and it is

FURTHER ORDERED, that Liberty is authorized to recover two step increases for capital expenditures placed in service in 2020 and 2021 as provided in the Settlement Agreement, subject to further review and determination by the Commission as set forth herein above and in the Settlement Agreement; and it is

FURTHER ORDERED, that Liberty shall file all necessary documentation and reports in support of regulatory costs as noted above, and the step increases, as required by the Settlement Agreement and the conditions of this order; and it is

FURTHER ORDERED, that that the Commission will hold a hearing on Liberty's request for an increase in its step 1 revenue requirement of $4.0 million pursuant to the terms of the Settlement Agreement and conditions of this order; and it is

FURTHER ORDERED, that the Property Tax Adjustment Mechanism described in the Settlement Agreement is APPROVED; and it is

FURTHER ORDERED, that Liberty's Motions for Protective Orders Related to Discovery Responses filed July 31, 2020, April 29, 2021, and June 7, 2021, as discussed in the body of this order, are GRANTED; and it is

FURTHER ORDERED, that Liberty Utilities shall file tariffs conforming to this order within 15 days of the date of this Order pursuant to N.H. Code Admin. R., Puc 1603.02(b).

By order of the Public Utilities Commission of New Hampshire this thirtieth day of July, 2021.

Dianne Martin	Daniel C. Goldner
Chairwoman	Commissioner

Service List - Docket Related

Docket# : 20-105

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EXHIBIT
tabbies
#18
DG 17-048

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 17-048

In the Matter of:
Liberty Utilities (EnergyNorth Natural Gas) Corp., d/b/a Liberty Utilities
Request for Change in Rates

Direct Testimony

of

Al-Azad Iqbal
Utility Analyst – Gas & Water Division

November 30, 2017

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Introduction

Q. Please state your name, occupation and business address.

A. My name is Al-Azad Iqbal, and I am employed by the New Hampshire Public Utilities Commission (Commission) as Utility Analyst. My business address is 21 South Fruit Street, Suite 10, Concord, New Hampshire, 03301.

Q. Please summarize your educational and professional experience.

A. My educational and professional backgrounds are summarized in Appendix A.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide Staff's recommendations on three issues related to the Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities' (Liberty or Company) proposal: 1) on Depreciation Study ; 2) on Decoupling; and, 3) Recovery of Concord Training center.

Q. Please summarize Staff's recommendations on these issues.

A. The depreciation expenses should be adjusted as recommended by Staff and the reserve variance amortization term should be twelve years instead of three years. The decoupling methods proposed by the Company need to be changed in light of the guidance provided by the Commission in relevant dockets and discussed in my testimony. Staff recommends that the Commission deny recovery of training center costs but allow recovery of training costs unrelated to the training center

Depreciation Study

Q. When was the last depreciation study done for EnergyNorth? Is the current study consistent with that last study?

A. EnergyNorth's last depreciation study was done in Docket DG 08-009. In that study, Mr. Normand used the same methodology as presented in this case. In both cases, he used a Simulated Plant Record ("SPR") life analysis approach using a straight line method, broad group procedure, average whole life technique using the "Iowa"-type survivor curves at the account level. Then he evaluated the results using other factors including the character of the depreciable assets, experience, engineering knowledge, and judgment etc. Liberty states that the only difference between the current study and the prior study is that the current study is based on FERC accounts and the prior study was based on PUC accounts.[1]

Q. Please summarize your recommendation on depreciation and amortization expenses.

A. EnergyNorth proposes an overall depreciation and amortization expense of $18,932,544. My recommendation is $15,830,829, a reduction of $3,101,715. Schedule AI-DEP-1 provides a summary of my recommendation. There are two components reflected in my overall recommendation: Depreciation expenses, and the amortization of the depreciation reserve variance. I recommend depreciation expense of $15,001,931 and amortization of depreciation reserve variance of $828,898.

Please refer to Schedule AI-DEP-1 for a summary of my recommendation for depreciation expense. I adjusted the average service life for some accounts based on the outcome of

1 Staff 2-37

statistical analysis done by Mr. Normand.[2] I kept net salvage as proposed by the Company. I agree with Mr. Normand's recommendation to stop the monthly reserve adjustment (Order No. 25,202) and to amortize the reserve variance over two depreciation cycles or 12 years. And thus, my recommendation reflects a 12 year amortization.

Q. Please explain why you adjusted ASL for account 381 and subaccounts.

A. In this study, for the first time for EnergyNorth, different ASL and curves are used at sub-account level. This has created a large impact on depreciation accrual levels as well as reserve variance. In the last study, assets were grouped at the account level (as opposed to the sub-account level in this study). Customer meters and installation were under Account 1360, with an ASL of 35 years (Curve R2.5). In the current study, the assets included under Customer meters and installations are spread across 4 different sub-accounts, each with its own ASL and accrual rate; specifically, accounts for Meters (381), Meter Instruments (381.10), and Meter Installation (382) and Meters-ERTS (381.20). In this study, the first three items (Meters, Meter Instruments and meter Installations) are assigned an ASL 32 and an accrual rate of 3.13%, while Meters – ERTS has an ASL of 15 years and a corresponding accrual rate of 6.7%. This change alone increased the proposed annual accrual amount for the assets in the Meters Group (Account 1360 in the last study) by $150,000. Further, because of this change Meters-ERTS (381.20) now has an average remaining life (ARL) of 2.54 years, compared to the rest of the Meters subaccounts which have an ARL of 18-25 years. This change has a very large impact on Reserve Variance. During its lifespan, accrual rate for Meters ERTS was around 3% (as part of account 381). This rate is much lower than

2 Staff 2-38.b

the proposed 6.7% and this change created a reserve variance of 2.6 million in last 18 years (1997-2015).

Q. What is your recommendation?

A. As indicated Attachment AI-DEP-2, Staff recommends a more gradual approach, which is to use an ASL of 25 years for account 381.20 instead of the 35 years which was recommended for the rest of the 381 sub-accounts. This will help to smooth out the reserve variance. Staff and the Company can revisit this issue and adjust the ASL accordingly in future studies.

Q. What is your recommendation about reserve variance?

A. Staff recommends that the reserve variance be recalculated with staff schedule (AI-DEP-1) and amortized the variance for 12 years, as suggested by Mr. Normand.

Q. Did Liberty incorporate Mr. Normand's recommendation to amortize the reserve variance over 12 years in the revenue requirement proposed in this case?

A. No. The company proposes a 3 year amortization period for the reserve variance. The Company provided no explanation for this in its initial their filing, but did discuss the reasoning in responses to Staff data requests. In response to a Staff data request (Attachment AI-DEP-3), the Company cited generational equity as the reason for the shorter amortization period meaning that a shorter amortization period will help assign the cost of the of the variance to the same customers who took service while the reserve accumulated. But, the company did not provide any analysis which supports their position.

Q. Does the current study support Company's position for a 3 years amortization period?

A. No. the biggest contributor to the reserve variances are Mains and Services. If one looks at the average consumed life and average remaining life, and variance percentages, it is clear that there is no generational inequity in these accounts.

Table 1

Account	Description	Reserve Variance	Average Service Life	Average Consumed Life	Average Remaining Life	Variance (% of plant Balance)
367.00	MAINS	$9,128,041	60	14.08	45.92	4.38%
380.00	SERVICES	$2,169,199	45	13.20	31.80	1.61%

This level of reserve variances in these two accounts is not unexpected considering the high level of recent investment, which can create ups and downs in the reserve. The depreciation rate is set using the straight-line method and theoretical reserve follows an Iowa curve. Depending on what point of its service life the asset is at the time of reserve calculation, and time span between the two depreciation studies, a certain level mismatch is expected. This is one of the reasons depreciation studies are recommended at regular intervals. I agree with Mr. Normand that that stopping the monthly reserve adjustment will reduce the reserve variances in future years.

Decoupling

Q. Has the Commission discussed the issue of decoupling in the past? If so, please summarize these discussions.

A. The Commission conducted an investigation on Energy Efficiency Rate Mechanism in Docket DE 07-064. In that context, decoupling was considered as an alternative. The proceeding was opened to "investigate the merits of instituting…appropriate rate mechanisms, such as revenue decoupling, which would have the effect of removing obstacles to, and encouraging investment in, energy efficiency."[3] In it order in that case, the Commission stated, "energy efficiency rate mechanisms will need to be tailored to the energy efficiency load loss and fixed and variable cost structure of each company." Further, the Commission stated decoupling was considered as a rate design option. "Revenue decoupling could be also be implemented through changes in rate design. That is, the Commission could consider changes to the fixed charge component of the rate design to more accurately align cost causation of the utility's actual fixed costs with the fixed charge component of the rate design." The Commission was mindful about the possible consequences on small rate classes - "any decoupling proposal to change the rate design needs to consider the impact on small rate classes to ensure that such classes are not unduly impacted by such changes." The Commission was also aware of the potential inappropriate risk shifting from decoupling - "revenue decoupling could enhance the utility's revenue stability and reduce earnings volatility; hence, revenue decoupling may result in a shift of risk away from the utility and toward the customer."

3 Order No. 24,934

In Docket DE 15-137, the Commission revisited the issues related to decoupling under the Energy Efficiency Resource Standard. In Order No 25,932, the Commission stated "we are mindful that, with an LRAM, [Lost Revenue Adjustment Mechanism] the utilities' revenues can increase above their authorized revenue requirements from increased sales, and, for that reason and others, some parties prefer decoupling. This is because decoupling provides reconciliations to the last-approved revenue requirement (i.e., in the case of a utility collecting more revenue than its last-approved revenue requirement, the utility would be required to prospectively credit customers for any such over-collection)".

Q. Please briefly describe the Company's decoupling proposal in this matter.

A. The Company proposed a revenue per customer (RPC) decoupling mechanism for all rate classes, with a seasonal adjustment. The RPC for each season will be set in this rate case and then will be used as the starting point to calculate allowed revenues by season. The Actual Revenues per Customer and the RDM revenue shortfall/surplus will be calculated monthly on a calendar month basis. Then, the sum of all the monthly data will be used to calculate actual RPC on a seasonal basis. The difference between the allowed and actual will be adjusted in the next seasonal rates. Here are salient features of the proposal:

- The Company's firm rate classes will be combined into RDM Customer Groups for revenue calculations.
- The RDM adjustment rates will be calculated using the Company's total revenue shortfall or surplus and projected therm deliveries for the upcoming season.

- Expansion rate customers will be excluded from the RDM calculation and not be charged or credited the RDM rate.
- The RDM adjustment will be capped at +/- 5 percent of distribution revenues. Any excess over the 5 percent limit will be deferred for recovery or pass- back in the next period with carrying charges at the prime lending rate.
- A mid-period adjustment will be made if the projected end of the season RDM under or over collection exceeds 10 percent of total projected seasonal distribution revenues.

Q. Please summarize Staff's position.

A. In light of the guidance provided by the Commission in relevant dockets as summarized earlier, Staff believes that the following changes should be included in the decoupling mechanism:

1) The adjustment should be based on weather normalized revenues.
2) The adjustment should be performed at the rate class level (instead of at the company level).
3) Expected revenue should be calculated at individual rate class level, not at combined rate class level.
4) Expansion rate customers should be included in the RDM calculation.
5) The RDM adjustment should be capped at +/- 2 percent.
6) No mid-period adjustment should be made; if needed, an adjustment can be made at the time of Company's next rate case.

Q. Q. Please explain weather normalization of revenue in the context of decoupling (Issue 1 above).

A. The company proposed a full decoupling where the rates will be adjusted based on the difference between total revenue expected (calculated using RPC) and actual revenue realized, that is, without any weather normalization of expected or actual revenues. Under Staff's proposal, the actual revenue realized will be weather normalized and the difference between weather normalized revenue expected and actual weather normalized revenue realized will be used for as a basis for the rate adjustment.

Q. Please explain the reason for this recommendation.

A. As discussed earlier, the Commission decisions discussed decoupling as a mechanism for lessening the impact on utility revenues associated with reductions in sales from increased efficiency and conservation. The Commission was also concerned with the potential for risk shifting via decoupling. The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather etc.) which is well beyond the efficiency and conservation related sales reductions. It also eliminates, all risk except the risk of management inefficiency[4]. Under Liberty's proposal, the RPC is set on weather normalized test year revenue levels. By also weather normalizing the actual revenue realized (as Staff proposes), the risk of colder or warmer temperatures will stay with the Company. The

4 Testimony of Gregg H. Therrien, Bates 289-90 "The utility remains at risk for managing its expenses commensurate with the level set for the test year base rates. This means the utility must manage its capital expenditure programs, its operations (e.g., salaries and wages, benefits, overtime, maintenance programs, uncollectible, outside services, etc.), and pay taxes (including property taxes that are adjusted annually by most municipalities)".

decoupling adjustment will compensate the utility for the revenues that it would have collected had sales-impacting events including energy efficiency and ups and downs in the economy. Staff's position in this case is consistent with Staff testimony in the EERS docket[5]and aligns more closely to the guidance provided by the Commission concerning decoupling.

Q. Did Liberty discuss the concept of a weather normalized true up calculation?

A. Yes. Mr. Therrien stated - "The true up calculation could be performed by determining the difference between target revenues and weather normalized actual revenues. Using this approach, the revenue true-up calculation would not be affected by colder or warmer than normal weather."[6] He stated that this method would involve "a complicated normalization calculation and subsequent Commission review" and discarded the idea on that basis. However, given that in most gas company filings in New Hampshire (for example, rate cases, cost of gas, etc.) weather normalization is standard practice, this concern is not valid.

Q. Please explain the reasons for combining the rate classes in groups for purposes of calculating a decoupling adjustment (Issues 2 and 3 above).

A. Mr. Therrien cited two reasons – 1) the potential shifting of C&I customers between rate classes causing unintended results in the RDM calculations, and 2) significant year-to-year variability in normal revenue per customer for several C&I rate classes. He concluded that RDM rate adjustments for each C&I rate class would likely result in noticeable rate volatility for some C&I rate classes and

5 DE 15-137, Staff Testimony at 7 "In order to compensate the utilities for lost revenues associated with energy efficiency, Staff recommends the adoption of a lost revenue recovery mechanism for an initial three-year period, to be replaced by a decoupling mechanism in the future".
6 Testimony of Gregg H. Therrien, Bates 294

that this potential volatility is avoided with a single RDM true-up calculation for all C&I rate classes combined.

Q. Do you agree with this observation?

A. I agree that RDM rate adjustments for each C&I rate class would likely result in noticeable rate volatility for some C&I rate classes which could be avoided with a single RDM true-up calculation for all C&I rate classes combined. I disagree that expected revenue should be calculated at the group level.

Q. Please explain.

A. There are two parts of revenue adjustments – one is the calculation of expected revenue, and the other is how to distribute the difference between actual and expected revenue. Accuracy on both fronts is important. The C&I customers are not homogenous in their usage and corresponding RPCs. For example, the annual RPC of a G-41 customer is $1,285 and for a G-54 customer is $40,000. When the C&I classes are combined, RPC is only $2,533. So, if a G-54 customer is added or leaves the system, the expected revenue will change only $2,533 instead of $40,000. So the Company, or the rest of the C&I customers, have to account for the difference of $37,500. By calculating expected revenue at the rate class level, this inaccuracy is eliminated. After calculating expected revenue for each class, one can sum those up to arrive at the expected total C&I revenue. Once we know the difference between expected revenue (as calculated for all the C&I classes) and actual revenue at for all C&I classes combined, we can allocate the difference on a per therm basis for the combined C&I classes. This way we calculate the expected revenue accurately and address the volatility issue too. This method will also accurately catch any impact of inter-class migration, whereas the

Company's proposed method is indifferent to inter-class migration.

Q. Do you agree that the decoupling adjustment to rates should be at the Company level?

A. No. The whole reason for revenue decoupling stems from energy efficiency program. Unlike electric utility's System Benefits charge (SBC), gas utilities have a different mechanism to budget and recover the cost of energy efficiency program. Due to class specific the program design, cost recovery is generally different for residential and C&I sectors. In the past years, there have been significant differences in gas energy efficiency ("EE") programs between the sectors. The two sectors have significantly different EE charges per therm in the LDAC. Energy savings and corresponding lost revenue would differ by sector as well. Currently, for the same reason, LRAM is calculated at sector level. Thus, Staff believes that any decoupling adjustment should be done at the sector level, consistent with the planning, budgeting and implementation of the gas EE programs.

Q. Please explain how expansion rate (MEP) customers should be treated for decoupling (Issue 4 above).

A. The Company proposed to exclude the MEP customer in the decoupling adjustment rate calculation. Staff believes these customers should be included in determining RPC and when calculating the rate adjustments. It is important that their usage should be counted in its original rate class. Staff believes RPC for MEP customer should be included in the rate class revenue calculation after the MEP premium is separated. MEP premium is a known percentage added to the various class delivery rates, so it is simple to separate and remove the premium for purposes of calculating a decoupling adjustment.

Q. Please explain why you are proposing 2% cap instead of 5% cap as proposed by the

Company and elimination of the midyear adjustment (Issues 5 and 6 above).

A. By weather normalizing the actual revenue for the purpose of the decoupling adjustment, one of the biggest reasons for revenue fluctuation (the weather) is removed. Nationwide experience has shown that annual adjustments are typically in the range of -2% (a refund) to +2% (a surcharge), when weather is removed. So Staff believes that a 2% cap is reasonable. For the same reason, Staff believes that there will be no need for mid-term adjustment (Issue 6 above). If needed, the adjustment could be done in the Company's next rate case.

Q. Do you have any other comments or recommendations??

A. Staff believes that any decoupling related adjustment should be tied to the Company's energy efficiency program performance. If the Company does not meet its EE goals, there should be some restriction in decoupling adjustment because the logical conclusion is that the decoupling adjustment was attributed to something other than EE. In the event that a decoupling adjustment is calculated in any year where Liberty does not meet its EE goals as established in the docket where EE programs are approved, Staff recommends that the Company be required to demonstrate that its EE efforts were the primary factor in reducing its energy sales in order for any amount above the decoupling cap to be carried forward for recovery in a subsequent year. This would not apply on any refund, because that would occur in a year where revenues are growing, and thus on its face it is clear that the decoupling adjustment is not attributable to EE efforts.

Rate Design Issues

Q. Please explain why a rate design change is needed if a decoupling adjustment is approved in this case?

A. In the context of decoupling and the associated policy goal of energy conservation, Liberty's the current rate design is incompatible. For example, currently, there are two rate blocks - head block and tail block. The rate is higher for the head block to provide the utility a reasonable opportunity to collect fixed costs which are not recovered through the customer charge. The idea is that most of the customers' usage will fall in the head block and thus the fixed costs will be recovered. However, from an energy efficiency perspective, this gives the wrong signal to the consumers as they pay less on per unit basis for higher energy use. Under decoupling, the Company has a much greater assurance of collecting its fixed costs and that opens the door to address the "anti-conservation" price signal of declining rate blocks.

Q. Please describe your recommendation regarding rate design in the context of decoupling.

A. Staff believes that the decoupling provides an opportunity to change rate design without harming the Company and at the same time, further the goal of energy conservation. In this context, Staff proposes the following changes:

1. Set the rates for both head and tail block at the same level
2. Any decoupling adjustment would be allocated to the head or tail blocks based on whether it is a surcharge or refund. Refunds will be allocated to head block and surcharges will be collected from the tail block for the residential sector and high winter use C&I customers.

Q. Please explain why you recommend setting both head and tail block rate at the same level.

A. The only reason the head block rates are set higher than the tail block is to allow the Company to recover its customer related fixed cost from the customers whose customer charge is set below the level need to recover these fixed costs. In absence of decoupling, Staff is supportive of gradual increases in the customer charge to approach recovery of the fixed costs. As discussed earlier, with decoupling, Staff believes that there is no longer a need for higher head block rates. But, Staff is not recommending elimination of the two blocks, just that the rates be set at the same level, before any decoupling adjustment is made.

Q. Why is it reasonable to allocate decoupling refunds to the head block and surcharges to the tail block?

A. There are several reasons it is compatible with energy conservation policy. First of all, over time, this will create the same dynamic as an inclining rate block structure, which is a known tool in the context of energy conservation. It will provide a proper price signal to the customers to encourage energy conservation. This approach would also benefit lower consumption households that could tend to include be lower income households with smaller homes and less energy use compared to higher income households. Low use households, on average, have relatively little or no consumption in the tail block and thus would see little or no rate increases from decoupling. This addresses the stated concern of the Commission that "any decoupling proposal to change the rate design needs to consider the impact on small rate classes to ensure that such classes are not unduly impacted by such changes"[7]. It also reduces the volatility of gas bills for low use customers.

7 Order No. 24,934 (January 16, 2009)

Concord Training Center

Q. What is the purpose of your testimony about Concord Training center?

A. The purpose of my testimony is to provide Staff's recommendation as to whether the costs associated with the Liberty's Concord Training Center costs should be recovered through the rates proposed in this proceeding. Last year, in Docket 16-383 involving the Company's electric affiliate, Granite State Electric Company, Staff addressed this same issue and recommended further investigation. Staff cited a lack of reliable analysis and support in the decision-making process and questioned whether the construction of the training center was a prudent investment for Liberty compared to other alternatives available for training. A copy of my testimony and schedules from Docket 16-383 is provided as Attachment AI-TR1. In this docket, Staff has completed its review of the training center and recommends that the Commission disallow recovery of all training center related cost from rates.

Q. Did you review Company's Business Cases during this proceeding?

A. Yes. The Company provided two Business Cases related to the Concord Training Center. The first business case, dated January 24, 2014 (Attachment AI-TR 2) provided a brief description of the training center and mentioned training at National Grid's facility in Millbury, MA as an alternative to an estimated cost of training $400,000/year. Under the Financial Assessment section, the Business Case stated a payback period of fewer than 3 years for the investment in the training center. The second business case, dated May 1, 2014, had fewer details and contained no analysis of alternative options and no financial assessments. None of the documents, indicated that the Company made any consideration of the operating and maintenance expenses Liberty would incur for the training center, in addition to training costs.

Q. Did the Company provide any support for its alternatives and financial assessment in its business cases?

A. Several times, Staff requested that Liberty provide any financial analysis supporting Liberty's decision to build the training center, but no reasonably adequate analysis was provided. In data response Staff 2-3 from DE 16-560 (provided as Attachment AI-TR 3) , the Company did perform a cost-benefit analysis, for the first time, between a training center and training at a National Grid facility in Millbury, MA, which was the alternative cited in their initial business case. When Staff raised questions about the usefulness of the analysis (Staff Testimony DE 16-383 at bates 000010-11, Attachment AI-TR1), the Company responded that the analysis has "little relevance to the decision to build the training center"[8] and the analysis is "pointless" because training at the National Grid facility was no longer an option.

Q. Did the Company consider any other alternatives to building its own training center?

A. According to the business cases, no other alternatives were considered. Later, the Company argued that only alternative it had was to build a training center due to the absence of National Grid facilities. "If training center had not been constructed, Liberty would have been without any viable option for training employees."[9]

Q. Did the Company provide any support for its conclusion that building its own training center was the only option available?

A. No. To the contrary, when asked about organizations Liberty reached out to explore possible alternatives to the National Grid's training arrangement, the Company stated "Company

8 Rebuttal Testimony of Smith and Mullen DE 16-383 at 227-229
9 Ibid at page 227-228

personnel contacted management employees at Unitil Energy Systems (UES), New Hampshire Electric Cooperative (NHEC), and Green Mountain Power (GMP) and discussed their current training methods. UES and NHEC train on the job with the training conducted by supervisors rather than dedicated trainers. GMP has a dedicated trainer who performs classroom and field based training"[10]. Liberty also reached out to Eversource, which had a training facility in Pittsfield, which has subsequently closed. This demonstrates that Liberty knew that other New Hampshire utilities performed training without a dedicated building and without dedicated trainers, yet Liberty did not consider or analyze any of these alternative training models or methods as an alternative to building its training center. Instead, Liberty determined that those methods were not viable alternatives for providing the range of gas and electric training needs required by Liberty, and therefore it concluded that no financial/economic analysis of those options was warranted.[11]

Q. Why, according to Liberty, were alternative methods of training not viable?

A. Liberty simply states that on the job training is "insufficient" to ensure employees to "fully learn" and safely perform their function. [12] When asked to provide analyses, rules/standards, studies etc. supporting this conclusion, the Company provided none and stated that "it is the Company's view that "exclusive" reliance on that [on the job] training method would not provide the optimal training experience". [13]

Q. Did the Company attempt to obtain training services from an outside provider?

A. No. The Company stated that "although Liberty did not issue RFPs, Liberty did reach out to

10 Staff 4-24
11 Staff 5-43
12 DE 16-383, at Smith/Mullen Rebuttal Testimony, 229-230;
13 Staff 5-40

other regional utilities to explore training alternatives." [14] Staff believes that a simple and appropriate way to explore the market for any services is to issue an RFP and that Liberty should have issued an RFP for its training needs prior to undertaking the construction of the dedicated training center.

Q. Has Liberty mentioned other benefits of a dedicated training center?

A. The Company cites flexibility of scheduling, the ability to train non-field employees on gas and electric utility topics, and the ability to make the facility available at times to accommodate training-related events including use of the facility by outside parties as other benefits[15].

Q. Did the Company provide any analysis of those benefits?

A. No, when asked for financial/economic analysis of any efficiency gains, Liberty rehashed reasons already stated and concluded that: "Even without any financial analysis, it is clear that each of those training conditions offers efficiencies in terms of consistency of training, scheduling, planning, travel time, and controlled training conditions, among other things".[16] The Company further explained "a financial/economic analysis was not performed as attempting to quantify the gains would have involved complex analyses of a number of variable factors including travel distances, number of employees who could be trained at each job location, ability of supervisors to take time from other job tasks to perform training, variability in training among supervisors, potential follow-up training due to that variability, ability to train specific tasks due to job site conditions, ability of training personnel to

14 Staff 5-42
15 Testimony of Mr..Mullen, filed on June 30, 2017 at page 023-027
16 Staff 4-26

effectively schedule training at numerous locations, etc. Thus, the results of any financial/economic analysis would be highly variable, subject to a range of challenges, and thus of questionable value."[17]

In another data response Company stated "While some of those items may involve quantifiable benefits, the majority involve non-quantifiable benefits. Hence, there is no analysis responsive to this request"[18].

Further, Staff asked about the policy or guideline etc. related to using non-quantifiable costs or benefits in its decision making. Liberty referred to the Business case[19], section on Risk assessment and Qualitative Evaluation. Staff could not find any mention of non-quantifiable costs or benefits in either of the business cases concerning the training center.

Q. In your view, should Liberty have attempted to perform more in depth analyses of the perceived benefits of building a stand-alone training center?

A. Yes. Every decision involves dealing with different future scenarios and options. A rational decision maker would use reasonable assumptions to assess those scenarios and options instead of discarding them outright. That is particularly true in this instance, where the perceived benefits (efficiency, scheduling, improved quality of training etc.) form the basis of the decision to build the training center, not analyzing these factors is not acceptable. The fact that performing analyses is difficult and complex, and that such analyses could face

17 ibid. (Staff 4-26.)
18 Staff 4-32
19 Staff 5-45

challenges should not be used as a rationale for not doing any analyses.

The most basic analysis Liberty could have done is to compare its expiring option (training at National Grid) and their preferred option (dedicated training center) to address the variability in cost of these two alternatives. Had the Company done a thorough analysis of these two alternatives and reviewed the analysis as a sanity test (as was done by Staff in DA 16-560, Staff 2-3 – attached here as Attachment AI-TR 3), Liberty's ultimate decision to build a training center may have been different[20].

Q. Why is that?

A. Going back to the first business case, the Company would have known that the $400,000/training cost (the National Grid option) [21] would not automatically translate to a fewer than three year payback period for a $1,000,000 plus investment. Such an analysis would have revealed that most of Liberty's historic training costs (particularly the payroll cost of the trainees), would remain irrespective of what alternatives Liberty choose. The analysis would have revealed that Liberty should have been evaluating options based only on the incremental cost or savings of the options and Liberty should ignore trainee payroll costs that would remain under any option. Staff believes this would have provided tremendous value in the context of the training center decision making.

Q. Did the Company analyze the incremental cost related to Training center?

A. As best as Staff can determine, the Company did not analyze incremental costs. These incremental costs would include: costs for the trainers, operation and maintenance cost,

20 Staff Testimony in DE 16-383 (attached here at Attachment AI-TR 1) discussed that analysis in detail.
21 Staff was told in 2014 that Liberty historic annual training costs approximated $400,000. (DG 14-180, Staff 2-6, response, 2014 costs of $448,210; DG 14-180, Staff 2-107, costs of $413,250 for the test year and $341,040 from April 2014 through March 2015),

property tax, return on the investment, etc. These costs could have been estimated reliably and should have been part of any financial analysis, had the Company undertaken any financial analyses in its decision-making process.

Q. Did the company perform any financial analysis in the face of increasing cost of its selected option – the dedicated training center?

A. No. although the Company states that "Cost increases were reviewed, analyzed, and approved as they arose"[22], it did not perform any financial analysis, even in the case of three fold increase of the cost[23] .

Q. Did you looked at the training cost trend pre and post training center for Energy North?

A. Yes, in my testimony in DE 16-383: Table 5 - Annual Training Cost, I provided an analysis of EnergyNorth's training costs, expressed on a $ per hour of training basis. Below is an updated version of the analysis.

Table 2 Energy North Training Costs

	Training Cost	Training Center Cost[24]	Total	Hours	Training Cost/Hour	Training Cost/Hour (without training center cost)
2013	$288,163	$0	$288,163	3,233	$89	$89
2014	$325,724	$0	$325,724	3,918	$83	$83
2015	$305,302	$439,678	$744,980	3,446	$216	$89
2016	$237,084	$384,411	$621,495	2,756	$226	$86

22 Staff 5-44
23 Staff 7-12
24 Staff 2-26

This illustrates that the average hourly training cost did not change much over time, when the training center costs were excluded. It also supports our earlier assertion that a financial analysis based on incremental training costs would have made clear to the decision makers that the proposed project would not generate sufficient savings to pay for itself in less than three years. And it shows that Liberty's decision to build a dedicated, stand-alone training center actually harmed its ratepayers by significantly increasing the average training cost/hour.

Q. Please summarize your findings?

A. Staff investigation is summarized here:

- Business cases were used as the basis for the decision by the management to build the training center, but the business cases are not supported by any detailed financial analysis:
  - the financial assessment used was erroneous or inadequate and without support
  - no qualitative evaluation was done
  - no analysis of incremental costs was performed.
- None of the alternative methods to train employees were explored to any significant degree:
  - Liberty was aware of the alternative methods used for training by other utilities
  - Liberty's rationale for not exploring alternatives is not supported by any data, standard, rule, study or report
  - Liberty did not explore training alternatives by issuing an RFP to training service providers.

- Liberty disregarded any need for financial analysis at every step of its decision making (except when asked by Staff).

The absence of any credible analysis of its chosen path to build a training center and its failure to analyze available viable alternatives based on unsupported conclusion raise serious concerns about Liberty's decision to build the training center and its decision making process. Credible analyses would have provided the decision makers the information (that was known or should have been known at the time of the decision) that should have led to a decision not to build a training center (at least not with significantly more study of the costs of the center and any alternatives).

Q. What is your recommendation?

A. It is clear that Liberty did not perform any credible analysis in the process of the deciding to build the Training center, and consequently harming its ratepayer with increased cost. Staff believes the Company failed to meet any standard applicable to any reasonable decision-making process involving a substantial investment. Staff recommends that the commission deny recovery of training center costs bur allow recovery of training costs unrelated to the training center.

Q. Does that conclude your testimony?

A. Yes.

Attachments

Appendix A

Educational and Professional Background
Al-Azad Iqbal

I am employed by the New Hampshire Public Utilities Commission (PUC) as a Utility Analyst. My business address is 21 S. Fruit Street, Suite 10, Concord New Hampshire, 03301.

I received my Bachelor degree in Architecture (B. Arch) from Bangladesh University of Engineering and Technology. Later, I received my Masters (MS) in Environmental Management from Asian Institute of Technology and another Masters in City and Regional Planning (MCRP) from the Ohio State University. I was a Doctoral Candidate at the City and Regional Planning Department at the Ohio State University. After joining the PUC in 2007, I participated in several utility related training courses including Marginal cost training by NERA, Advanced Regulatory Studies at Institute of Public Utilities, Michigan State University, Depreciation Training by Society of Depreciation Professionals.

Prior to joining the PUC, I was involved in teaching and research activities in different academic and research organizations. Most of my research work was related to quantitative analysis of regional and environmental issues.

Attachment AI-DEP-1

Depreciation and Amortization Adjustments

Depreciation and Amortization	Proposed	Staff Recommendation	Difference
Depreciation Expenses[25]	$15,616,951	$15,001,931	($615,020)
Amortization of Reserve Variance[26]	$3,315,593	$828,898	($2,486,695)
Total	$18,932,544	$15,830,829	($3,101,715)

25 Based on updated number included in revenue requirement testimony of Laflamme and Mullinax (Adjustment 14), attachment Schedule 3.14 and 3.14 Depr WP
26 This amount will change with updated reserve variance as suggested in the testimony.

Attachment AI-DEP-2[27]
Staff recommendation of Depreciation

FERC			Proposed				Staff Proposal				Difference Between
ACCOUNT NUMBER	Description	Plant balance	ASL	NET SALVAGE %	ANNUAL ACCRUAL RATES	DEPREC. ACCRUAL	ASL	NET SALVAGE %	ANNUAL ACCRUAL RATES	DEPREC. ACCRUAL	
303.00	Capitalized Software	14,745,889	6.2	0	16.13	2,378,512	7	0	14.29	2,106,556	-271,956
	Production Plant										
305.00	Structures And Improvements	1,975,163	35.0	0	2.86	56,490	35	0	2.86	56,433	-56
311.00	Lp Gas Equipment	258,481	35.0	0	2.86	7,393	35	0	2.86	7,385	-7
320.00	Other Equipment-Lng	2,556,209	35.0	0	2.86	73,108	35	0	2.86	73,035	-73
320.10	Other Equipment-Production	8,777,306	35.0	0	2.86	251,031	35	0	2.86	250,780	-251
	Total Deprec. Production Plant	13,567,159	35.0		2.86	388,021				387,633	-388
	Storage Plant										
361.00	Structures And Improvements-Lng	57,345	35.0	0	2.86	1,640	35	0	2.86	1,638	-2
363.50	Other Equipment-Lng	7,646	35.0	0	2.86	219	35	0	2.86	218	0

27 It is based on original Depreciation Schedule A. Updated numbers with same accrual rates are included in revenue requirement testimony of Laflamme and Mullinax.

	Total Deprec. Storage Plant	64,991	35.0		2.86	1,859	35			1,857	-2
	Transmission Plant										
366.20	Structures And Improvements	269,809	35.0	0	2.86	7,717	35	0	2.86	7,709	-8
366.30	Structures And Improvements-Other	353,851	35.0	0	2.86	10,120	35	0	2.86	10,110	-10
367.00	Mains	234,672,697	60.0	-15	1.92	4,505,716	60	-15	1.92	4,497,893	-7,822
369.00	Measuring And Regulating Station Equip.	4,909,208	35.0	0	2.86	140,403	35	0	2.86	140,263	-140
	Total Deprec. Transmission Plant	240,205,565	59.0		1.94	4,663,956				4,655,975	-7,980
	Distribution Plant										
380.00	Services	146,720,226	45.0	-60	3.55	5,208,568	45	-60	3.56	5,216,719	8,151
381.00	Meters	14,628,345	32.0	0	3.13	457,867	**35**	0	**2.86**	417,953	-39,914
381.10	Meters-Instrument	188,398	32.0	0	3.13	5,897	**35**	0	**2.86**	5,383	-514
381.20	Meters-Erts	5,647,769	32.0	0	6.67	376,706	**25**	0	**4.00**	225,911	-150,795
382.00	Meter Installations	14,360,005	32.0	0	3.13	449,468	**35**	0	**2.86**	410,286	-39,182
387.00	Other Equipment	908,013	19.0	0	5.26	47,761	19	0	5.26	47,790	29
	Total Deprec. Distribution Plant	182,452,756	41.5		3.59	6,546,268	42			6,324,041	-222,226
	General Plant										
390.00	Structures And Improvements	22,070,702	35.0	0	2.86	631,222	35	0	2.86	630,591	-631

391.00	Office Furniture And Equip.	285,566	18.0	5	5.28	15,078	18	5	5.28	15,072	-6
391.10	Office Furniture And Equip.-Computers	1,840,911	10.0	0	10.00	184,091	**11**	0	**9.09**	167,356	-16,736
391.20	Office Furniture And Equip.-Laptop Comp.	679,916	5.0	0	20.00	135,983	5	0	20.00	135,983	0
393.00	Stores Equipment	99,421	30.0	0	3.33	3,311	30	0	3.33	3,314	3
394.00	Tools, Shop & Garage Equipment	825,963	19.0	0	5.26	43,446	19	0	5.26	43,472	26
394.10	Tools, Shop & Garage Equipment-Cng Station	221,199	19.0	0	5.26	11,635	19	0	5.26	11,642	7
397.00	Communication Equipment	443,965	10.0	0	10.00	44,397	**15**	0	6.67	29,598	-14,799
398.00	Miscellaneous General Equipment	348,302	15.0	0	6.67	23,232	**12**	0	8.33	29,025	5,793
	Total Deprec. General Plant	26,815,945	24.5		4.07	1,092,394	25			1,066,052	-26,342
	Total Deprec. Gas Plant	477,852,305				15,071,009				14,542,115	-528,894

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests – Technical Session Set 1

Date Request Received: 8/29/17
Request No. Staff Tech 1-45

Date of Response: 9/13/17
Respondent: Steven Mullen

REQUEST:

Reference Staff 5-48. Mr. Normand discusses the recommendation that the depreciation reserve variance be amortized over 12 years. On Schedule RR-EN-3-6 (Bates 052), the Company proposes to amortize the variance over 3 years. In the technical session Liberty referred to additional considerations outside of the depreciation study that gave rise to the 3 year amortization proposal. Please describe these considerations in more detail.

RESPONSE:

There are many considerations that must be taken into account when any amount is either to be recovered from customers or flowed back to customers over a period of years. Those considerations include such things as: the length of time over which the amount accumulated, the total duration of time from the first creation of the item until its planned disposition using the proposed amortization period, the magnitude of the amount, inter-generational equity issues, and the expected period of time between rate cases.

In this case, we are dealing with an approximate $10 million depreciation reserve deficit that started as a $12.4 million depreciation reserve surplus in an earlier rate case docket, DG 08-009. Per agreement among the settling parties in that docket, that surplus has been flowed back to customers at an annual rate of $933,588 since July 1, 2009. That agreed amortization period was a little over 13 years. However, seven-and-a-half years later (i.e., through December 31, 2016), the reserve variance is now a deficit of approximately $10 million, meaning that the Company has under-recorded depreciation expense for a number of years, with a significant portion due to the amount that has annually been flowed back to customers (approximately $7 million). Although the depreciation reserve surplus of $12.4 million was an agreed upon amount in DG 08-009, it is clear that a significant correction is now needed. Since the current depreciation reserve deficit has been incurred over seven-and-a-half years, extending the period of time by another 12 years to address the existing imbalance would lead to a situation where significant inter-generational equity issues would exist for an extended period of time rather than being addressed in the near future. Although inter-generational equity issues are inherent in ratemaking, an extended amortization period would exacerbate those issues. Assuming a three-year rate case cycle, the Company's proposed amortization period would address the current reserve imbalance by the time of the next rate case and the Company would consider performing an updated comparison of the theoretical-versus-actual depreciation reserves at that time without the necessity and expense of filing a new depreciation study. Revisiting the status of the depreciation reserves in that relatively short period of time would help avoid the accumulation of a large reserve imbalance, either a surplus or a deficit, which could otherwise accumulate over an extended amortization period.

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DE 16-383

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

Request for Change in Rates

DIRECT TESTIMONY OF

AL-AZAD IQBAL

December 16, 2016

Q. Please state your name, current position, and business address.

A. My name is Al-Azad Iqbal, and I am employed by the New Hampshire Public Utilities Commission (Commission) as Utility Analyst. My business address is 21 South Fruit Street, Suite 10, Concord, New Hampshire, 03301.

Q. Please summarize your educational and professional background.

A. My educational and professional backgrounds are summarized in Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's recommendation as to whether the costs associated with the Company's Concord Training Center costs should be recovered through the rates proposed in this proceeding. This recommendation impacts a larger question concerning whether the construction of the Training Center was a prudent investment for Liberty as a whole (Granite State Electric and EnergyNorth) as compared to other alternatives available for training. In addition to providing information on Training Center costs, cost allocation, cost recovery and utilization, my testimony also examines the methodology and underlying assumptions used by Liberty to evaluate the cost and benefits of building the Training Center.

Q. Please summarize your finding and recommendations regarding on these issues.

A. The Commission should deny recovery of the Training Center costs in this proceeding and address the issue of cost recovery in the next Liberty Utilities (EnergyNorth Natural Gas) Corp., d/b/a Liberty Utilities ("EnergyNorth") rate filing, where a full prudence review can be conducted. In this proceeding (and in Docket DA 16- 560 where Liberty has requested approval of the lease of the facility by EnergyNorth to Granite State as an transaction between a utility and an affiliated party), Liberty failed to provide a cost/benefit analysis on which the decision to build, maintain and operate a training center justified the decision to go forward with the project. Furthermore, the information provided in this case and the Affiliate Transaction docket does not demonstrate that building the Training Center was the least cost alternative. Finally, in the event that the Commission includes the costs associated with the Training Center in rates, Staff recommends that the Training Center costs be allocated between the gas and electric utilities based on actual training hours, rather than number of employees as is currently being done.

Q. Briefly describe Liberty's filings that address the Training Center.

A. In DG 14-180, EnergyNorth's last rate filing, Liberty identified the Training Center as a future capital investment that it would be seeking to recover in rates after it was placed into service.

In DA 16-560, Liberty provided a lease agreement between EnergyNorth and Granite State whereby Granite State is leasing the non-exclusive right to occupy and use the land and building known as the Training Center. The lease provides that "Granite State's Proportionate Share" shall be twenty-five percent (25%) and will be recalculated based on the ratio of EnergyNorth's and Granite State's union employees as of end of the immediately preceding calendar year.

In DE 16-383, this Granite State rate case, Granite State seeks to recover $146,559 (Schedule RR-3-12(CU)) of lease costs for the Training Center.

In none of these dockets has Liberty provided sufficient support to demonstrate the reasonableness of building the Training Center.

Q. Please summarize the Training Center capital costs and annual operating expenses.

A. See Table 1, below, for the original projected cost, actual cost, operating and maintenance costs.

Table 1: Concord Training Center Estimated Annual Operating Costs[1]

Original Estimated Cost [2]	1,450,000
Cost of building on books	4,109,880
Accum Depr thru 3/31/16	(118,365)
	3,991,515
Return @ EnergyNorth WACC of 7.05%	281,402
Annual Book Depreciation	118,364
Estimated Insurance on Bldg.	1,500
Utilities	39,762
Property Taxes	30,210
Routine Maintenance	115,000
Total	586,238
Percentage to GSE based on use @ 25%	146,559

Q. Please briefly describe Liberty's supporting analysis.

A. In response to data request Staff 2-3 in DA 16-560, Granite State provided a cost/benefit analysis and its rationale for building the Training Center. Granite State examined only the incremental cost of training personnel at the National Grid training facility at Millbury, Massachusetts based on six months of training use by gas employees and 12 months of training by electric employees during 2013. Basically, these incremental costs involved travel costs and overtime for attendees and, where appropriate, cost of instructors. Liberty referenced some minor benefits (scheduling efficiency, optional basic training for non-field employees, training for other stakeholders, etc.) associated with building the Training Center but did not provide any

[1] Attachment AI-1 (DA 16-560 Staff 1-2)
[2] Attachment AI-2 (DG 14-180, Brouillard testimony, Bates page 0175)

cost or savings estimates for those items. In response to data request Staff 1-1 in DA 16-560, Granite State stated that it included training hours projected in 2016 as its rational for the 25% allocation of costs to Granite State.

Regarding alternatives for training sources, Liberty mentioned that it searched the local area for another source of training and found no available gas or electric training. It also considered utilizing an existing Liberty facility in the Manchester yard but ruled it out because of environmental and permitting issues.

Q. What is your opinion of the analysis provided?

A. Staff believes that the analysis is inadequate, especially considering that the Training Center was budgeted to cost $1.5 million, and, ultimately, cost over $4 million. First, Granite State analyzed only one year's incremental cost of training at the National Grid facility at Millbury, MA. The Company provided no evidence that during its decision making process it evaluated the cost of training options other than using existing Liberty facilities (such as the Manchester yard) or the cost of building a new training center. A comparative economic analysis of training options should have been done at or before the time when the decision was made to build and operate the Training Center. Based on the information provided by the Company in its filings and through discovery, it appears the decision to build the Training Center was not a prudent decision, as it has resulted in a significant increase in annual training costs. A more thorough analysis prior to making that decision most likely would have resulted in a different outcome, one that would have been less costly, therefore, the costs associated with the Training Center should not be allowed in rates in this proceeding.

Q. Please elaborate on your concerns about Liberty's analysis?

A. Staff has concerns about the accuracy and usefulness of Liberty's incremental cost analysis. As mentioned earlier, using only one year's cost for analysis to analyze an investment of $4 million is far too simplistic. Staff believes that a long term economic analysis (i.e. discounted cash flow analysis etc.) should have been done for this project.

Liberty calculated an annual incremental cost $374,490 (combined Granite State and EnergyNorth) of using National Grid for training. Incremental costs included travel time, overtime where applicable and instructor costs, all of which could be avoided or reduced if training were done locally.[3] The estimated cost savings are significantly less than the combined Granite State and EnergyNorth annual cost of $586,238 (revenue requirement to recover the capital cost and operating and maintenance expenses) for the Training Center.[4] This limited analysis indicates that building the Training Center increased combined company annual training costs by $211,748.

Furthermore, Staff has concerns about the hours and costs Liberty used to calculate the incremental cost of training using National Grid. The incremental cost is based on an analysis of employees who trained at National Grid during periods of time in 2013. According to Liberty, the incremental travel time was approximately 3,000 hours (combined Granite State and EnergyNorth for both Management and Union trainees for the year 2013. (DA 16-650 Staff 2-3). Staff compared these estimated hours with 2013 actual training data (Staff Tech 1-3[5]), which shows total actual hours of 3,699 for all Management and Union related training hours, including travel. If the estimated incremental hours (travel to Milford MA) is correct, only 699 hours were for actual

[3] Attachment AI-3 (Staff 2-3, in DA 16-560)
[4] Attachment AI-1 (DA 16-560 Staff 1-2)
5Staff questioned the accuracy of the data in Staff 2-3 at a technicalthe technical session which prompted Liberty to update the response in Staff Tech 1-3.

training. Liberty also stated that the incremental cost figure was derived from a conservative estimate.[6] These figures raise concerns regarding the accuracy of Liberty's incremental cost estimates and its justification for the Training Center.

A comparison of actual Management and Union related training cost and incremental cost for 2013 shows a similar anomaly. See Table-2 and Table-3, below. The total payroll cost for actual training was $194,811 whereas Liberty's estimated incremental cost saving is $157,770. Inexplicably, for Granite State the estimated hours saved are higher than the actuals (1,692 hours of estimated travel savings versus 1,008 hours of total actual training). Liberty mentioned (Tech 1-3) that the actual costs do not include National Grid instructor costs because Liberty was not billed for these costs. No analysis has been provided comparing the cost for a National Grid instructor(s) with the cost of the Liberty instructor(s), so it is undetermined as to whether instructor training would differ.

Table 2: 2013 Actual Training Hours (Source: Staff Tech 1-3[7])

	Energy North		Granite State		
	No. Of trainee	Hours	No. Of trainee	Hours	Total Hours
Management:	7	168	14	336	504
Union:	87	2523	24	672	3195
Total		2691		1008	3699
Payroll		$126,037		$68,774	$194,811

[6] Attachment AI-3 (DG 16-560, Staff 2-3) "As the cost estimate was based on the number of employees who attended training during that time period, the cost estimate is significantly less than the amount that would be calculated based on the amount of training that has been conducted and will be conducted going forward at the Liberty training center…"
[7] Attachment AI-4

Table 3: 2013 Incremental Hours (Source: DA 16-560, Staff 2-3[8])

	Energy North		Granite State		Total
	No. Of trainee	Hours	No. Of trainee	Hours	
Management:	1	80	16	288	368
Union:	15	1200	52	1404	2604
Total		1280		1692	2972
Overtime Payroll		$63,000		$94,770	$157,770

Staff also compared 2015 training costs, the first year the Training Center was used, with previous years' training costs to see if any savings were achieved, but Staff could not identify any savings.

Table 4: Yearly Management and Union Training cost – actual per Staff Tech 1-3[9]

	Energy North		Granite State	
Year	No. of trainee	Cost	No. of trainee	Cost
2013	94	$249,656	38	$237,994
2014	101	$305,821	42	$328,543
2015	101	$273,285	42	$299,480

Other witnesses in this case present testimony concerning deficiencies in Liberty's capital budgeting process, specifically, that projects have been undertaken without appropriate analysis of alternatives and that cost estimates have varied significantly from actual construction costs. These conclusions apply to the Training Center as well.

[8] Attachment AI-3
[9] In this Table, the training costs include the cost technical training staff, travel time to the training centers and training hours multiplied by times employee hourly pay. Attachment AI-4

Q. What is your opinion about Liberty's assertion that it could not find local training resources?

A. It is not clear what steps Liberty took in its search for an alternate provider for training. Liberty stated that "Utilization of third party training facilities and instructors causes limited availability and often times conflicts with operational requirements."[10] Yet, the other combined gas and electric utility in New Hampshire [11] does not own a training center. UES relies on contracted instructors and local technical institutions for its training needs, including hands-on training. Staff is not aware of any instance where UES could not meet its training requirements because of unavailability of such services in New Hampshire or elsewhere.

Q. What is your opinion on the method used by the Company to allocate the costs of the Training Center between EnergyNorth and Granite State?

A. The lease provides that the annual costs of the training center be allocated using the ratio of EnergyNorth's and Granite State's union employee. There are different training requirements for gas and electric employees, and thus the number of employees might not reflect actual usage of the Training Center. Staff believes that a more consistent and reasonable allocation could be made using the proportion of training hours for management and union trainees of Granite State and EnergyNorth, on average over the immediate past 3 years. Given that the rationale for building the Training Center is to meet training needs of management and union employees, and given that environmental and safety training does not require a special training center, Staff believes that it is

[10] Attachment AI-5 (DG 14-180, Staff 2-6)
[11] Unitil Energy Systems ("UES"), which serves 103,500 electric customers and 78,700, natural gas customers in Maine, Massachusetts and New Hampshire, and employs 500 employees of which 159 are union employees. (Source : Annual Report 2015)

reasonable to exclude environmental and safety inputs from the cost allocation method. Using the 3-year average proportion of management and union employees, Granite State would bear 36.5% of the Training Center cost instead of the 25% proposed by Liberty.

Q. Do you have any other comments?

A. The installed cost of the Training Center increased substantially from the estimated figure submitted in DG 14-180 (Brouillard testimony from DG 14-180, Bates page 0175, line 16). The estimate was $1.45 million and the actual, installed cost is $4.10 million (DA 16-560 Staff 1-6). This suggests that Liberty did not adequately research the cost to build, equip and furnish the Training Center prior to making the decision to build it. The disparity between the original estimate and the actual cost of the Training Center raises questions about the adequacy of the Liberty review of other options available to meet its training requirements and the cost of those options. Without accurate data, the results of any cost/benefit analysis cannot be relied upon. Table-5, below, shows the cost of training in the two years prior to the opening of the Training Center and training costs after the training center commenced operations in March 2015.[12] This Table shows no reduction in Granite State's training costs after the Center was opened.

[12] These costs do not include National Grid Instructor costs, and Staff Tech 1-3 does not show any incremental instructor cost for training in-house at the training center.

Table 5: Annual Training Cost[13]

	Energy North			Granite State			Safety/Symposium	Grand Total
	Actual Cost (Man+Union+Env)	Training Center Cost	Total	Actual Cost (Man+Union+Env)	Training Center Cost	Total		
2013	$288,163	$0	$288,163	$291,485	$0	$291,485	$98,131	$677,779
2014	$325,724	$0	$325,724	$346,394	$0	$346,394	$107,476	$779,595
2015	$305,302	$439,678	$744,980	$325,787	$146,559	$472,346	$116,822	$1,334,148

Q. **What is your recommendation for the Commission?**

A. The lack of reliable analysis and support provided in this docket for the Training Center limits Staff's ability to sufficiently analyze and quantify the impact of this investment. The analyses that were submitted do not indicate that building the Training Center produced savings to Granite State or will result in future savings, but rather increased training costs. There is also a concern as to how Training Center costs are being allocated between Granite State and EnergyNorth. Therefore, Staff recommends that the Commission not allow recovery of the Training Center expenses of $146,559 included in RR-3-12 (CU) (Bates page 040). Given that 75% of the costs are allocated to EnergyNorth, and Liberty expects to petition the Commission for an increase in delivery rates in 2017, the Commission will be able to revisit this issue in that docket if it so chooses.

Q. What information does Staff recommend Liberty provide to assist in the evaluation of the decision to build the Training Center?

[13] Based on Attachment AI- 4 (Staff Tech 1-3)

A. To be able to analyze and quantify the incremental cost of the Training Center, and allocate costs, Staff believes that the following information is essential:

- Training requirements by position and number of positions (Qualification vs. Training);
- Training options available and cost of each option (Q vs T);
- RFPs issued for training services (Q vs T);
- Consideration and efforts to provide training to others for profit;
- Business case provided corporate to support proposed training center;
- Revenue requirement related to the training center (capital & operating);
- Long term Cost/Benefit analysis comparing annual revenue requirement to cost of alternative options;
- Training Center calendar from March 1, 2015 to present that includes all scheduled events, event hours and attendees.

Q. Does that conclude your testimony?

A. Yes.

BUSINESS CASE

PROJECT TITLE: LIBERTY UTILITIES TRAINING CENTER

PROJECT SPONSOR: MICHAEL KNOTT
PROJECT LEAD: STEPHEN SZCZECHURA
DATE: 1/24/2014
PROJECT ID: 8840-C18772
BUSINESS PLAN NUMBER: (Assigned by Corporate Finance)

RECOMMENDATION:

To build a training center on company owned property in Concord, NH. This facility will provide training to our gas and electric employees, contractors and local first responders. There is the potential for providing training to other utilities on a fee basis.

OBJECTIVE(S)

To build a training center to serve Liberty Utilities employees that will be located in New Hampshire. Currently employees are sent to other utilities training sites out of state to complete mandated yearly training.

BACKGROUND

The project will consist of ground up construct of the Liberty Utilities Training Center building to be located at 10 Broken Bridge Rd in Concord NH. There will be site work for a foundation, septic system and asphalt parking area. The masonry building will consist of office space, first and second floor classroom space, high bay lab / training area with a mezzanine, lunch room, standard and ADA compliant restrooms. A well for potable water and fire suppression will also be installed.

ALTERNATIVES/OPTIONS

Training can be provided at National Grid's Training Facility in Millbury, MA. The estimated cost for having an outside agency provide training is $400,000/year.

FINANCIAL ASSESSMENT

Simple ROI for the project has payback in less than 3 years.

RISK ASSESSMENT AND QUALITATIVE EVALUATION

No risks foreseen if construction schedule is met.

IMPLEMENTATION/ACTION PLAN

Upon completion of architectural redesign the project will be sent to competitive bid. Anticipate a June start for construction with completion in November.

REVIEWED BY:

PROJECT LEADER:
STEPHEN SZCZECHURA

DIRECTOR/VP:

FINANCE:

LIBERTY UTILITIES - CAPITAL PROJECT EXPENDITURE APPLICATION

DIVISION/COMPANY: LU- New Hampshire ENI		HOME OFFICE REF #:
PROJECT TITLE: Liberty Utilities Training Center		EXPECTED PROJECT TOTAL: $1,028,100
PROJECT TYPE (circle one):	System Maint / System Project / ***Growth*** / LXA	
PROJECT START DATE: June, 2014		PROJECT END DATE: November, 2014
CURRENT UTILITY EARNINGS STATUS:		JOB COST/FWO #:

Type of Capital Project:

X **Growth**

☐ **Improvement Upgrades**

☐ **Infrastructure Replacement**

PROJECT DESCRIPTION & LOCATION:

The project will consist of ground up construct of the Liberty Utilities Training Center building to be located at 10 Broken Bridge Rd in Concord NH. There will be site work for a foundation, septic system and asphalt parking area. The masonry building will consist of office space, first and second floor classroom space, high bay lab / training area with a mezzanine, lunch room, standard and ADA compliant restrooms. A well for potable water and fire suppression will also be installed.

IS THIS PROJECT GROWTH RELATED? IF "YES", DESCRIBE THE SPECIFIC LOCATION (MAP) AND LIST APPLICABLE DEVELOPERS WHERE GROWTH WILL OCCUR (CONSULT WITH DEVELOPMENT SERVICES REGARDING FUNDING). Not Operation related

PERMITTING REQUIREMENTS, INCLUDING POTENTIAL IMPACT ON EXISTING PERMITS, AND TIMING OF AND RISKS ASSOCIATED WITH OBTAINING APPROPRIATE PERMITS FOR PROJECT.
Building permits will need to be secured from the City of Concord. Wetland permits will be needed from NHDES. Delays in permits will impact a December completion.

COST ESTIMATE FOR TOTAL PROJECT, NATURE OF ESTIMATE (FIRM FIXED PRICE, INTERNALLY OR EXTERNALLY GENERATED), TIMING OF SPENDING BY QUARTER, AND RISKS ASSOCIATED WITH COST ESTIMATES.
Cost estimate for total project provided by CMK Architects.

WILL THERE BE ASSETS GREATER THAN $5,000 THAT ARE CURRENTLY IN SERVICE REMOVED AS A RESULT OF THIS PROJECT?
NO.

IF YES, PLEASE DETAIL THE SPECIFIC ASSETS THAT WILL BE REMOVED:

1. Original Cost of Plant to be removed (if known):
2. What is the replacement cost of the plant being removed (if original cost not known)?
3. Original Work Order of Plant to be removed (if known):
4. Is the Plant being removed reusable?
5. What is the year of original installation of the plant being removed?

Business Case

PROPOSED SOURCE OF FUNDS (COMPANY, DEVELOPER LXA, HUF, ETC.)

Energy North CapEx

CATEGORY & STATUS OF PROJECT		FINANCIAL SUMMARY		
(tick as appropriate)		NEXT ANTICIPATED TEST YEAR		
		Rate Recovery (over 18 months)		
Safety	X	Will this, and other approved projects, cause a rate shock		If yes, is customer affordability an issue?
Mandated				
Impending Regulatory Obligation	**X**			
Rate Recovery-Immediate Return		Have Health & Safety implications been considered?	Yes	
Rate Recovery (3 to 6 months)		Has Environmental Compliance review been done?	Yes	
Rate Recovery (6 to 12 months)		Has Tech Services review been done?	Yes	
Rate Recovery (12 to 18 months)				
Was this Capital Expenditure included in the Annual Budget?	Yes	What amount was budgeted? $1,028,100		

ANALYSIS OF PROJECT VALUE		CAPITAL EXPENDITURE BUDGET UTILIZATION			
			Authorized Amount	To be spent in: Current Year	Future Years
Design/Engineering	$70,000				
Material	$351,240				
External contractor costs	$439,050				
Internal costs	$15,000	(A) Capital budget	$1,028,100	X	
Other costs (contingency)	$87,810	(B) Over (under) run vs. Budget			
Soft Costs	$65,000	(C) (A+B) Total Estimated Project Cost	$1,028,100		
		(D) Less Approved Spend to Date			
		(E) Less Future Approval Requests			
Project Total Cost	$1,028,100	(F) (C-D-E) Approval Amount Requested (current application)			

	Name	Signature	Date		
Requesting Party	Stephen Szczechura		01/28/2014		
President – LU East	Richard Leehr				
Vice President Finance	Kevin McCarthy				
CFO					
CEO					

BUSINESS CASE

PROJECT TITLE : **EN INSTALL TRAINING CENTER / CONCORD NH SPECIFIC**

PROJECT SPONSOR: **CHRIS BROUILLARD**

PROJECT LEAD: **STEVEN SZCZECHURA**

DATE: **5/1/2014**

PROJECT ID: **8840-C18772**

BUSINESS PLAN NUMBER:

RECOMMENDATION:

Install training center at Broken Bridge in Concord, NH.

BACKGROUND

This specific project will provide Liberty Utilities a training center in Concord NH; implementing our business strategy / transitioning from National Grid's training facility.

ALTERNATIVES/OPTIONS

None

FINANCIAL ASSESSMENT

None.

RISK ASSESSMENT AND QUALITATIVE EVALUATION

None

IMPLEMENTATION/ACTION PLAN

The construction will take place during 2014.

REVIEWED BY:

DIRECTOR/VP: 

FINANCE:

LIBERTY UTILITIES - CAPITAL PROJECT EXPENDITURE APPLICATION

DIVISION/COMPANY: **Capital / Energy North Co.**	HOME OFFICE REF #: **8840-C18772**
PROJECT TITLE: **EN-Install Training Facility Concord NH Specific**	EXPECTED PROJECT TOTAL: **$1,053,100**
PROJECT TYPE (circle one): System Maint **/ System Project** / Growth /	
PROJECT START DATE: **1/1/2014**	PROJECT END DATE: **12/31/2014**
CURRENT UTILITY EARNINGS STATUS:	JOB COST/FWO #:

Type of Capital Project:

- ☐ **Growth**
- ■ **Improvement Upgrades**
- ☐ **Infrastructure Replacement**

PROJECT DESCRIPTION & LOCATION:
Specific project will provide Liberty Utilities a training center in Concord NH. We are transitioning from National Grid's training center and implementing our business strategy.

IS THIS PROJECT GROWTH RELATED? IF "YES", DESCRIBE THE SPECIFIC LOCATION (MAP) AND LIST APPLICABLE DEVELOPERS WHERE GROWTH WILL OCCUR (CONSULT WITH DEVELOPMENT SERVICES REGARDING FUNDING).
No

PERMITTING REQUIREMENTS, INCLUDING POTENTIAL IMPACT ON EXISTING PERMITS, AND TIMING OF AND RISKS ASSOCIATED WITH OBTAINING APPROPRIATE PERMITS FOR PROJECT.
Licensing and Environmental Permitting as required.

COST ESTIMATE FOR TOTAL PROJECT, NATURE OF ESTIMATE (FIRM FIXED PRICE, INTERNALLY OR EXTERNALLY GENERATED), TIMING OF SPENDING BY QUARTER, AND RISKS ASSOCIATED WITH COST ESTIMATES.
Cost estimates will be calculated on an individual job basis.

WILL THERE BE ASSETS GREATER THAN $5,000 THAT ARE CURRENTLY IN SERVICE REMOVED AS A RESULT OF THIS PROJECT?

None

IF YES, PLEASE DETAIL THE SPECIFIC ASSETS THAT WILL BE REMOVED:

1. Original Cost of Plant to be removed (if known): **Not known**
2. What is the replacement cost of the plant being removed (if original cost not known)? **Not known**
3. Original Work Order of Plant to be removed (if known): **Not known**
4. Is the Plant being removed reusable? **No**
5. What is the year of original installation of the plant being removed? **None**

PROPOSED SOURCE OF FUNDS (COMPANY, DEVELOPER LXA, HUF, ETC.)

The 2014 Approved Capital Budget.

CATEGORY & STATUS OF PROJECT (tick as appropriate)	
Safety	
Mandated	
Impending Regulatory Obligation	**X**
Rate Recovery-Immediate Return	**X**
Rate Recovery (3 to 6 months)	
Rate Recovery (6 to 12 months)	
Rate Recovery (12 to 18 months)	
Was this Capital Expenditure included in the Annual Budget?	**Yes**

FINANCIAL SUMMARY		
NEXT ANTICIPATED TEST YEAR		
Rate Recovery (over 18 months)	**X**	
Will this, and other approved projects, cause a rate shock	**No**	If yes, is customer affordability an issue?
Have Health & Safety implications been considered?	**Yes**	
Has Environmental Compliance review been done?	**Yes**	
Has Tech Services review been done?	**Yes**	

ANALYSIS OF PROJECT VALUE	
Design/Engineering	
External contractor costs	
Internal costs	
Other costs (contingency)	
Working capital requirements	
Project Total Cost	**$1,053,100**

CAPITAL EXPENDITURE BUDGET UTILIZATION

	Authorized Amount	To be spent in: Current Year	Future Years
(A) Capital budget	**$1,053,100**	**$1,028,100**	**$25,000**
(B) Over (under) run vs. Budget			
(C) (A+B) Total Estimated Project Cost			
(D) Less Approved Spend to Date			
(E) Less Future Approval Requests			
(F) (C-D-E) Approval Amount Requested (current application)			

	Name	**Signature**	**Date**		
Requesting Party	Chris Brouillard	C.P. Brouillard	5/1/2014		
President – LU Central					
Vice President Finance					
CFO					
CEO					

Attachment:

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

DA 16-560
Affiliate Agreement with Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities related to Concord Training Center

Staff Data Requests - Set 2

Date Request Received: 6/21/16
Request No. Staff 2-3

Date of Response: 7/1/16
Respondent: Mark Smith

REQUEST:

Ref. Response of Staff 1-4. Did Liberty perform any cost-benefit analysis concerning use of the training center? Identify and quantify all major and minor benefits and costs analyzed. Provide details with supporting analysis and work papers.

RESPONSE:

Yes, Liberty performed a cost benefit analysis concerning the use of the training center. The analysis was based on economic factors as well as non-economic factors. A cost estimate of utilizing the National Grid training facility in Millbury, Massachusetts was approximately $375,000 per year, which included an analysis of six months of use by gas employees and 12 months of use by electric employees during 2013. See Attachment Staff 2-3.xlsx. That cost estimate includes incremental travel time and instructor's charges combined for electric and gas employees. It does not include the employee's basic hourly pay rate which would have been incurred regardless of where the training was held. As the cost estimate was based on the number of employees who attended training during that time period, the cost estimate is significantly less than the amount that would be calculated based on the amount of training that has been conducted and will be conducted going forward at the Liberty training center, as discussed below.

In addition to cost, other factors played a major role in the decision process. The arrangement with National Grid was temporary, like the Transition Service Agreements (TSAs) between Liberty and National Grid. Liberty did not have a written TSA with National Grid for training but did have a verbal commitment from National Grid to provide training services for a reasonable period of time until Liberty was ready to assume this obligation. When training in Millbury, Liberty employees were part of classes which included National Grid employees from Massachusetts and/or Rhode Island. Consequently the training they received was not specific to New Hampshire and in some cases conflicted with New Hampshire practices and procedures. Also, scheduling New Hampshire employees for this training was becoming increasingly difficult as Liberty employees were slotted into classes based on when openings were available. Priority was given to the National Grid employees. In many cases, the timing of available openings was in conflict with operational needs. Liberty also searched the local area for another source of training and found no gas or electric training available that would in any way come close to meeting our needs. Consideration was given to utilizing an existing Liberty facility. The only facility reasonably centrally located and of sufficient size was a building in the Manchester yard. However, due to environmental and permitting issues, it was ruled out. For all of the above reasons the decision was made to build a training center.

Operator Qualifications (OQs) testing is also performed at the training center. Prior to construction of the training center, OQ testing was done using site visits to the various operating yards with testing logistics and conditions varying from site to site. Gas OQ testing criteria have also recently changed. As OQs expire, there is a new requirement to demonstrate proficiency by physically performing the respective task in addition to the current requirement to pass the written test. This requires even greater use of the training center as it allows the instructor to assess the individual's ability to perform the tasks in a controlled environment rather than in the field which is more difficult as logistics and conditions at the yards varied. There are approximately eighty-five OQ tasks. While every employee is not required to pass them all, each employee does have to pass a number of them. Specific OQ tasks vary by job function. Since it now controls the scheduling of training, Liberty is able to train and test more employees more efficiently than when Liberty relied on National Grid for training. In addition, local training keeps employees in the area and able to respond to an emergency situation if needed. The training center is also being used for basic gas and electric training for all non-field employees to provide them with a better understanding of the business. Such training would not have been possible with National Grid's facility given the constraints on use of that facility. To date, approximately 110 employees have been through this basic training. Liberty also plans to use the training center for public awareness training with first responders such as fire departments and police. It will also be used in our outreach efforts with technical high schools and colleges to educate students in careers in the utility industry. For all these reasons having a Liberty training facility provides many quantifiable and non-quantifiable benefits to the Company, its employees, customers and the communities served by Liberty.

GAS and ELECTRIC OPERATIONS National Grid BASED VS. IN-HOUSE TRAINING ANALYSIS

GAS OPERATIONS National Grid

TRAINING IF PERFORMED BY National Grid:	# TRAINEES	HOURLY O.T. EXP.	AVE. DAILY TRAVEL HRS.	REQ. DAYS	INCURRED O.T. TRAVEL COST	INCURRED National Grid Instructor COST: $360/DAY per Student
MANAGEMENT (new):	1	$0.00	4	20	$0.00	$7,200.00
UNION (new):	7	$52.50	4	20	$29,400.00	$50,400.00
Changing Positions / Departments						
MANAGEMENT:	0	$0.00	0	0		$0.00
UNION:	8	$52.50	4	20	$33,600.00	$57,600.00
ANNUAL SUB-TOTALS:					$63,000.00	$115,200.00
TOTAL ANNUAL ESTIMATED TRAINING EXPENSES BY National Grid - O.T. + Instructor Cost:						$178,200.00

ELECTRIC OPERATIONS National Grid

MANDATORY ANNUAL EXPERT & SAFETY COMPLIANCE TRAINING IF PERFORMED BY National Grid:	# TRAINEES	HOURLY O.T. EXP.	AVE. DAILY TRAVEL HRS.	REQ. DAYS	INCURRED O.T. TRAVEL COST	INCURRED National Grid Instructor COST: $360/DAY per Student
MANAGEMENT:	16	$0.00	6	3	$0.00	$17,280.00
UNION:	26	$67.50	6	3	$31,590.00	$28,080.00
REQUIRED PROFICIENCY / REFRESHER IF PERFORMED BY National Grid for existing employees:						
MANAGEMENT:	0	$0.00	0	0		$0.00
UNION:	26	$67.50	6	6	$63,180.00	$56,160.00
ANNUAL SUB-TOTALS:					$94,770.00	$101,520.00
TOTAL ANNUAL ESTIMATED TRAINING EXPENSES BY National Grid - O.T. + Instructor Cost:						$196,290.00
ANTICIPATED Annual Incremental training expenses for a replacement Lineworker if replaced with a rated Lineworker:						
UNION:	1	$67.50	6	30	$12,150.00	$10,800.00
ADDITIONAL TOTAL O.T. + Instructor Cost:						$22,950.00

Total Cost For Gas and Electric **$374,490.00**

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 4

Date Request Received: 7/7/17 Date of Response: 7/21/17
Request No. Staff 4-24 Respondent: Steven Mullen

REQUEST:

Reference Docket DE 16-383, Rebuttal Testimony of Mr. Smith & Mr. Mullen, Bates page 227-228. Please provide list of organizations Liberty reached out to explore possible alternatives to National Grid's training arrangement. Please provide supporting documents of such efforts.

RESPONSE:

As stated in that section of testimony, training through National Grid is "no longer available," so Liberty was not seeking an alternative to that training, it was determining a replacement for that training.

Based on information provided to me by Liberty's trainers, Company personnel contacted management employees at Unitil Energy Systems (UES), New Hampshire Electric Cooperative (NHEC), and Green Mountain Power (GMP) and discussed their current training methods. UES and NHEC train on the job with the training conducted by supervisors rather than dedicated trainers. GMP has a dedicated trainer who performs classroom and field based training. Based on the contact at that time, GMP's trainer had no ability to perform training for additional people.

As stated on Bates 229 of the referenced rebuttal testimony, Liberty also reached out to Eversource and conducted a few training sessions in 2014 at Eversource's Pittsfield training facility. Eversource subsequently closed that facility.

Attachment Staff 4-24 is a copy of an invoice for some of the training sessions conducted in June 2014 at the Eversource facility. I am not aware of any documentation regarding the other entities that were contacted as discussed above.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 2

Date Request Received: 6/16/17 | Date of Response: 6/30/17
Request No. Staff 2-26 | Respondent: Daniel Dane

REQUEST:

Reference Attachment DBS/DSD-2, Schedule RR-EN-3-10, Page 1 of 1 (Bates 057), Lines 28-32 – Concord Training Center: The pro-forma adjustment appears to indicate there was an effective decrease in the annual rental expense intercompany credit amount from $146,559 (5/1/16 – 4/30/17) to $95,930 (5/1/17 – 4/30/18). (See also RR-EN-3-10 WP). Please explain.

RESPONSE:

The rental expense for the Concord Training Center is to be updated on May 1 of each year, per the Training Center Lease Agreement. The amount of the expense is based on EnergyNorth's annual costs of ownership of the Concord Training Center. Per the Company's calculation of EnergyNorth's costs of ownership for the period May 1, 2017 to April 30, 2018, the costs will decrease from the prior year, resulting in the *pro forma* reduction shown in DBS/DSD-2, Schedule RR-EN-3-10.

As indicated in both Docket No. DA 16-560 and Docket No. DE 16-383, the $146,559 was derived using a combination of actual and estimated amounts as it was for the initial year of the lease and a full year of actual costs had not yet been experienced. The $95,930 was calculated in advance of the rate case filing and involved some estimated costs as actual costs for the lease year ended April 30, 2017, were not yet fully available. Following the completion of the lease year and after submittal of the rate case filing, the lease amount was recalculated using actual amounts as well as an updated count of union employees to determine Granite State's Proportionate Share (as defined in the Lease Agreement). The updated count of union employees was 37 for Granite State and 147 for EnergyNorth, resulting in Granite State's Proportional Share to be 20.11% versus EnergyNorth's at 79.89%. The recalculated lease amount for Granite State is $96,764. The amount of lease revenue to be received by EnergyNorth will be adjusted by $834 as part of the Corrections and Updates filing.

Please see Attachment Staff 2-26 for a comparison of the calculation of the $146,559 and the $96,764.

Concord Training Center
Annual Determination of Lease Payment

	Year 2 (Commencing May 1, 2017)		Initial Year Estimate		Difference	Comments
Cost of building on books, 4/30/2017	$ 3,824,673.56		$ 4,109,880		$ (285,206.44)	Mostly reclassified expenditures to another job; see tab FA 106<>0317
Accum Depr thru 4/30/2017	$ (261,669.64)		$ (118,365)		$ (143,304.64)	Depreciated more months
NBV as of 4/30/2017	$ 3,563,003.92		$ 3,991,515		$ (428,511.08)	
Return @ EnergyNorth WACC of 7.05%	$ 251,191.78		$ 281,401.81		$ (30,210.03)	
Annual Book Depreciation	$ 129,788.49		$ 118,364		$ 11,424.49	EN rate case utilized various depreciation rates by FERC code. Initial year used a blended rate
Annual Property and Liability Insurance	$ 349.55		$ 1,500		$ (1,150.45)	EN Rate Case based on gross book value allocation; Intial year was an estimate
Utilities (gas, electric, communications)	$ 20,031.11		$ 39,762		$ (19,730.89)	EN Rate Case based on actual; Initial year based on annualized 4 months of actuals
Property Taxes	$ 28,516.33		$ 30,210		$ (1,693.67)	Both from tax bills
All other Admin and O&M	$ 51,328.69		$ 115,000		$ (63,671.31)	Initial year based on estimates; EN Rate Case based on actuals
Total	$ 481,205.95		$ 586,238		$ (105,031.86)	
Percentage to GSE - Annual	$ 96,764.24	20.11%	$ 146,559	25%	$ (49,795.21)	
(Monthly GSE)	$ 8,063.69					
Percentage to EN - Annual	$ 384,441.71	79.89%	$ 439,678	75%	$ (55,236.65)	Higher allocation to EN but lower total costs for EN Rate Case
(Monthly EN)	$ 32,036.81					

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 4

Date Request Received: 7/7/17 Date of Response: 7/21/17
Request No. Staff 4-26 Respondent: Steven Mullen

REQUEST:

Reference Docket DE 16-383, Rebuttal Testimony of Mr. Smith & Mr. Mullen, Bates page 229-230. Did Liberty perform any financial/economic analysis of the efficiency gain described here? If yes, please provide the analysis. If not, please explain why not?

RESPONSE:

The referenced section of the DE 16-383 rebuttal testimony discusses the efficiencies obtained from use of the training center by not having to rely solely on on-the-job training, by not having the gas and electric trainers traveling to multiple work locations to train small groups of employees, and by not requiring supervisors to provide training rather than dedicated training personnel. Even without any financial analysis, it is clear that each of those training conditions offers efficiencies in terms of consistency of training, scheduling, planning, travel time, and controlled training conditions, among other things.

While the cost of training is always a consideration, it is vital to keep in mind that the timing and adequacy of training for employees is a top priority. The Company must ensure that it has field trained, knowledgeable employees who can perform their jobs safely and competently. This is the primary consideration in ensuring the safety of our workers as well as providing safe and reliable service.

Regarding the efficiency gains referenced in the testimony, a financial/economic analysis was not performed as attempting to quantify the gains would have involved complex analyses of a number of variable factors including travel distances, number of employees who could be trained at each job location, ability of supervisors to take time from other job tasks to perform training, variability in training among supervisors, potential follow-up training due to that variability, ability to train specific tasks due to job site conditions, ability of training personnel to effectively schedule training at numerous locations, etc. Thus, the results of any financial/economic analysis would be highly variable, subject to a range of challenges, and thus of questionable value.

APPENDIX B: Business Case Template

BUSINESS CASE

PROJECT TITLE	
PROJECT SPONSOR:	
PROJECT LEAD:	
DATE:	
PROJECT ID	
BUSINESS PLAN NUMBER:	(Assigned by Corporate Finance)

Recommendation:

- Brief Description of what is being recommended and why. What problem are we trying to resolve?
- Indicate if it is for:
    - Release of Funds (approval to spend) under a previously approved business case or budget.
    - Approval of a Budgeted Project
    - Approval of a New Project not in current budget
- Under all scenarios outline the total dollar value of the plan, the amount of funds to be released now, and the amount(s) and timing of future funds to be released.
- Amount of funds allotted to OM&A and amount of funds allotted to Capital.
- Scope of project (What work activities, equipment needed, man hours, customer interruptions, etc)
- Expected start date and finish date.

Objective(s)

Describe the major measurable result that is to be achieved. Do not state the recommendation as the required result.

Background

- Describe the current situation and the background leading up to it. (Answer the question of why do we need to do anything?)
- Describe any related project previously approved for this project and any funds previously spent that are related to this proposal.
- Describe the decision criteria used in evaluating the alternatives. i.e. Work process improvement, system improvement, etc.
- Describe any restrictions or conditions, which must be satisfied and would affect the decision or restrict the acceptance of some alternatives. i.e. safety, minimum service level, etc.

Alternatives/Options

Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected. Discuss Status Quo, Postponement, Buy vs Rent vs Build options.

- Pros, Cons, & Risks of each alternative Tables.

Financial Assessment

- Corporate Finance Division can provide support in completing this section, as required.
- Brief description of financial assessment for each option

- Table or Chart ideal for summarizing data, with any spreadsheets used attached as an appendix.
- NPV should be used for all projects, unless there is only one viable alternative, the recommendation is based on non-economic criteria, or it is obvious that one alternative is much more economically viable than the others. (Provide details of reason)
- Discuss the results of the evaluation, indicating which alternative is best, and any relevant financial issues.
- Identify whether adequate funds are available in the budget. If funds are not available, identify tradeoffs to accommodate the work, or rationale for increasing the budget.
- If expenditures are incurred for more than one year, show annual cash flows for the controlling unit(s).
- Identify any staff level impacts.

Risk Assessment and Qualitative Evaluation

- Not all decisions will be based on lowest cost – qualitative factors can drive the decision.
- Discuss any risks and uncertainties associated with the recommended alternative. Including: Safety, Economic, Operational, Technical, Environmental, Social/Political, Customer Impact, and Regulatory Issues.
- Discuss any other qualitative factors, which may affect this decision.

Implementation/Action Plan

Bullet points of implementation time line, including major hurdles such as approval, work start, cash flows, completion date.

Reviewed by:

Project Leader:

Director/VP:

Finance:

APPENDIX C: Capital Project Expenditure Application Form

Liberty Utilities

Capital Expenditure Application 2015

Requesting Region or Group:		**Date of Request (MM/DD/YY):**	Click to select date
Project Name:			
Requesting Region:		**Sponsor** (Name):	
Project Start Date:	Click to select date	**Project Completion Date:**	Click to select date
Requested Capital ($)		**Expenditure Included in Approved Budget?**	☐Yes ☐No
Project Type: (Click appropriate box)	☐ Safety ☐Mandated ☐Growth ☐ Regulatory Supported ☐Discretionary	**Nature of Estimate:** (Click appropriate box)	☐Fixed or Firm Price ☐Estimate – Internal ☐Estimate - External ☐Other (specify details)

Details of Request

Project description

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure? If yes, please detail the specific assets that will be removed: 1. Original Cost of Plant to be removed (if known): 2. What is the replacement cost of the plant being removed (if original cost not known)? 3. Original Work Order of Plant to be removed (if known): 4. Is the Plant being removed reusable? 5. What is the year of original installation of the plant being removed

What alternatives were evaluated and why were they rejected?

What are the risks and consequences of not approving this expenditure?

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.

Please describe the Regulator's perspective on this expenditure and the necessity to complete related projects?

Are there other pertinent details that may affect the decision making process?

Financial Summary

Next Anticipated Test Year	Click to select a date	**Will this add material rate shock?**	
Rate Recovery (Click appropriate box)	☐Immediate ☐3 to 6 months ☐6 to 12 months ☐12 to 18 months ☐Over 18 months		
	Current Year	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Contingency ($)			
Other ($)			
Total ($)			

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 4

Date Request Received: 7/7/17
Request No. Staff 4-32

Date of Response: 7/21/17
Respondent: Steven Mullen

REQUEST:

Reference Docket DG 17-048, Testimony of Mr. Mullen, Bates page 023-027. Did Liberty perform any financial/economic analysis related to the benefits described here? If yes, please provide the analysis with supporting work papers.

RESPONSE:

Bates 023-027 of my testimony include descriptions of various topics such as the types of gas and electric training infrastructure installed at the Training Center, the different types of training available at the facility, flexibility of scheduling, the ability to train non-field employees on gas and electric utility topics, and the ability to make the facility available at times to accommodate training-related events including outside parties. While some of those items may involve quantifiable benefits, the majority involve non-quantifiable benefits. Hence, there is no analysis responsive to this request.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 5

Date Request Received: 7/27/17 Date of Response: 8/10/17
Request No. Staff 5-40 Respondent: Steven Mullen

REQUEST:

Reference Docket DE16-383, Rebuttal Testimony of Mr. Smith & Mr. Mullen, Bates 229, lines 19-20. Please explain the basis of the conclusion that "exclusive reliance of on-the-job training is insufficient to ensure employees are able to fully learn and safely perform their function." Please provide analyses, rules/standards, studies etc. which supports this conclusion.

RESPONSE:

The full sentence from the cited rebuttal testimony which begins on line 17 is as follows:

> *"The Company also considered on-the-job training, without any classroom or controlled environment, but ruled it out for several reasons, mostly because reliance o[n] (sic) on-the-job training is insufficient to ensure employees are able to fully learn and safely perform their functions."*

Classroom instruction and controlled environment training are necessary aspects of a well-rounded training experience as they introduce efficiency and consistency which benefits employees, the Company and, ultimately, customers. By conducting classroom training, multiple employees simultaneously receive identical training. Such training is not only efficient from a scheduling perspective, it is also cost efficient. Controlled environment training ensures that employees receive training on certain techniques and procedures under the same conditions, thus ensuring that the training received is standardized from employee to employee. While certainly on-the-job training is vital to an employee's job knowledge and experience, it is the Company's view that "exclusive" reliance on that training method would not provide the optimal training experience. That position is the result of the collective experience of numerous Company personnel who have been involved in the gas and electric utilities for many, many years. Thus, no particular analyses or studies were necessary.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 5

Date Request Received: 7/27/17 | Date of Response: 8/10/17
Request No. Staff 5-42 | Respondent: Steven Mullen

REQUEST:

Reference Docket DE16-383, Rebuttal testimony of Mr. Smith & Mr. Mullen, Bates 228, lines 1-2, DG 17-048 response Staff 4-24.

a. Please explain why the UES method (on the job training by supervisors) was not and still is not a viable option for Liberty?

b. Did Liberty issue RFPs (or take other similar steps) for training services before deciding to build Training Center? Please provide supporting documentation.

RESPONSE:

a. As explained in the response to Staff 4-26, in the Company's view, on-the-job training performed by supervisors, while a possible method of providing training, has inherent inefficiencies that are avoided through the use of a centralized training facility. Those inefficiencies include:

- Diverting the actions of supervisors from the additional tasks they are required to perform in the course of their normal duties;
- Potential inconsistency in the training provided by individual supervisors;
- Potential inconsistency in the training provided from job site to job site based on particular conditions experienced at each site; and
- Scheduling and planning concerns.

In addition, please see the response to Staff 5-40 for a discussion of the Company's decision to not rely on the exclusive use of on-the-job training.

b. As explained in the response to Staff 4-24, although Liberty did not issue RFPs, Liberty did reach out to other regional utilities to explore training alternatives. Please also see Bates 228-230 of the Smith/Mullen rebuttal testimony in Docket No. DE 16-383 for other alternatives explored, including potential use of other exiting Company property or acquiring a new piece of property. Please also refer to Attachment SEM-1 to my testimony for further discussion of factors taken into account in the decision making process and avenues explored.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 5

Date Request Received: 7/27/17 | Date of Response: 8/10/17
Request No. Staff 5-43 | Respondent: Steven Mullen

REQUEST:

Reference Docket DE16-383, Rebuttal testimony of Mr. Smith & Mr. Mullen, Bates 231, lines 6-8 and DG 17-048 response of Staff 4-24 and Staff 4-33. Please explain why Liberty did not perform a comparative financial/economic analysis between the option it ultimately selected (training center) and an alternative option (e.g. UES method of on the job training by supervisors, or use of IBEW facility, or others)?

RESPONSE:

None of the referenced sources discussed the performance of a financial/economic analysis. The cited portion of the DE 16-383 rebuttal testimony discussed Staff's lack of support for a position taken in its DE 16-383 testimony, the response to Staff 4-24 discussed Liberty's outreach efforts to other utilities, and the response to Staff 4-33 discussed training methods used by contractors.

None of the topics discussed in the cited references were viable alternatives for providing the range of gas and electric training needs required by Liberty, so no financial/economic analysis of those options was warranted. With respect to on-the-job training, please see the responses to Staff 5-40, Staff 5-42, Bates 229-230 of the Smith/Mullen DE 16-383 rebuttal testimony, and Bates 021 of my testimony in the current docket.

Please see Attachment SEM-1 to my testimony for a discussion of a financial analysis that was performed.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 5

Date Request Received: 7/27/17
Request No. Staff 5-44

Date of Response: 8/10/17
Respondent: Steven Mullen

REQUEST:

Reference Docket DE16-383, Rebuttal testimony of Mr. Smith & Mr. Mullen, Bates 232, lines 13-19 and DG 17-048 response of Staff 4-28. In the context of these cost increases, did Liberty explore any alternatives? Please explain why or why not in detail.

RESPONSE:

Alternatives explored and the reasons for not pursuing those alternatives are discussed in the Smith/Mullen DE 16-383 rebuttal testimony, the Mullen DG 17-048 testimony, and the responses in DG 17-048 to Staff 4-24, Staff 4-25, Staff 4-30, Staff 5-40, Staff 5-42, and Staff 5-43.

As explained in the DE 16-383 rebuttal testimony as well as the testimony in the current docket, building a local gas and electric training facility was determined to be the best solution to the long-term training needs for Liberty's employees. As construction conditions for the Training Center changed, cost increases were analyzed based on change orders, information received from contractors, and other relevant documentation. Cost increases were reviewed, analyzed, and approved as they arose. Note that the Audit Division also reviewed the Training Center capital costs as part of its audit in this proceeding.

Despite the increases in cost from the original estimate, the Training Center still makes sense from an economic, business, and employee perspective as it is a long-term investment in furthering the technical skills, knowledge, and safety of not only the gas and electric field workers, but also of Liberty's employees as a whole. Such an investment also allows Liberty to better serve customer needs. As training requirements continue to increase and evolve, it is beneficial to have a facility that allows us to adapt to those changes and schedule new training as the need arises. Liberty is aware of other utilities that have invested $10 million and $20 million for gas training facilities whereas Liberty's facility services both gas and electric training requirements at a significantly lower cost.

Further, given the number of non-quantifiable benefits associated with the Training Center (see the Smith/Mullen DE 16-383 rebuttal testimony, the DG 17-048 Mullen testimony including Attachment SEM-1, and the responses to Staff 4-26, Staff 4-32, and Staff 5-40), a simple spreadsheet analysis would not provide a complete picture of this overall value. For instance, one benefit not mentioned in my testimony is that, effective in September 2017, the Training Center will serve as the backup contingency site for Liberty's call center. Using an existing facility that will be ready to serve contingency needs is sensible from both logistical and economic perspectives, particularly given that such contingency needs can and will occur unexpectedly.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests - Set 5

Date Request Received: 7/27/17 | Date of Response: 8/10/17
Request No. Staff 5-45 | Respondent: Steven Mullen

REQUEST:

Reference Docket DG 17-048, Response Staff 4-32. Does Liberty have any policy or guideline etc. related to using non-quantifiable costs or benefits in its decision making? Please explain in detail and provide any supporting documents.

RESPONSE:

Yes. Included in Liberty's "Capital Expenditures – Planning and Management" policy are templates for preparing a Business Case and a Capital Expenditure Application. Sections of each of those documents instruct the preparer to address non-quantifiable cost and benefit items:

- Alternatives – Pros, cons and risks;
- Qualitative factors;
- Risks and uncertainties including safety, economic, operational, technical, environmental, social/political, customer impact, and regulatory issues;
- Risks and consequences of not approving the expenditure;
- Health, safety, and security concerns and impacts; and
- Other pertinent details that may affect the decision making process.

The Business Case template includes the statement, "Not all decisions will be based on lowest cost – qualitative factors can drive the decision." Please see Attachment Staff 5-45.

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

DG 17-048
Distribution Service Rate Case

Staff Data Requests – Set 7

Date Request Received: 9/21/17
Request No. Staff 7-12

Date of Response: 10/5/17
Respondent: Steven Mullen

REQUEST:

Reference Staff 5-44 response: The response states "Cost increases were reviewed, analyzed, and approved as they arose." Please provide all analyses referenced in this statement.

RESPONSE:

The full relevant portion of the response to Staff 5-44 reads as follows:

> *As construction conditions for the Training Center changed, cost increases were analyzed based on change orders, information received from contractors, and other relevant documentation. Cost increases were reviewed, analyzed, and approved as they arose.*

"Analyze" means to study or examine an issue, but does not necessarily involve the preparation of documents or spreadsheet analyses. With respect to construction projects, analysis involves examining issues, changed conditions, and additional requirements as they arise to determine whether they are necessary, whether something can be done in another manner to address the changes, and the extent to which the new conditions will impact costs, schedule, and other considerations.

As discussed on Bates 015 and 016 of my June 30, 2017, prefiled testimony, many cost increases resulted from requirements imposed by the City of Concord and were not included in the original project cost estimate. Attachment Staff 7-12 is a copy of a document included in the project file that provides a narrative summary of the changes, and resulting cost increases, required by the City of Concord. (This information was previously provided to Liberty Consulting Group as Attachment PB-13.2.) Those requirements significantly increased the project costs and delayed the construction schedule.

In addition to the requirements of the City of Concord, many of the cost increases were fairly inconsequential, thus not warranting extensive analysis. For example, the installation of items such as a landline phone for security and safety contingencies, a manhole cover and guard that allows for manhole rescue training, and a roof hatch safety rail and grip tape on the stairs for added safety measures all are minor cost items that, while not included in the original pricing, were practical measures that required little analysis.

As stated in the response to Staff 5-44, analysis was performed by review of the change proposals, change orders, and supporting documentation for each cost increase. As with any major construction project, there were many changes to the costs of the Training Center project following the initial estimate; therefore, the Company suggests that Staff identify specific costs and the Company will provide the available supporting documentation.

Summarization of additional project costs imposed by City of Concord fees, inspection services, and scope of work changes.

In order to approve construction of the new Training Center and CNG facility on Broken Bridge Road in Concord, NH, the City of Concord (City) imposed certain required project conditions that added significant costs to the initial estimated costs of building the facilities. Due to the fact that the Training Center was being constructed first and in order to meet deadlines associated with completion of the Training Center, these costs were passed on to Training Center project. Specifically, the City required off-site improvements consisting of installation of a new municipal waterline and hydrants down the entire length of Broken Bridge Road, widening of certain sections of Broken Bridge Road, and complete resurfacing of the road. In order to be able to move forward with both projects, we moved forward with obtaining pricing to complete the off-site road improvements and added the costs to the Training Center contract ($488,905). Prior to the pre-construction conference with the City, the City notified us that traffic impact fees ($19,015), City inspection fees ($33,300), and water investment fee ($2,595) would need to be paid prior to the City giving approval to start work on-site. Due to schedule constraints these fees were paid and not contested through the City's appeal process. During installation of the waterline, unsuitable materials (organics) were encountered in the roadway within the waterline trench. The City required that these unsuitable materials be removed and replaced with imported structural fill including crushed stone below the waterline ($26,279). Due to the fact that the waterline was installed below the water table in certain areas and the placement of stone in the trench, water began seeping out of the road way in an area below a steep incline in the road. Due to the seepage, the City is requiring that an underdrain be installed ($15,073) in the section of roadway with seepage in order to direct water flow from below the road away from the road. An additional cost not associated with the roadway, but required by the City prior to receiving a temporary occupancy permit was the addition of a gas detection system within the building ($15,435). The gas detection was not included in the original plan set approved by the City, but the fire department required a gas detection system when they completed their final plan review for permit approval.

EXHIBIT
#14
DG 17-048

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Distribution Service Rate Case

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of the

STATE OF NEW HAMPSHIRE

OFFICE OF THE CONSUMER ADVOCATE

November 30, 2017

Table of Contents

Q. Would you please state your name and address?

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

Q. Please briefly describe your occupation and qualifications.

A. I am employed as a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation. I received a Bachelor of Arts degree in Economics from the University of South Florida, and both a Master of Science in Economics and Doctor of Philosophy in Economics from Florida State University.

Over the course of more than 40 years, I have been actively involved in more than 400 regulatory dockets, involving electric, natural gas, and other utilities. I have presented expert testimony on more than 250 occasions, before federal regulatory agencies, various state courts, and regulatory commissions in 40 states, two Canadian provinces, and the District of Columbia. Most of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation. However, our firm has also worked for other types of clients as well, including large industrial consumers and non-profit entities like the AARP and the North Carolina Sustainable Energy Association.

Q. Have you prepared an appendix that provides some additional details concerning your qualifications?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. I prepared Exhibit___(OCA-2), consisting of two schedules. These schedules were prepared under my supervision and are true and correct to the best of my knowledge.

Q. What is your purpose in making your appearance at this hearing?

A. My firm has been retained by the New Hampshire Office of the Consumer Advocate (OCA) to assist in preparing and presenting evidence with respect to the pricing and decoupling proposals submitted by Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberties Utilities ("EnergyNorth" or "the Company").

I will primarily be responding to the pricing proposals set forth in the testimony of David B. Simek and Gregg H. Therrien, and the revenue decoupling proposal set forth in separate testimony submitted by Gregg H. Therrien. I will also discuss the marginal cost study described in the testimony of Melissa F. Bartos, and the functional (embedded) cost study described in the testimony of David A. Heintz.

Following this introduction, my testimony has five major sections. In the first section, I discuss the Company's revenue decoupling proposal. In the second section I discuss the Company's proposed revenue allocation and rate design. I give particular attention to the EnergyNorth's proposals to increase the fixed monthly charges that are paid by all customers regardless of how much energy they consume. In the third section I define various economic concepts, including marginal costs, joint costs and sunk costs and the difference between the long-run and the short-run. I then explain how these concepts relate to the way prices are established in unregulated markets, and the rate design issues in this proceeding. In the fourth section, I discuss the Company's marginal cost study. I note some serious flaws in the study and recommend that the Commission not rely on the study results as submitted. In the fifth section I summarize my recommendations.

I. THE COMPANY'S DECOUPLING PROPOSAL

Q. Can you briefly describe the Company's decoupling proposal?

A. Yes. The Company is proposing a revenue per customer decoupling mechanism that will eliminate the traditional link between sales and revenues. Normally, when customers use more energy, revenues and earnings increase; when they use less energy, revenue and earnings decline. This normal linkage will be broken by creating a mechanism that periodically adjusts rates to cancel out the impact of usage changes.

> EnergyNorth proposes to implement rate design measures that will "decouple" the traditional connections between the volume of gas that EnergyNorth delivers to its customers and its revenues and earnings.[1]

If it is accepted by the Commission, this mechanism will disassociate EnergyNorth's financial performance from the amount of gas it delivers during any given month or year. This will tend to stabilize its revenues, improve earnings, and reduce the frequency rate cases. While these are significant benefits from a stockholder perspective, the Company did not dwell on these aspects of its proposal. Instead, its testimony primarily focuses on the way decoupling will reduce the disincentive for it to promote energy conservation.

> By eliminating the link between customer consumption and Company earnings, decoupling removes the disincentive

1 Direct Testimony of Gregg Therrien, Page 4.

> for utilities to promote conservation and energy efficiency programs. Companies that have implemented decoupling are no longer caught between promoting conservation (that reduce sales) and growing revenues (by increasing sales). Breaking the link between utility sales and revenues is the best way to promote conservation activities fully and freely.[2]

Q. Is decoupling related to the existing LRAM?

A. Yes. Decoupling would replace the LRAM, which serves a similar purpose. The LRAM was recently added to the Company's tariff pursuant to Order 25,932, which implemented the Energy Efficiency Resource Standard.[3] The parties to that proceeding sought to reduce the incentives utilities have to encourage increased energy usage, or to discourage energy conservation.

> Utilities should have the incentive and initiative to continue implementing robust energy efficiency programs effectively, to the mutual benefit of ratepayers, shareholders, and the natural environment of the state.[4]

Although the LRAM and decoupling were viewed as alternative mechanisms for achieving similar goals, full consideration of decoupling was postponed until future rate cases.

> [A] targeted lost revenue adjustment mechanism (LRAM) or decoupling may be used to compensate utilities for lost revenues associated with energy efficiency.
>
> …
>
> Because of Commission policy requiring the consideration of decoupling only within the context of a rate case, Staff recommended the adoption of an LRAM for the initial three-

2 Ibid, pp. 5-6.
3 New Hampshire Public Utilities Commission, Order 25,932, August 2, 2016 (“Order 25,932”).
4 Ibit, p. 9.

> year period, to be replaced thereafter by a decoupling mechanism.[5]

Q. How does decoupling relate to energy conservation?

A. Under traditional ratemaking, utilities benefit when customers use more energy, since this leads to increased revenue in the short-run and a larger rate base and increased earnings in the long-run. The LRAM alleviates these perverse incentives, but only with respect to specific energy efficiency programs and initiatives. Decoupling achieves a broader, more fundamental shift in incentives, because revenues become largely impervious to improvements in energy efficiency – including improvements resulting from tightened building codes, increased appliance standards, technology improvements, heightened awareness of greenhouse gas emissions, and other factors.

This broader scope is significant, because EnergyNorth can potentially influence the decisions by customers and the companies that construct new buildings concerning what insulation they install, what appliances they purchase, and what type of energy they use. Currently, EnergyNorth has an incentive to steer customers into the programs and initiatives included in the LRAM, rather than finding other ways to reduce their energy usage that are not tied to those specific programs.

Implementation of decoupling is often accompanied by a move away from high fixed customer charges, declining blocks, and other rate structures that create a

5 Ibid, p. 24.

disincentive for energy conservation.[6] For example, Pacific Gas & Electric (PG&E)'s move to decoupling included replacement of their fixed customer charge with a minimum monthly charge of three dollars. This makes sense, because decoupling provides the revenue stability that was one of the primary motivations behind high fixed customer charges and low volumetric rates, but without the harmful impacts on low usage customers and without the disincentive for energy conservation associated with high fixed charges and low volumetric rates.[7]

Q. How does decoupling affect customers?

A. As with the LRAM, the per-therm cost of gas delivery will increase under decoupling – assuming conservation efforts are resulting in a downtrend in energy usage per customer. However, decoupling is more symmetrical than the LRAM. For instance, if commercial and industrial usage increases due to an improvement in economic activity, the decoupling mechanism can lead to lower rates – a potential that does not exist with the LRAM.

When thinking about these issues, it is important to remember that distribution rate increases that occur under decoupling would eventually occur anyway, under

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[6] Lazar, J. and Weston, F. Regulatory Assistance Project. Revenue Decoupling: A Guide to Theory and Application. Page 25-28. (June 2011) Available at: https://www.raponline.org/wp-content/uploads/2016/05/rap-revenueregulationanddecoupling-2011-04.pdf

[7] Migden-Ostrander, J. and Sedano, R. Regulatory Assistance Project. "*Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*." Page 39. (November 2016) Available at: http://www.raponline.org/wp-content/uploads/2016/11/rap-sedano-migdenostrander-decoupling-design-customizing-revenue-regulation-state-priorities-2016-november.pdf (Stating "high fixed charges reduce the customer's incentive to conserve by increasing the payback period on energy efficiency and distributed generation investments" and "there is significant concern around the perverse subsidy that high fixed charges create in which a customer living in a large suburban home pays the same high monthly fixed charge as a low-income customer in a one bedroom or studio apartment, even though the costs for the utility to serve these customers are dramatically different in that the cost to serve customers in densely populated areas is generally less than in more spread-out residential neighborhoods."

traditional ratemaking, but with different timing. Regardless of whether or not decoupling is adopted, customers who reduce their energy usage will receive the benefit of a lower bill, and customers as a whole must still pay the fixed costs of the delivery system. The main difference is that rate adjustments necessitated by improved energy efficiency will occur in smaller, more frequent increments under decoupling.

That is not to say the only possible difference is one of timing. Under traditional ratemaking (without an LRAM or decoupling), customers can potentially benefit from the lag between the time when energy usage is reduced and when rates are adjusted. However, there are no “free lunches” under traditional rate base regulation. The more significant the improvement in energy efficiency, the more this lag will result in downward pressure on the utility's earnings. The resulting earnings erosion or attrition will motivate the utility to file more frequent rate cases, and it is likely to request a higher allowed return, larger allowances for “known and measurable changes,” larger step increases, or other modifications to the traditional ratemaking process, in an effort to offset the earnings erosion problem. Regardless of whether or not these requests are accepted, the Commission will take steps to ensure that the Company has a reasonable opportunity to recover its costs and earn a fair return. And, regardless of the outcome, the increased frequency and complexity of the rate filings will increase rate case expenses – to the detriment of customers.

Q. Is the proposed decoupling mechanism an improvement over the existing LRAM?

A. Yes. It does a better job of removing the disincentive for EnergyNorth to encourage energy conservation, while eliminating the bias in favor of programs and initiatives included in the LRAM. With decoupling, the Company will have a more neutral outlook, since it will no longer be financially better off when customers channel their energy conservation efforts into specific programs included in the LRAM.

The proposed decoupling mechanism is also superior to the LRAM because it is symmetrical, while the LRAM is not. This means the potential exists for rate reductions due to decoupling – or, at a minimum, offsetting factors can potentially ameliorate the magnitude of rate increases necessitated by energy conservation. Decoupling allows revenue increases attributable to factors like changes in economic conditions and changes in the customer mix to offset revenue reductions attributable to energy efficiency programs. In contrast, the LRAM is narrowly focused on the impact of energy reductions due to specific programs, so there is no opportunity for offsetting factors to be considered.

Q. Please compare the approximate cost to ratepayers of EnergyNorth's LRAM arrangement against the approximate cost of the proposed decoupling mechanism.

A. Under the arrangement set forth in the April 2016 EERS Settlement Agreement and approved in Order No. 26,932, New Hampshire's investor owned utilities are compensated for their lost revenues attributable to their energy efficiency programs on a cumulative basis, with lost revenues accruing until the Company's next rate case, at which point the lost revenues are "reset to zero." *Order No. 26,932* at 30. The projected compensation associated with EnergyNorth's LRAM detailed in the 2016 EERS Settlement Agreement's "Gas Attachment B" assumes a four year timeframe before

EnergyNorth's first "reset to zero," and is summarized in the table on the left.[8] This can be compared to the approximate cost to ratepayers of the proposed decoupling mechanism. An estimate of that cost is provided by Greg Therrien for the period from summer 2011 to summer 2016 and summarized in the table to the right.[9]

Year	EnergyNorth Lost Base Revenue
2017	$143,274
2018	$480,808
2019	$841,813
2020	$1,226,837
Annual Average	**$673,183**

Year	Accrued Revenue Shortfall (Surplus)
Summer 2011	$224,260
Winter 2011-12	$3,969,815
Summer 2012	$446,708
Winter 2012-13	$156,006
Summer 2013	$162,960
Winter 2013-14	($3,479,131)
Summer 2014	($325,587)
Winter 2014-15	($2,761,837)
Summer 2015	($60,719)
Winter 2015-16	$3,687,185
Summer 2016	$85,642
Annual Average	**$382,781**

Q. Are there changes to the proposed decoupling mechanism that should be considered?

A. Yes. The Commission should consider two changes: linking the decoupling mechanism to total revenues, rather than revenue per customer, and having the mechanism operate on a "real-time" basis.

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[8] Energy Efficiency Resource Standard Settlement Agreement. Gas Attachment B. Page 4 of 7. Available at: http://www.puc.state.nh.us/Regulatory/Docketbk/2015/15-137/LETTERS-MEMOS-TARIFFS/15-137_2016-04-27_STAFF_PARTIES_ATT_SETTLEMENT_AGREEMENT.PDF

[9] Therrien Direct Testimony at Bates 327. (Annual Average is the sum of the revenue column figures, divided by 5.5 years)

Q. Can you briefly elaborate on the difference between total revenue decoupling and revenue per-customer decoupling?

A. The key difference is whether revenues are pegged to the dollar amount needed to recover the revenue requirement, or whether that amount is converted into a per-customer equivalent. Under the latter option, total revenues will increase over time, as customers are added to the system. The Company explained its preference for the per-customer approach as follows:

> Adding new customers to the system involves incremental capital investment, which requires that the revenues from these new customers be necessarily retained by the Company to fund this new investment. Therefore, RPC RDMs are superior to Total Revenue RDMs for gas utilities, as new customer revenues are retained (at the system average RPC) to help cover the cost of the corresponding new investment. If a Total Revenue RDM is employed instead, then the LDCs incentive to add new customers is significantly diminished, as total revenues will remain unchanged while rate base grows.[10]

While I understand this reasoning, I don't find it persuasive. Total revenue decoupling would stabilize the Company's revenues at a level that has been reviewed and approved by the Commission, equal to the approved revenue requirement. In contrast, the per-customer approach results in a growing level of revenues (tied to the number of customers), which will become increasingly attenuated from the revenue requirement that was calculated and approved by the Commission in the most recent rate case.[11]

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[10] Direct Testimony of Gregg Therrien, Page 11.

[11] If the Commission chooses to rule in favor of the Company's revenue per customer proposal, they should consider requiring rate cases at least every five years, to ensure the gap between approved revenues and required revenues does not become excessive.

The increase in revenues that occurs with per-customer decoupling is not necessarily matched by an equivalent increase in the revenue requirement. In fact, some customers can be added to the system at locations where very little additional capital investment is required. There is no assurance that the increase in total revenues that occurs under the per-customer approach is fully needed, or that the resulting revenue growth will match any corresponding increase in the revenue requirement. It is also important to keep in mind that EnergyNorth has cash flows provided by depreciation and retained earnings that can be used to support new customer additions. If its capital additions exceed depreciation, and as a result its rate base increases (rather than decreases as depreciation accumulates), it will have the opportunity to recover the associated costs after they are reviewed and approved in a rate case.

As to the question of incentives, it is true that total revenue decoupling reduces the incentive to add new customers, but it will not completely eliminate that incentive. From a utility's perspective, growth is almost always viewed as desirable – particularly if it translates into an increase in the rate base. Growth in rate base supports growth in earnings per share and it makes a utility's stock more attractive from a stockholder perspective. There is every reason to anticipate that EnergyNorth will continue to pursue growth opportunities even if decoupling is approved on a total revenue basis. Admittedly, customer growth will not be as profitable as it would be under per-customer decoupling, but that does not mean growth will suddenly become unattractive, or negate the appeal of a larger rate base and increased overall scale of the Company's operations.

Q. Are there benefits to using total revenues rather than revenues per-customer?

A. Yes. This approach further increases revenue stability, which is appropriate since the Company's cost structure is tied to extremely long-lived investment. This approach also makes it easier to visualize and anticipate the impact of the decoupling mechanism – eliminating uncertainties related to unknown future fluctuations in the number of customers, the mix of different types of customers (e.g. high versus low-load factor commercial and industrial customers), and the impact of changing economic conditions on the usage of different size customers.

Q. Can total revenue decoupling be implemented in a way that provides additional funding for customer growth?

A. Yes. If the Commission decides that expansion into new areas should be encouraged and this type of customer growth should be more strongly supported, revenues from new customers that pay the "expansion rate" can be excluded from the total revenue decoupling mechanism. For instance, revenues from new customers who are required to pay the R-6 (Residential Heating-Expansion) delivery rates (which are 30 percent higher than existing R-3 Residential heating rates) could be excluded from both the "actual" and "target" revenues considered in the decoupling mechanism. This would effectively allow the Company to retain revenues from this category of customers, but not from new customers connected to parts of the system where the expansion rates do not apply.

Q. What do you mean by a "real-time" approach to decoupling?

A. Under the Company's proposal, annual calculations are performed that take into account the difference between actual billed revenues and the target level of revenues approved by the Commission. In a typical year, a large portion of this difference will be attributable to weather fluctuations; the remainder is attributable to energy conservation and other factors that influence usage.

> Between rate cases, sales vary because of weather, conservation, economic conditions, the deployment of DERs, and other factors. But weather is probably the largest of these, responsible for perhaps 80 percent of decoupling cost deferrals.[12]

With "real-time" decoupling, the difference between actual and normal weather is calculated and used to adjust bills as they are sent out each month.[13] This essentially eliminates any impact of weather on the annual decoupling calculations, confining those calculations to the more limited purpose of adjusting for any remaining difference between billed revenue and the targeted level of revenue. In effect, weather related usage fluctuations are decoupled in "real-time" each month, while all remaining usage fluctuations – including the downtrend in usage due to increased energy efficiency – are decoupled in the annual adjustment process.

Real-time decoupling can be implemented using either a per-customer or total revenue approach. In the former case, the review process would adjust for any

[12] Migden-Ostrander, J. and Sedano, R. Regulatory Assistance Project. "Decoupling Design: Customizing Revenue Regulation to Your State's Priorities." Page 25. (November 2016) Available at: http://www.raponline.org/wp-content/uploads/2016/11/rap-sedano-migdenostrander-decoupling-design-customizing-revenue-regulation-state-priorities-2016-november.pdf
[13] Ibid.

discrepancies between billed revenues and the authorized level of revenues per-customer. In the latter case, the review process would adjust for any discrepancies between total billed revenues and authorized total revenues. Because the review process would not be focused on weather fluctuations, it could occur annually (rather than semi-annually, as proposed by the Company).

Q. Are there benefits to "real-time" decoupling?

A. Yes. This type of decoupling would achieve the same degree of revenue stability, while improving cash flow stability. This is a significant benefit for both the Company and its customers. Because weather-related decoupling would occur within the billing cycle, it will help smooth out bill fluctuations, making cash flows smoother and more predictable for both the Company and its customers.

Consider, for example, what would happen if November 2018 were unusually cold (compared to a normal November). Under EnergyNorth's proposal, this will result in a downward rate adjustment in order to achieve a stable level of revenues per customer – but the rate reduction won't occur until the 2019-2020 winter season – roughly a year after the cold snap. Under EnergyNorth's proposal, the offsetting bill credit appears a year later – far too late to help alleviate any cash flow problems customers suffer in the immediate aftermath of unexpectedly cold weather.

If a real-time decoupling mechanism were used instead, the rate reduction would be calculated and applied to the same billing cycle that includes the higher usage, and the downward rate adjustment or bill credit would appear in the exact same bill that includes the higher usage due to the abnormally cold weather. This is a very significant timing difference, which provides a very real, tangible benefit for customers – weather-related downward bill adjustments occur precisely when they are most needed.

If weather is abnormally mild, the corresponding bill adjustment works in reverse. With real-time decoupling, an upward adjustment occurs on the exact same bill that has a lower than expected level of usage. This timing is again ideal, because customers will be paying the slightly higher rate during a month when their usage is lower than normal. The end result is a slightly higher bill than if decoupling were not in effect, but that bill is still lower than it would have been if the weather had been normal. In contrast, under EnergyNorth's proposal, the upward rate adjustment appears on bills roughly a year later – at a time when the customer's bill might actually be higher than normal, due to colder than normal weather.

Not only does the “real-time” approach improve cash flows from the customer's perspective, it also improves cash flows from the Company's perspective. Since the Company's cost structure is largely fixed, while the weather fluctuates widely, this discrepancy forces it to maintain larger cash balances, or to engage in more intensive cash management efforts, than if its cash inflows were following a stable, easily predicted seasonal pattern based upon normal weather.

EnergyNorth's decoupling proposal does not improve this situation. Although it stabilizes revenues, it accomplishes this by accruing a “normal” level of revenues for each month; its actual incoming cash flow will not be synchronized with this stabilized revenue accrual. If the weather is mild, the Company will bill less than it accrues, then wait a year to implement the rate adjustment needed to actually receive the cash corresponding to its accrual. Conversely, if the weather is unusually cold, the Company will bill more than it accrues, keeping the excess cash until it adjusts rates downward approximately a year later. Weather fluctuations in both directions will continue to cause fluctuations in customer bills, and corresponding fluctuations in cash received from customers, which will not be synchronized to the Company's actual (relatively stable) cash flow needs.

In contrast, with real-time decoupling, cash flows will be synchronized with a stabilized, seasonal revenue pattern (customers will continue to see lower bills in the summer and higher bills in the winter, consistent with normal seasonal weather patterns). The timing of cash flows will be more predictable and improved for both the Company and its customers, regardless of how warm or how cold it is. With either approach to decoupling, rates will eventually be reduced if the weather is unusually cold, and they will eventually increase if the weather is unusually mild. The key difference is when this occurs. With the Company's proposed approach, weather-related rate adjustments occur long after an unusual weather event occurs, so the Company has to deal with the cash flow discrepancy during the interim. In contrast, with real-time decoupling, rate adjustments are simultaneous with weather-related usage fluctuations, thereby mitigating bill fluctuations and reducing the need to deal with cash flow discrepancies.

Since a real-time decoupling mechanism would provide substantial benefits to EnergyNorth, it would be reasonable for the Company to accept responsibility for most, if not all, of the administrative costs necessary to initiate this form of decoupling.[14]

[14] A preliminary vendor estimate provided to EnergyNorth and conveyed to the OCA via email on 11/27/17 suggests the up-front administrative costs associated with billing system upgrades is in the vicinity of $50,000 to $100,000. Amortized over three years, the mid-point of this estimate is equivalent to .015 cents per therm. To put this into

Q. Are there any other advantages to the "real-time" decoupling approach?

A. Yes. Customers will be more likely to understand and accept the mechanism if the portion that deals with weather-related fluctuations is separated from the portion that deals with energy conservation and other factors influencing usage. With the Company's proposal, weather-related rate adjustments will be combined with calculations related to other changes in usage, making it more difficult to explain the process to customers. Since weather fluctuations are very noticeable to customers, it makes sense to show them the weather-related rate adjustment immediately after the weather event – rather than a year later. Without the impact of weather fluctuations, the annual rate adjustment will be smaller, and it will be easier to explain to customers.

With the "real-time" approach, the annual true-up will compare billed revenues to authorized revenues. The resulting adjustment will ensure that actual revenues match the authorized level (either defined as the Commission-authorized total revenue or the authorized revenue per customer multiplied by the total number of customers). That annual discrepancy will be relatively small, since it won't be affected by weather fluctuations, and given its narrow focus it can be more readily explained as an "adjustment to match authorized revenues." Since the annual rate adjustment will be smaller under real-time decoupling, this approach also alleviates the need to impose a customer impact cap as suggested in Greg Therrien's Direct Testimony at Bates 324. If the Commission were to rule against real-time decoupling, they should strongly consider adoption of the customer impact protections suggested by Mr. Therrien. Additionally, since the magnitude of the annual adjustments will be smaller, and symmetrical, it would

perspective, this is equivalent to 1 cent per month for a residential or small commercial customer using 800 therms per year.

be reasonable to further simplify the calculations by eliminating the need for a carrying charge associated with deferrals between true-up periods.

Q. Does real time decoupling shift risks associated with weather-related revenue fluctuations away from the Company toward customers?

A. No. With real-time decoupling risks are reduced for <u>both</u> stockholders and customers. Unexpected month-to-month and year-to-year fluctuations in customer cash-flows will diminish for customers just as they will diminish for stockholders – delivery bills will follow a predictable pattern that tracks normal seasonal patterns. For both sides of the billing process, real time decoupling eliminates the consequence of having a day or month that happens to be warmer or colder than that day or month would normally be. Removing this weather-related risk benefits both stockholders and customers.

Q. Do you have any other comments related to weather fluctuations?

A. Yes. New Hampshire has recently been experiencing mild winter weather, compared to years past, as shown below:

	Oct -Nov	Dec - Feb	Mar - May	Jun - Sep	Total
40 Yr	1,131	3,360	1,627	196	6,314
30 Yr	1,122	3,329	1,64o	183	6,273
25 Yr	1,127	3,327	1,646	173	6,272
20 Yr	1,124	3,317	1,642	174	6,257
15 Yr	1,119	3,345	1,624	166	6,254

	Oct -Nov	Dec - Feb	Mar - May	Jun - Sep	Total
10 Yr	1,111	3,338	1,578	166	6,193
5 Yr	1,103	3,276	1,576	158	6,112

It is not self-evident whether the recently milder weather has been entirely due to a sustained long term downward trend, or if cyclical factors or random fluctuations have been contributing factors. Regardless, the recent trend is not likely to suddenly reverse, or immediately revert to the colder weather that was experienced decades earlier. Given the above data, for ratemaking purposes, it would be reasonable to use a slightly shorter period of 25 years, and to give more weight to recent data than to older data. More specifically, I recommend giving full weight to the 2016 data, 24/25 weight to the 2015 data, 23/25 weight to the 2014 data, and continuing with that pattern through 1992, which should be given 1/25 weight. The resulting 25 year weighted averages are shown below:

	Oct -Nov	Dec - Feb	Mar - May	Jun - Sep	Total
25 Yr	1,114	3,327	1,623	168	6,233

Q. What would be the effect of this change?

A. It would have no impact on the calculated revenue requirement, but it would reduce the test year billing units. In turn, this would increase the calculated volumetric rates needed to achieve the revenue requirement. Finally, this change would make it more likely for the weather-related portion of any approved decoupling adjustments to fluctuate back and forth between positive and negative amounts, rather than being consistently biased in the positive direction. Stated another way, if decoupling is tied to "normal" weather that is colder than the milder weather that will actually be experienced during the next five to ten years, the decoupling adjustment will be systematically biased in the upward direction. This problem can be mitigated by using "normal" weather data that is more consistent with recent experience.

Q. Can you please summarize your recommendations concerning decoupling?

A. I recommend the Commission adopt a total revenue decoupling mechanism, in lieu of the existing LRAM. To the extent it is practical to do so, I recommend implementing this mechanism on a real-time basis, in conjunction with 25 year weighted average normal weather data for each billing cycle.

II. THE COMPANY'S RATE DESIGN PROPOSALS

Q. Before delving into the details of the Companies' pricing proposals, can you briefly explain your general approach to rate design?

A. Yes. Although rate design is more of an art than a science, it is nevertheless a very important part of the overall regulatory process. Designing rates is the stage where the Commission's decisions will have the greatest short-run impact on customers, and the greatest long-run impact on the Commission's overall policy goals. Rate design is not an area where deference should be given to the utility's preferences, or where "business as usual" is an appropriate philosophy. Instead, this is an area where the Commission should carefully weigh the pros and cons of the available options, and adopt that set of rates which it concludes will best serve the public interest.

The following discussion (in the context of electric rates) from page 5 of the Smart Rate Design for a Smart Future issued by the Regulatory Assistance Project in July 2015 is informative:

> Rate design is important because the structure of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other . . . market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.

Before going into greater detail concerning the current and proposed rate design, it is worth noting that the Commission faces a difficult task in designing rates, and I fully understand it must weigh the claims made by parties with widely varying perspectives. The Regulatory Assistance Project provides some useful perspective concerning the rate design process on page 8 of their July 2015 paper, Smart Rate Design for a Smart Future:

> A variety of stakeholder interests are at play in the debate over rate design, and finding common ground is not easy. Regulators face the task of fairly balancing concerns among utilities, consumers and their advocates, industry interests, unregulated power plant owners, and societal interests. The

> regulator accepting the charge of "regulating in the public interest" considers all of these values.

It is for this reason that I will explain my recommendations in considerable detail. EnergyNorth's revenue allocation and rate design proposals are closely linked to its marginal cost study, so I will define various cost-related terms and provide a strong theoretical foundation for my critique of the Company's cost claims.

There is one overarching theme that will run through all of this discussion: the appropriate relationship between prices and costs, and how that relationship impacts different types and sizes of customers. To advance the public interest, and be more consistent with how prices are set in competitive markets, I recommend recovering more of the revenue requirement through the volumetric rates. Throughout the remainder of my testimony I will provide detailed evidence supporting this recommendation, with the intent of providing the Commission with the tools it will need to evaluate the claims made by EnergyNorth and to chart a course that makes greater progress toward well-accepted public policy goals, without unduly impacting any group of customers.

A. Fixed versus Volumetric Cost Recovery

Q. What has EnergyNorth proposed with respect to its rate design?

A. The Company made a priority to increase its customer charges (the fixed monthly rate that applies regardless of how much or how little gas the customer uses). This priority is apparent from the workpapers it used to develop the proposed rate design, and is alluded to on pages 16-17 of the joint testimony of Simek and Therrien. They describe a two-step process: the proposed customer charges were developed first, and the remainder of the revenue requirement was recovered through the volumetric rates. The Company's marginal cost estimates were used in both steps.

> To determine the appropriate level of customer charges for each class, we considered: (1) the marginal customer costs resulting from the marginal cost study; (2) rate continuity; and (3) customer impacts.[15]

The second and third items just mentioned did not support increasing the customer charges; rather, they ameliorated the extremely large increases that would be needed to move these rates all the way to the Company's estimate of marginal cost. For example, the Company is proposing to increase the customer charge for the residential R-1 (non-heating) class by $6.23, or 40.8%, from the current tariff level of $15.27 to the proposed level of $21.50. The marginal cost calculated by the Company for this class is $61.17. They would have needed to increase this rate element by 300% – from $15.27 to $61.17 – in order to go all the way to the cost they calculated. Needless to say, such an extreme increase in this rate element would not be consistent with the principle of rate continuity, and the resulting customer impacts would also be of potential concern – hence the reference to the second and third factors they considered in deciding on the proposed customer charges.

Q. What has the Company proposed for other customer classes?

A. For the other residential tariffs it used a similar approach, increasing the customer charge to a level that moves closer to the numbers calculated in its marginal cost study, then adjusting the remaining (volumetric) rate elements as necessary to achieve the requested

15 Direct testimony of Simek and Therrien, Page 17.

revenue requirement. The primary thrust of this exercise was to move customer charges closer to the cost level calculated by the Company. However, it ameliorated that movement in the interest of maintaining a degree of rate continuity and to avoid excessive customer bill impacts.

Since the proposed rate design is closely tied to the Company's marginal cost results, I will discuss the appropriate relationship between costs and prices in the next major section, followed by my discussion of the Company's marginal cost study. I would note, however, that EnergyNorth's primary focus seems to be on increasing the customer charges; the cost study is in more of a supporting role. One reason I say that is because the Company is proposing increases to its customer charges even for tariffs where moving in that direction isn't supported by its cost study. This is apparent from this passage in its testimony:

> Although Attachment RATES-5 Line 99 also indicates that the proposed C&I rate class customer charges exceed the marginal unit customer costs for rates G-42, G-43, G-52, and G-53, the customer charges for these rate classes were increased by 10 percent,

The Company could have proposed maintaining the existing customer charges, or begun to move them toward the (lower) calculated marginal cost level. The Company instead proposed to increase the customer charges by 10% – which is about five times the recent annual rate of inflation. No cost justification was offered to support this proposal, nor was there any acknowledgement that this would exacerbate and perpetuate an existing pattern of overcharging low use customers (according to its own cost calculations). The stated reason supporting this proposal is that the 10% increase was necessary to ensure a large enough share of the rate increase would be paid by low usage customers relative to larger customers in the same class:

> if we had not increased these rate class customer charges, large gas users in each of these classes would experience disproportionately large increases, relative to smaller gas users in each of these rate classes.

While applying a similar percentage increase to both small and large customers may seem reasonable, what is notable is that this reasoning was <u>not</u> followed in the opposite direction. Nor was it followed with respect to the prices charged to customers in the Keene division.

If it had consistently applied this line of reasoning, the Company could have concluded that large users in the Keene division should pay 10% higher rates, rather than decreased, to ensure that other customers do not experience disproportionately large increases. Similarly, if it had following this reasoning consistently, it would have concluded that residential customer charges should not be drastically increased, because a disproportional increase to this rate element has the effect of requiring small residential gas users to experience disproportionately large increases, relative to larger gas users in the same rate class. In other words, the emphasis on maintaining existing rate relationships seems to be somewhat selective in EnergyNorth's proposals. The one thing that seems to consistently run throughout the Company's rate proposals (as well as its decoupling proposal) is a desire for greater revenue stability, which would be achieved by imposing higher customer charges.

Q. Do you agree with this emphasis on increasing customer charges?

A. No. The public interest can best be advanced by moving in the opposite direction. A gradual process may be more appropriate than immediately implementing the reductions in customer charges that could be justified based on the evidence in this case, but it would be appropriate to at least begin to move that direction. By decreasing the fixed part of the bill and increasing the volumetric part (increasing the per-therm rate – particularly in the tail block), the Commission can provide a stronger incentive for customers to fully participate in controlling their utility bill, and a stronger incentive to learn about and adopt more energy efficient products and technologies. By moving in the opposite direction to that proposed by EnergyNorth, the Commission can reduce the burden on small customers, thereby making the tariff structure more equitable, it can enable customers to gain greater control over their monthly utility bill, and it can advance the broad public interest by encouraging energy efficiency.

EnergyNorth's current rate structure does not provide a very strong incentive for customers to increase the insulation in their home or business, or to replace existing, inefficient water heaters and furnaces with more energy efficient ones. Reasonable steps can and should be taken in this proceeding to strengthen these incentives by increasing the volumetric rates, and especially the tail block rates. These steps will also have the salutary effect of reducing the burden on low energy users and providing all customers with an increased opportunity to gain control over their utility bill.

B. Comparison to Other Utilities' Rates

Q. How do the Company's existing and proposed customer charges compare to those in other jurisdictions?

A. With the exception of the rates paid by customers in the Keene division, EnergyNorth's customer charges are already higher than those charged by many other utilities in New England and elsewhere around the country. In May 2015, the American Gas Association published a report that concluded that the nationwide median residential customer charge was just $11.25 per month, while the customer charge in EnergyNorth's R-1 (residential non-heating) tariff is currently $15.27. It's R-3 (residential heating) tariff includes a customer charge of $22.10, which is nearly double the nationwide median reported by the American Gas Association. A substantial discrepancy also exists in the Company's other tariffs. For instance, the nationwide median rate for commercial customers was reported to be $22 per month, which is less than half the Company's current customer charge of $48.36 for G-41 and G51 (commercial/industrial – low annual use) customers. The discrepancy is even more extreme for the Company's G-42 (commercial/industrial – medium annual use) customers, who are currently paying a fixed monthly rate of $145.08 in addition to the volumetric rate.

Table 2
2015 Natural Gas Utility Median Monthly Customer Charges by Census Region

Census Region	Residential	Commercial
New England	$ 13.50	$ 28.41
Middle Atlantic	$ 14.60	$ 23.60
East North Central	$ 11.38	$ 24.00
West North Central	$ 13.16	$ 24.40
South Atlantic	$ 10.00	$ 22.00
East South Central	$ 14.00	$ 16.96
West South Central	$ 13.24	$ 18.51
Mountain	$ 10.80	$ 20.00
Pacific	$ 4.95	$ 14.90

As shown in the table above, the data in the American Gas Association report suggest that EnergyNorth's New Hampshire customers may already be paying some of the highest customer charges in the United Sates. Further increasing these charges may seem appealing to the Company, since this would further increase the stability of its revenues. However, the current high customer charges already impose a large burden on low usage customers compared to the rates charged by many other utilities. Furthermore, the higher the customer charge, the lower the volumetric rate. Tilting the balance away from volumetric rates detracts from the widely accepted public policy goal of encouraging energy conservation.

C. Fixed Cost Recovery

Q. Gas utilities sometimes argue that a fixed monthly fee is the correct way to recover costs that are fixed. How do you respond to this argument?

A. I am willing to concede there is some intuitive appeal to this argument. However, it is at most a pricing tactic rather than a valid goal – the actual goal is revenue predictability or stability. This goal makes sense from a utility's perspective, but it is not a high priority from a public interest perspective. Nor is there any policy reason why fixed costs need to be recovered through fixed rates. A stable, more predictable revenue stream makes it easier to manage a firm's cash flows, and it could might reduce the risks borne by the firm's stockholders to a small degree, but neither of these concerns merit much weight from a public policy perspective.

In fact, this pricing tactic does not advance the public interest, since it conflicts other, more significant policy goals, like inter-customer equity and encouraging energy conservation. Moreover, recovering fixed costs as a uniform amount per customer is not consistent with the fixed cost recovery mechanism that is typical of most unregulated markets. In competitive markets the interaction of supply and demand determines prices, and there is no consistent tendency for fixed costs to be recovered through “fixed charges” nor is there any tendency to charge every customer the same amount each month, regardless of how much or how little they use.

Where substantial fixed, sunk and joint costs exist, the portion of these costs that is recovered from different products or services will not be a uniform amount each month, but instead will vary depending upon supply and demand conditions. More specifically, the relative cost-recovery shares will depend on the degree to which different types of purchasers benefit from the production process, and the relative strength of demand for the different products that are being jointly produced. Each customer will not contribute a uniform, fixed dollar amount toward the recovery of joint and common costs merely because those costs are fixed. To the contrary, cost recovery will vary widely, with larger customers tending to contribute more than smaller customers (because they use more, and benefit more from the common production process). Similarly, if some of the products offered by the firm are perceived to be more valuable than others, those will tend to have a larger markup, resulting in a larger contribution toward joint and common costs than is obtained from those products that are perceived to be less valuable.

In most parts of the economy, the amount contributed by specific customers, or specific products will vary depending on the strength of demand. The stronger the demand – and in that sense, the greater the benefit received from joint and common production processes – the greater the share of joint and common costs that will be borne by any particular product, service, customer, or customer group.

Q. EnergyNorth's rates are determined by the Commission, not by market forces. Should the Commission deviate from the normal market outcome to require uniform per-customer contributions toward fixed costs?

A. No. Just because the Commission has the option of doing this doesn't make it preferable. In fact, the advantages of non-uniform cost recovery can be demonstrated by looking at a different analogy: how taxing authorities most frequently handle the problem of spreading the tax burden (recovering the fixed costs of providing government services).

Consider a hypothetical small business owner who operates a 1,000 square foot retail store. This retailer competes with several other retailers located on the same side of the street, which are twice as large, as well as a 50,000 square foot department store located across the street. Under the cost recovery approach advocated by the Company, the department store would contribute the same amount toward the local municipality's fixed costs as the smallest competitor on the street, despite being 50 times larger.

It is certainly true that many of the costs of providing government services (like the cost of maintaining a traffic light at the end of the street where all of the stores are located) are fixed, at least in the sense they do not directly vary with the size of each store. Nevertheless, few people would argue it would be more equitable to require the smallest store on the block to pay the same dollar amount per month toward the municipality's fixed costs as the largest store on the block, merely because the costs are the same every month, and cannot be directly attributed to any one store. The inequitable nature of a uniform, “everyone pays the same amount” approach to cost recovery becomes even clearer when their respective shares of the fixed costs are compared on an apples-to-apples basis. The department store would end up paying 98% less per square foot for the municipality's fixed costs than the smallest store. Similarly, other stores on the the street would pay half as much per square foot as the smallest store. Most people will readily concur that this would not be a fair approach to cost recovery.

Q. Does similar reasoning apply to the recovery of fixed costs from different size residences?

A. Yes. If the fixed costs of government were going to be collected as a uniform dollar amount from all residences, both small and large, a hypothetical 400 square foot studio apartment would pay as much as a luxurious 3,500 square foot house – even though many of the municipal services (like maintaining 24-hour per day police and fire protection) provide greater benefits to the owner of the larger, more costly residence. In practice, by collecting property taxes in proportion to assessed value, an attempt is made to ensure that all types and sizes of residences make a reasonable contribution toward the fixed costs of providing government services – and that contribution is not a uniform monthly dollar amount. Instead, the amount contributed through taxes varies widely, with large residences generally contributing more than small residences.

Q. What conclusion do you draw from this analogy?

A. First, this analogy demonstrates that the rate design I am recommending is consistent with the cost recovery pattern that is most frequently observed when government policy makers, tasked with serving the public interest, decide how best to recover the fixed costs of government.

Second, this analogy helps demonstrate the inherent fairness of a non-uniform cost recovery pattern. Taxes provide an example where non-uniform cost recovery is familiar and a pattern that most of us readily accept without dispute. In fact, it is hard to imagine anyone arguing that the smallest store on the block (or its landlord) should pay the exact same dollar amount in property taxes as the largest store. Over the course of many years, involving many different public policy decision-makers in many different jurisdictions, it has been the common practice to spread the tax burden widely but not uniformly. Virtually all local, state and federal taxes are recovered from households and businesses in ways that ensure that small taxpayers pay much less than large ones. The largest taxpayers, who are in the strongest position to pay for government services, pay the lion's share of the tax burden. This pattern of cost recovery is widely accepted because it spreads the cost of government more equitably than a system that requires every taxpayer to pay the same dollar amount. In the next section I will demonstrate that non-uniform fixed cost recovery is also prevalent in most unregulated markets.

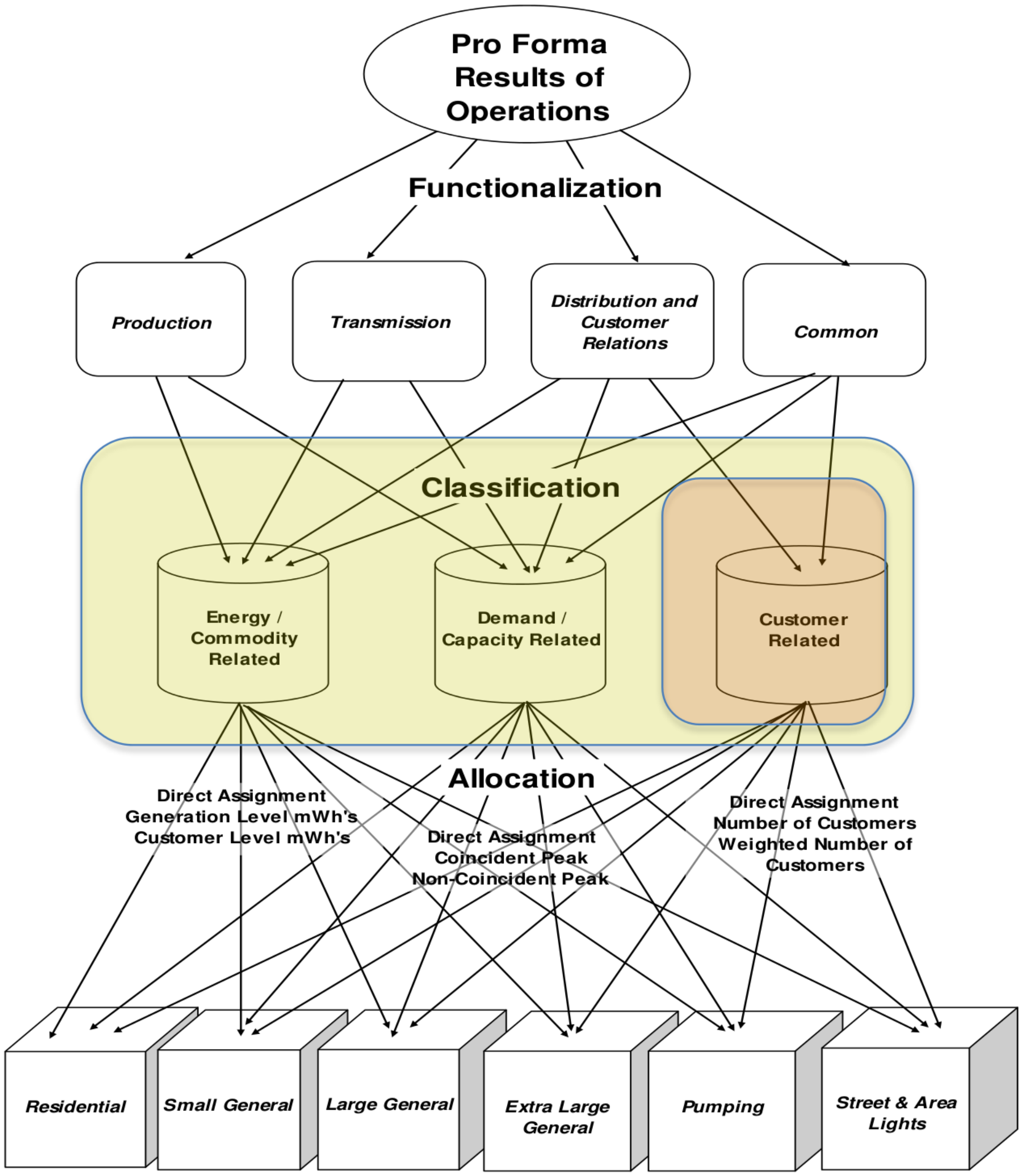
III. ECONOMIC COSTS AND OPTIMAL PRICES

Q. Is an understanding of economic cost concepts helpful in resolving the rate design and revenue allocation issues in this proceeding?

A. Yes. The Company developed an economic cost study, which it characterizes as a “marginal cost” study. It heavily relied on the results of these calculations in developing its proposed revenue allocation (distributing the revenue requirements to different customer classes), and its rate design proposals. In fact, its marginal cost study is the primary – virtually the only – support provided by EnergyNorth for its proposed changes to its existing rate design. While the Company also provided a functional (embedded) cost study, it is only of peripheral importance – helping determine what portion of the Company's revenue requirement will be recovered through base rates and what portion will be recovered through the cost of gas mechanism.

The mechanics of a traditional embedded cost allocation process are well-established and not controversial, although judgments that are made during that process can be very controversial. The mechanics of this process are nicely illustrated in the following flow chart, which was developed by the Regulatory Assistance Project and provided on page 11 of its slide presentation, Smart Rate Design for a Smart Future, dated August 4, 2015.

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

In the first major step, called "functionalization," historical accounting costs are organized into various operating functions (e.g., production, transmission, distribution, customer accounting and customer service). The Company used this process to determine what portion of the overall revenue requirement will be recovered through the Cost of Gas mechanism, and what portion will be recovered through base distribution rates.

In jurisdictions where an embedded cost study is used for rate design purposes, two additional steps are needed. In the second major step – called "classification" – costs are grouped into three rate-related classifications: demand-related, commodity-related, and customer-related. In the third major step, these costs are allocated to specific customer classes. The allocated cost results are also sometimes used to support proposals for specific rate elements – for instance, determining what portion of the cost should be recovered through demand charges, and what portion through customer charges.

The initial steps taken by the Company in developing its marginal cost study were similar to the functionalization and classification steps just described. However, unlike a typical embedded cost study, judgments were not applied in allocating costs to various customer classes. Instead, a similar result was achieved by applying judgments concerning the way various costs were estimated, and the degree to which particular costs were assumed to vary "at the margin." These judgments, occurring within the work papers for the marginal cost study and not discussed in detail in the Company's direct testimony, largely determined the magnitude of the marginal costs that were estimated. In turn, these estimates provided most of the support for EnergyNorth's proposals with respect to the degree to which rates for specific customer classes should be increased (revenue allocation), and the degree to which specific rate elements should be increased or decreased for each class (rate design).

I will discuss some of these judgments in detail later in my testimony. For the moment it is sufficient to note that these judgments were crucial to the final conclusions reached in the study – including the conclusions that were reached concerning the alleged level of fixed "customer costs" (which support EnergyNorth's proposals to increase its customer charges) and the level of "demand costs" (which support its proposals for volumetric rates). The methodology and assumptions used in analyzing "customer costs" and "demand costs" were not consistent. These inconsistencies helped create the pattern of costs which the Company cites as support for its rate design and revenue allocation proposals.

Q. The Company provided both a marginal cost study and an embedded cost study. Can you please explain the difference between these two different types of cost?

A. There are at least three important differences.

First, and most fundamentally, embedded costs are derived entirely from the accounting records of the firm, and are heavily influenced by and dependent upon the conventions adopted by the firm in books and records. In contrast, marginal costs are a particular type of economic cost. Economic costs can be estimated using data from a wide variety of different sources including accounting records, engineering cost estimates, and special studies.

Second, a typical embedded cost study is focused on allocating total costs, whereas a marginal cost study does not (or should not) focus on total cost, or cost allocations. Instead, the focus should be on the extent to which costs vary "at the margin."

Third, because the term "marginal cost" is taken from the economic literature, the usefulness and validity of the Company's marginal cost estimates and its underlying assumptions, should be judged in that context. One way to test the validity of a marginal cost study is to examine how well it matches up with the way economists define and analyze costs. Does the study adequately consider opportunity costs? Is the study focused on a logical, internally consistent "run" or planning horizon? Is the selected planning horizon appropriate given the purpose for which costs are being studied? As I will explain later in my testimony, the Company's marginal cost study fails all of these tests. To understand why it falls short, it will be necessary to explain various concepts from economics.

A. Marginal, Variable, Fixed, and Total Costs

Q. Are there certain economic cost concepts that are important to understanding your analysis of the Company's marginal cost study and pricing proposals in this proceeding?

A. Yes. In economics, the most fundamental and important types of costs are fixed cost, variable cost, total cost, average cost, marginal cost, incremental cost, and stand-alone cost. All of these are integral parts of economic theory – along with other, more specialized cost concepts, including sunk, direct, joint, and common costs. All of these cost concepts are significant to the issues in this proceeding.

Fixed costs do not change with the level of production, during the planning period or "run" under consideration. **Variable costs** change directly (but not necessarily proportionately) with the level of production. It should be noted that the exact same item might be a fixed in the short-run and a variable in the long-run. Together, fixed and variable costs constitute **total cost**, which is the sum of all costs incurred by the firm to produce a given level of output. Dividing the total cost of producing a given volume of output by the total number of units produced, one can calculate **average total cost**.

Short-run costs are those which arise in situations where most costs are fixed. In contrast, **long-run costs** are those calculated under the assumption that many, if not all, costs are variable, and relatively few costs are fixed or sunk. The classic long-run concept is sometimes known as a "scorched earth" approach – that is, no pre-existing plant is considered in the analysis. Instead, the firm is free to build precisely the size and type of plant which best fits the assumed output level. However, even in the long-run some aspects of the production process are typically assumed to remain inflexible – like the technology the firm uses, or the state or region where the firm operates.

Incremental cost is the change in total cost resulting from a specified increase or decrease in output. In mathematical terms, incremental cost equals total cost assuming a specific increment of output is produced, minus total cost assuming the increment is not produced. Incremental cost is often stated on a per-unit basis, with the change in cost divided by the change in output. Incremental cost can vary widely, depending upon the increment of output under consideration. If the entire increment from zero units to the total volume of output is considered, incremental cost is identical to total cost. Similarly, where the increment ranges from zero to total output, incremental cost per unit is identical to average cost per unit for that volume of output. Because a wide variety of different increments can be specified, a wide variety of different incremental costs can be calculated. Thus, in considering any estimate of incremental cost it is crucially important to determine whether or not the specified increment is relevant to the issues at hand.

Marginal cost is the same as incremental cost where the increment is extremely small (e.g., one unit) and the cost function is smooth and continuous. In mathematical terms, marginal cost is the first derivative of the total cost function with respect to output (the rate of change in total cost as output changes).

A wide array of different incremental costs can potentially be defined, corresponding to an array of different increments that can potentially be analyzed. Marginal cost corresponds to one very specific part of this overall array – where the increment is narrowly defined and extremely small. One important distinction between marginal and incremental cost is worth noting here: when large increments are studied, the cost of adding an additional increment of output will often be quite different from the cost of reducing output by an increment of the same magnitude. In contrast, if the cost function is smooth and continuous, marginal cost will generally be the same regardless of whether it is measured by how much total cost increases when the volume of production increases by an extremely small amount, or how much total cost decreases when the volume of production decreases by an extremely small amount.

In the economic literature, a crucial distinction is drawn between marginal costs and average costs. That distinction is closely related to (but subtly different from) the distinction between fixed and variable costs. In essence, average total cost per unit spreads both fixed and variable costs over the total volume of production, while marginal cost does not include fixed costs. However, the discussion can become complicated, because the extent to which particular costs vary "at the margin" can change depending upon the circumstances, including the specific "planning horizon" or "run" that is being studied. The distinction between average cost and marginal cost is of crucial importance to the highly refined understanding of costs that has been developed by economists, which has laid the foundation for much of the progress that has been made in microeconomic theory and empirical research over the past 125 years.

The fundamental reason why I so strongly disagree with the Company's marginal cost estimates is that it has not made appropriate, internally consistent distinctions between which costs are fixed or "sunk" and which costs are variable, and because it has not selected and applied an appropriate, internally consistent planning horizon or "run" that is appropriate to this context. I will explain both of these problems in further detail, after providing the necessary foundation for this explanation.

Q. Can you elaborate on the distinction between fixed and variable costs, and explain how this distinction relates to incremental or marginal cost?

A. Yes. As the name implies, a fixed cost does not increase or decrease as the volume of production changes. In contrast, a variable cost is one that changes in response to changes in production volume. Fixed and sunk costs have no impact on marginal cost. In fact, determining which costs are fixed and which ones are variable is crucial to whatever conclusions one reaches concerning the level of marginal costs in any particular context. It must be kept in mind, however, that the exact same item may be variable in the long-run and fixed in the short-run. Hence, the selected planning horizon – and the extent to which specific costs are assumed to vary in that planning horizon – largely determines the results of a valid marginal cost analysis.

Fixed costs are those elements of the firm's total cost which do not increase (in the context of the specified planning horizon) as the volume of output increases. **Sunk costs** are similar, except that fixed costs can be eliminated if the firm is willing to exit the market entirely (e.g., by abandoning its equipment or converting it to another purpose), while sunk costs cannot be eliminated in this manner. Aside from this difference, sunk costs can be thought of as an extreme case or a special type of fixed cost. Because sunk costs cannot be avoided or changed under any circumstances, they are irrelevant (once incurred) for most economic decisions. In contrast, although fixed costs do not affect marginal costs, they are not entirely irrelevant, because they can be avoided if the firm is willing to exit the market.

A typical example of a fixed cost is the cost of owning a factory building; as long as the building is in use as a factory, its costs are unavoidable and they do not vary with the volume of output produced by the factory. However, the firm can avoid the costs of ownership if it discontinues production and sells the building to someone who will convert it to another use (e.g. condominiums or a factory producing a different product). Hence, the cost of the building would be classified as fixed, not sunk, to the extent the building can be converted to a different purpose.[16] If the building has been optimized for a specific production process, it will likely involve a combination of fixed and sunk costs. To the extent a willing buyer would not pay extra for these unique attributes, and instead

16 A mere change in legal ownership is not sufficient; the potential to convert to a different use helps determine whether a cost is fixed or sunk.

would simply demolish them or ignore them, the cost of those unique attributes would be sunk.

Q. Can you clarify the distinction between fixed and sunk costs?

A. Yes. A few examples will suffice. A natural gas utility incurs some capital-related costs, like property insurance and property taxes, that economists classify as fixed costs, because they do not vary with day to day or month to month fluctuations in the volume of production. That is not to say they cannot be changed under any circumstances. Fixed costs can typically be reduced or eliminated by divesting, shutting down, or abandoning some of the firm's capital investment. In the case of a gas utility, it could potentially reduce its property insurance by disposing of some of its equipment, or it might be able to reduce its property taxes by permanently shutting down parts of its system. Since a gas distribution system cannot be moved to a new location, economists classify the capital invested in the system itself as a sunk cost (rather than a fixed one), except to the extent portions of that capital investment can be recouped by selling parts of the system to another firm that converts it to a different purpose. For instance, if a telecommunications carrier would be willing to purchase parts of the distribution system in order to convert some of the pipes into conduit for fiber optic cables, the price the carrier would be willing to pay for the pipes would be classified as a fixed cost of the gas utility; the remainder of the investment would be classified as sunk.

A classic example of a sunk cost is the cost of writing a novel. Once this cost is incurred, it cannot be avoided, reduced or eliminated, regardless of whether or not the novel is published or how many copies are sold. Stated another way, sunk costs are irretrievable once they are incurred. From that point forward, they are completely irrelevant to any pricing, production, or other economic decisions that must be made.

B. Long-run versus Short-run

Q. Can you elaborate on the distinction between long-run and short-run economic costs?

A. Yes. The degree to which costs are variable depends on the "run," which is a technical term that is closely tied to the concept of a "planning horizon." In the short-run, the firm minimizes its costs by focusing on options, like hiring or firing employees or adding overtime, which can be analyzed and implemented quickly. Notably, the firm's existing capital investment is considered to be a fixed or sunk cost in the short-run. Additional, more fundamental, changes in the firm's operations become feasible over longer periods of time. These options include investing in additional plant and equipment, replacing some of its existing equipment with a different type of equipment, or selling some of its capital equipment and scaling back the scale of its operations. By definition, none of these options are available to the firm's managers in the short-run, because of the durability of its existing capital investment, and the difficulties involved with making changes to that investment.

While it is simpler to discuss these concepts by contrasting just two "runs" – the "short-run" and the "long-run" – it is more accurate and realistic to think in terms of an entire continuum of possibilities, or "runs." The longer the "run", the greater the extent to which the capital-related factors of production can be varied and optimized. Stated another way, as the planning horizon becomes longer, the firm is not as limited by, or significantly constrained by, inherent limitations and characteristics of its existing capital investment.

Similarly, while it is easier to simplify the discussion by equating the “run” with different periods of time, it's important to recognize that the extent to which capital-related factors of production can be varied, (and how long it typically takes for a firm to replace its existing capital stock), can vary greatly across different industries. The time period corresponding to the “short run” in one industry might correspond to the “long-run” in a different industry. While the “run” is related to time, the amount of time is not as important as the degree to which the factors of production can be optimized.

In general, as the “run” becomes longer, it becomes feasible to analyze and optimize more and more aspects of the firm's production process, including more and more aspects of the firm's capital investment. Economists often explain the concept of the “run” with reference to time, because this makes it easier to understand how additional options open up for the firm as it moves along the continuum from the short-run to the long-run. For example, as the amount of available time for making decisions and implementing them increases, the firm will need to decide how, and whether, to replace equipment that is wearing out. Similarly, with more time the firm may be able to find someone willing to purchase some of its existing equipment and move it to a new location, to be used in a different production process.

By thinking in terms of how the firm can respond differently over different time periods it is easy to grasp the key attributes of the economic concept of the “run”. For instance, it is easy to see why the cost of a machine with a useful economic life of five years will be classified as fixed in a six month planning horizon, but the cost of that same machine will be reclassified as variable over a ten year planning horizon. Hence, there is no universally "correct" way of classifying any particular item. That does not mean that "anything goes." There are clearly "wrong" ways of classifying specific costs in any given planning horizon. It is self-evident that if the planning horizon is long enough to allow the firm to replace an existing machine with a different size or type of machine, then the electricity used to operate the machine should also be classified as a variable cost. Similarly, if a cost is classified as variable in the short run, it has to be classified as variable in the long run, as well. One cannot arbitrarily pick and choose which items will be categorized as variable or fixed – logical consistency is mandatory.

Q. Can you provide an example which clearly illustrates the concept of the "run"?

A. Yes. A classic example used by economists is the costs incurred by a fisherman. To make this example easy to relate to, it is usually introduced and explained in terms of time – noting that all costs may be fixed over a short period of time, but many of these cost become variable over a longer period of time. However, to fully appreciate the nuances of this example, it is helpful to keep in mind that in economic theory, the "run" does not actually refer to any specific period of time. Rather, the "run" refers to the degree to which costs (particularly capital investments) are assumed to be variable, rather than fixed or sunk – and in our common experience this variability is correlated with time.

Q. Can you use this illustration to clarify how the "run" relates to time, at the short end of the spectrum?

A. Yes. Economic theory envisions a continuum of different planning horizons. The extreme short end of the continuum is sometimes referred to as the "market period." This corresponds to the situation confronting a fisherman during the brief period after unloading the fish but prior to selling them. The load of fish cannot be "uncaught" and the costs of catching the fish cannot be reduced by reducing the size of the catch. Nor can costs be reduced by selling some of the fish and throwing the rest away. The costs of catching the fish are sunk, and cannot be avoided or varied at that point.

However, an entire array of "runs" exists. Consider a slightly different example, which can also be classified as an example of the "extreme short-run" – the situation confronting the fisherman during short period after the fish are caught until they are sold. The cost of fuel that was burned while locating and catching the fish is a sunk, but the cost of the additional fuel needed to haul the heavy catch all the way back to shore can potentially be avoided by dumping the fish overboard. The small amount of labor that could be avoided by dumping the catch overboard and coming more quickly back to shore can also be avoided (in theory). Accordingly, over this slightly longer time period, the marginal cost per pound of fish would be slightly higher than the even more abbreviated "market period". Needless to say, in both of these examples, the total costs incurred by the fisherman are far above zero, and the captain's goal is to recoup all of the costs, including the sunk costs.

Q. Can you extend this example to illustrate the "short-run"?

A. Yes. The classic short-run is a planning horizon where the fisherman has many more options than in the market period or the extreme short-run, but all of the fisherman's capital costs remain fixed. It is easy to envision some of these options if you visualize what the fisherman can do over the course of a week or two. For example, the cost of fuel and labor can be varied, as the fisherman decides how much time to spend on the water each day, or how many days per week she will go fishing. By spending more time on the water, the fisherman can catch more fish, at the cost of burning more fuel. Looking at the same option from the other direction, the amount of fuel burned can be limited on a daily or weekly basis, but this reduction in fuel costs will typically result in fewer fish being caught.

If the captain chooses to use more fuel and spend more time on the water, the marginal cost per pound of fish acquired will begin to increase, once a point of diminishing returns is reached, because she will be forced to spend more and more time on the water, searching farther and farther afield from the prime locations where a lot of fish can almost always be found. This extra time on the water will help the fisherman bring back a larger catch, but there will be higher variable costs, because of the extra fuel that will be burned. If this strategy is pursued too far, the boat could become overloaded, and the captain will be forced to slow down when returning to shore, in order to avoid capsizing the boat. All of these factors tend to drive up the marginal cost of each pound of fish brought to shore, once the point of diminishing returns is reached.

Similarly, in the short-run the fisherman can hire additional workers to go out on the boat. These workers help haul in the nets more quickly, increasing the size of the catch for any given expenditure on fuel. However, this strategy will increase short-run marginal cost, since the extra workers will need to be paid for the entire time they are on the water – not just when they are actually needed to help with bringing up the nets.

Q. Can you extend this example to illustrate the "long-run"?

A. Yes. The long-run corresponds to a planning horizon where most capital-related costs become variable – the fisherman is assumed to have many capital-related options. While the long-run is not tied to any specific period of time, in the fishing context it can be thought of as a time period that is long enough to provide an opportunity to investigate and evaluate capital-related options, like replacing the existing boat. For example, the fisherman might evaluate the option of selling the existing boat and buying a faster one with more powerful engines. This would make it feasible to the prime fishing spots more quickly, saving time, and provide the option of going to additional locations on days when the catch is poor at the first location. Or, the fisherman could invest in a larger boat, which would allow the captain to haul more fish back to shore (at least on days when enough fish can be found to fill the larger boat).

The fisherman could also evaluate less drastic capital-related options, like installing better, more powerful gear for hauling in the nets. This might reduce labor costs without requiring a change in boats. Similarly, the fisherman might invest in technology which helps quickly and precisely find the fish, so less time will be wasted letting down the nets and hauling them back up with a disappointing catch. In the long-run, there will be options for reducing the capital investment – not just increasing it. For instance, a smaller, cheaper boat might be chosen, which costs less to own and operate, but doesn't hold as many fish. In the long-run, this might allow the fisherman to increase profits by more closely conforming the boat to the size of the catch that can easily be found and hauled back on a typical day. With a smaller boat, the fisherman might be able to focus exclusively on prime fishing locations, without wasting so much time going to other, less reliable, or less plentiful locations in an effort to fill the existing boat.

As this example demonstrates, while the difference between the short-run and the long-run can easily be envisioned and discussed in terms of time periods of different durations, the really crucial difference is the degree to which capital costs are variable. In the short-run, the fisherman is stuck with the existing boat, which represents a fixed cost that cannot be easily avoided or varied. In the short-run, the fisherman cannot change the capacity, technology, configuration and other attributes of the existing capital equipment. Hence, all of the costs of owning the boat, including the cost of capital, insurance, and property taxes are fixed (they cannot be varied) in the short-run. In turn, it is easy to see why marginal costs would not necessarily be the same in the short-run and the long-run. Since marginal cost is the rate of change in total cost resulting from an extremely small change in output, differences in the degree to which various costs can be varied will result in differences between short-run marginal cost and long-run marginal cost.

Q. Can you clarify some key differences between the long-run and the short-run in the specific context of EnergyNorth?

A. Yes. Compared to the fishing example, a gas distribution system has high capital-related costs relative to size of the other, more easily varied, costs. Hence, EnergyNorth's marginal costs are necessarily going to be far below its average total cost in the short-run. This follows directly from the fact that in actual practice, the Company's costs are mostly fixed or sunk, and ample capacity undoubtedly exists along many of the routes where it has installed distribution mains. As a result, most customers can be delivered as much gas as they want, whenever they want it, without incurring "opportunity costs" or the need to curtail the delivery of gas to other customers.

This is in contrast to the fishing example, where every pound of fish that is caught increases the amount of fuel that is burned, and where time and space constraints create trade-offs or "opportunity costs" that increase short-run marginal costs. The amount of one type of fish that can be brought back to shore during any given fishing trip will be limited by the amount of other types of fish that are also brought back on the same trip. In effect, increasing the volume produced of one product (the harvesting of a particular type of fish) will make it more difficult or costly to produce any other products (the harvesting of other types of fish). Space is limited on a boat, and the time spent hauling in one type of fish will reduce the time available for hauling in a different type of fish – all of which translates into higher short-run marginal costs for any given type of fish.

To some degree, something analogous can apply to parts of EnergyNorth's gas delivery system. If capacity constraints or potential low pressure conditions exist on parts of the system, these problems will translate into higher short-run marginal costs. Low pressure problems can result in opportunity costs because increased deliveries to one set of customers can only be accomplished safely by reducing deliveries to another set of customers, which will increase short-run marginal costs.

As a general matter, however, we can anticipate that the short-run marginal cost of delivering gas to most customers will be very low (approaching zero) during most of the year. Because short-run marginal costs are so low, it is readily apparent that gas delivery prices that are set equal to short-run marginal cost will not allow EnergyNorth to recover its revenue requirement. A substantial contribution above short-run marginal cost is necessary for the firm to remain viable and ensure recovery of its total costs over the long-run.

Because many capital investments can be varied in the long-run, the long-run marginal cost of distributing gas will likely be much higher. Consider, for example, a long-run planning horizon that corresponds to the degree to which capital investments can potentially be varied over a typical 10 to 20 year planning horizon. Unlike in the short-run, in this longer planning horizon, the cost of EnergyNorth's distribution mains is not entirely fixed or sunk, and will instead (to some degree) be variable. For instance, over this time period new mains may need to be installed along some routes, because the existing mains are nearing the end of their useful life, or becoming unacceptably leak-prone. Over a 10 to 20 year time period, some degree of congestion will likely arise, with growth in usage in some areas creating opportunity costs (a reduction in usage by one group of customers might be necessary to accommodate increased deliveries to another group of customers) or the need for investments in main reinforcements or expansion.

Q. Can you explain in more depth why the long-run marginal cost of delivering gas tends to be higher than the short-run marginal cost?

A. Yes. There are several factors that determine the extent to which marginal costs will differ between the short-run and the long-run. These factors will differ depending on the technical characteristics of the production function, but in the specific case of a natural gas utility, the overall tendency will be for long-run marginal costs to be higher than short-run marginal costs. The additional flexibility that is available in a long-run planning horizon will provide opportunities to reduce total costs that don't exist in the short-run, and in some situations this can translate into lower marginal costs in the long-run than in the short-run. However, costs that were classified as fixed or sunk in the short-run may be reclassified as variable as the planning horizon becomes longer, and this will tend to push long-run marginal costs above the level of short-run marginal cost (as fixed and sunk costs diminish in importance). Accordingly, we can confidently state that long-run marginal costs exceed short-run marginal costs for a typical gas distribution utility, since fixed and sunk costs are pervasive in the short-run, pushing short-run marginal costs down to very low levels.

While decisions concerning the replacement or retirement of certain mains, as well as the size of these mains can be optimized over the course of a longer planning horizon, these costs are not eliminated. To the contrary, due to the high cost of installing, reinforcing or replacing mains, the overall system-wide long-run marginal cost of mains will be far above the level observed in the short-run. In fact, due to inflation and other factors, the long-run marginal cost of mains could easily exceed the average embedded cost of the existing mains, despite the fact that the cost of mains in some parts of the system may still be classified as fixed or sunk.

Q. Are you suggesting that some fixed or sunk costs can still exist even in the long-run?

A. Yes. The distinction between treating capital-related costs as variable and treating them as fixed or sunk is fundamental to the concept of the planning horizon. In application, however, the theory is quite flexible, and can readily be adapted to different factual situations. There is nothing illegitimate or inappropriate about studying a planning horizon in which some of the firm's capital investment can be varied, while other aspects of its existing system are treated as fixed. Since the natural gas industry has extremely long-lived assets, this may be a much more relevant and realistic application of the "long-run" concept than a traditional "scorched earth" planning horizon, in which every aspect of the firm's capital investment is treated as variable.

Most of the pipes and other facilities owned by EnergyNorth have a useful economic life of 60 to 70 years or more. To entirely eliminate fixed and sunk costs it would be necessary to select a planning horizon or "run" that corresponds to an extremely long period of time – perhaps 100 years – but this would more typically be described as an "extreme long-run" planning horizon lieing at the extreme far end of the continuum of possibilities. In this extreme long-run, all costs would be assumed to be 100% variable, including those that can only be changed in a purely hypothetical scenario, or one that involves an extremely long period of time like 100 years.

In the fishing example, in contrast, the extreme long-run would not require such a long time period. Instead, it would involve a purely hypothetical analysis in which the firm is assumed to have not yet entered the business, and it is free to choose whether to operate out of Portsmouth, or to fish off the coast of Oregon or Alaska, or to invest in aquaculture to raise farm-bred fish, instead. Similarly, in the case of EnergyNorth, the equivalent extreme long-run planning horizon would involve a purely hypothetical scenario in which the firm has no sunk costs – it is considering the option of entering the market, and it has complete freedom to choose the locations where it will provide gas service, the routes where it will install distribution mains, and the specific buildings it will connect to its mains.

It is certainly possible to develop a cost study based upon "scorched earth" assumptions, in which the existing system is ignored. This would be a purely hypothetical system, which is optimized to fit current population and usage patterns. In that case, every main, every regulator, and every service line would be treated as 100% optional or variable. However, in my opinion, that analysis would not be particularly useful or relevant in this proceeding. The key questions in this proceeding can best be answered by taking a more realistic approach to analyzing economic costs. Many aspects of EnergyNorth's system should be taken as a given, and as a result some of its capital-related costs are more correctly classified as fixed or sunk.

Q. Can you clarify what you are recommending with regard to how long-run marginal costs should be defined in this proceeding?

A. Yes. The approach I am recommending can be thought of as the typical of a "long-run" which reflects the degree of flexibility that actually exists over a 10 to 20 year time period. This is similar to the time frame that is usually envisioned when discussing long-run costs in the context of a manufacturing firm. For instance, in the long-run it would typically be assumed that a manufacturer is not limited to the configuration and scale of its existing factories. The existing building can be abandoned or sold to someone who will use them for a different purpose; the firm can replace it with a different size factory, or one in a different location. However, it will likely have at least some aspects of its operations that remain fixed. For example, inventing and implementing an entirely new production process would not be an option – that sort of hypothetical possibility would be relegated to the "extreme long-run".

The approach I am recommending is more useful and appropriate than a purely short-run approach, or an extreme long-run approach. The distinction I am drawing is important because many of the facilities owned by EnergyNorth are installed in the ground and cannot be easily removed or downsized, yet they have a useful economic life of 60 years or more. During a 10 to 20 year time frame, only some of these facilities will need to be replaced or reinforced. Many parts of the system will remain unchanged no matter what decisions customers make in response to the prices that are established in this proceeding. It would be a mistake to ignore this reality and to arbitrarily treat sunk costs as if they were not sunk. It would be particularly inappropriate to treat sunk costs as if they were 100% variable, on an arbitrary, purely hypothetical basis. The truth is that many items in the system cannot be removed, replaced, or resized at will. While the latter view of cost variability is sometimes used in a “scored earth” planning horizon, it is not appropriate for use in this case.

That is not to say that purely short-run view of costs should be used. More useful and meaningful insights can be developed by thinking about the costing problem from the perspective of 10 to 20 year planning horizon, and recognizing that an array of different situations exist in different parts of EnergyNorth's New Hampshire service area. Along the existing route sending gas to any given customer, there is a certain probability that capacity constraints will result in significant opportunity costs over the next 10 to 20 years. Over a similar time scale, there is also a certain probability that usage growth, leak-prone pipes, or safety concerns will result in a need to reinforce, replace or enhance parts of the system (unless those parts are downsized or abandoned).

Consumption decisions by customers who are served by many parts of the system can potentially accelerate or delay the need for investments over the next 10 to 20 years, and their decisions can increase or decrease the magnitude of these investments. Similarly, customer decisions to increase or decrease gas consumption can potentially increase or reduce congestion on various parts of the system, which in turn will translate into opportunity costs that will increase the system-wide level of long-run marginal costs.

Appropriately developed, a system-wide measure of long-run marginal costs will consider the configuration and characteristics of the entire system, and potential future changes to that system, in conjunction with a distribution of probabilities. By considering this entire array of probabilities, circumstances where opportunity costs and capital replacement or expansion costs are high can be weighed with circumstances where marginal costs are low (for instance, where existing capacity can safely serve all relevant levels of demand over the next 50 or 60 years).

When viewed in this way, costs can analyzed on a precise, granular basis, reflecting the fact that the long-run marginal cost of distributing gas will be higher in locations where congestion or other problems will soon emerge, and lower in locations congestion is less of a concern, and capital-related costs are almost entirely sunk. This granular approach would be particularly useful if the analyst is considering the option of charging different prices in different geographically areas, or establishing a new sub-category of customers for pricing purposes. For instance, this sort of geographically granular cost data could be used to develop higher prices for customers in newly added residential neighborhoods or lower prices for commercial and industrial customers brought onto the system in an economic development zone where excess capacity exists.

The thrust of this discussion, however, is not to show how prices might be geographically de-averaged (which is not normally up for discussion). Instead, the point is that wide differences in circumstances at different locations in the system do not need to be ignored or simplified away; instead, these differences can be evaluated in terms of an overall system-wide distribution of probabilities. If customer's can sometimes reduce the total cost of the system by reducing their usage or leaving the system, and sometimes their decisions will have no impact due to pervasive sunk costs, both possibilities can be considered and weighed relative to the probability and relevance of each possibility. This is similar to the way automobile or fire insurance rates will often be based upon a detailed analysis of different circumstances. The actuaries recognize that risks vary depending on many different granular factors, but they ultimately roll up this information into broader prices which reflect an assessment of the overall pattern of probabilities and characteristics for an entire community, or a carefully defined category of customers.

C. Joint and Common Cost Recovery

Q. Earlier you mentioned joint and common costs. Can you please define these concepts, and explain how they relate to each other?

A. Yes.

Common costs are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs; however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately (this is referred to as economies of scope).

Joint costs are a specific type of common cost—they are incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather, and how much from the change in the quantity of beef.

Q. Are joint costs relevant to the issues in this proceeding?

A. Yes. Joint costs create a challenging puzzle for economic theory: it is not immediately obvious how joint costs are recovered in competitive markets, since they do not show up in the marginal costs which normally explain how prices are determined. The solution to this puzzle, which was discovered in the early 1900's, sheds light on some key aspects of EnergyNorth's pricing proposals in this case.

The solution to this puzzle is not only relevant to markets where joint costs are important (beef and hides) but also to markets where sunk costs are important (novels), for much the same reason (marginal costs may be close to zero). Understanding how prices are established when marginal costs are close to zero – or at least, too low to recover total costs – is useful in resolving some of the pricing issues in this case –

especially since many of the costs included in the Company's revenue requirement are to some degree sunk, or joint, or both.

Q. Before explaining how joint costs are recovered, can you explain how prices relate to marginal cost where the joint cost problem isn't present?

A. Decades before the joint cost puzzle was solved, economists had figured out that prices tend to equilibrate to a level that is equal to marginal cost. In fact, in situations where firms are accepting a market-determined prevailing price, marginal cost is the key to understanding how that prevaiing price is established. Among other insights gleaned from this analysis is that average cost is much less important than marginal cost.

A classic example is a wheat farmer. A wheat farmer has no control over the weather, and no control over the price of wheat, which is decided through nationwide forces of supply and demand. Hence, he concentrates on optimizing those aspects of his production function that he can control (deciding how many acres to plant, what crop rotation system to use, what seed to plant, how much fertilizer to use, how much to irrigate) in an attempt to maximize profits.

Like all competitive firms, wheat farmers make these types of decisions based on an analysis (whether explicit or implicit) that is tightly linked to marginal cost, rather than average cost. The firm increases each factor of production beyond the point of diminishing returns, until the point where the marginal revenue product associated with each input is equal to marginal resource cost of that input. While each firm makes these decisions independently, their individual decisions collectively lead to a convergence of industry-wide prices and marginal costs. In fact prices will exactly equal the industry-wide level of short-run marginal cost if the industry is in short-run equilibrium, and prices will equal long-run marginal cost if the industry is in long-run equilibrium. In equilibrium, every firm's marginal cost will exactly equal every other firm's marginal cost, despite wide differences in their individual circumstances, like the fertility of their soil, the types of equipment they use, and other details of their production function, and despite the lack of any coordination in their individual production decisions.

Because joint costs do <u>not</u> directly vary with the output of any one product, they are an exception to this general pattern, and it is not self-evident how they are recovered from customers. Among other insights that can be gleaned from solving the joint cost puzzle is that the general equilibrium conditions that were just described are not achieved exclusively by costs being adjusted to match prices. To some extent, the process also works in the reverse direction: prices also tend adjust to the level of marginal costs incurred by the typical firm. Decisions made by <u>both</u> producers and consumers are important in establishing prices in competitive markets. Succinctly stated, the interaction of both supply and demand determines what costs are incurred by producers and what prices are paid by consumers.

Q. Before explaining the joint costs in more detail, can you briefly summarize the solution?

A. Yes. Unregulated prices tend to reflect the direct costs incurred by producers – particularly marginal, or variable costs – <u>plus</u> a contribution toward otherwise unrecoverable indirect, joint and common costs that varies depending on market conditions and the strength of demand for different products or services. While market forces typically push prices toward short-run marginal cost, there are other market forces that push prices toward a long-run equilibrium level that exceeds this level, when this is necessary to ensure that each price includes an adequate contribution toward joint and common costs so that a typical firm can recover its total costs. In fact, demand conditions help determine the extent to which the firm's costs are recovered from specific products or services, and the extent to which its costs are recovered from specific customers or customer groups.

More specifically, if purely marginal cost-based prices would not be sufficient to ensure adequate total cost recovery, prices will instead equilibrate (in the long-run) toward levels that exceed marginal cost by the amount necessary to enable the typical firm to recover its joint and common costs. Significantly, this demonstrates that competitive prices are not purely a function of marginal cost. Instead, prices are determined by market forces, with the interaction of supply and demand determining the relative share of joint and common costs that are provided (over and above marginal cost) by different products and customer groups. This holds true in markets for many different types of goods and services – even where competition is only partly effective, and individual firms enjoy a substantial degree of market power.

Q. How does this discussion relate to this proceeding?

A. Because EnergyNorth is a rate-regulated monopolist, the Commission decides what prices are charged for gas delivery. Substituting for market forces or the interaction of supply and demand, the Commission decides how the Company's costs will be recovered during the revenue allocation and rate design phase of each case.

Many of the costs included in the Company's revenue requirement are fixed or sunk. Accordingly, prices set equal to marginal cost will likely fail to recover the Company's revenue requirement, assuming marginal cost is accurately estimated over the short- to long-run. Typically, there is little or no controversy concerning the recovery of short-run marginal costs, which are primarily variable costs that can be clearly and unambiguously be traced directly to specific customers. For instance, there is usually very little controversy concerning the appropriate price a utility should charge for the natural gas it purchases from an interstate pipeline and delivers to its customers. Most parties will readily agree that it is reasonable to charge a price that closely approximates the short-run marginal cost of gas – an amount which is approximately equal to the amount EnergyNorth pays for gas received during the hour when it is consumed. Any complications in deciding what to charge different customers will usually be a function of differences in customer usage patterns, and corresponding uncertainties concerning the precise timing of when each customer's gas was purchased (since gas prices fluctuate daily, and because gas can sometimes be purchased in advance and stored for use during peak hours).

Recovery of the cost of purchased gas is relatively straightforward. It is more difficult to determine how much each customer should be charged for using pipes and other facilities that are buried underground and shared by hundreds or thousands of different customers. Among other complicating factors, customers are in different locations (some are closer to the interstate pipeline, some are farther away), and they may use gas to a different extent during different times of the day and year. Consequently, EnergyNorth's distribution system gives rise to both fixed and sunk costs, and – due to economies of scale and scope – it inherently involves the problem of joint and common cost recovery.

To understand why I say this, consider first the way costs can be incurred jointly across time. In fact, as EnergyNorth installs gas distribution mains, it adds delivery capacity in fixed proportions across different times of the day and different months of the year. Even if a capacity addition is motivated by a need to increase capacity during the peak hour, the same amount of additional capacity will become available to serve load during other hours of the day, as well. Similarly, in the long-run, when capacity is increased or decreased in response to changes in winter gas usage, capacity in the summer will increase or decrease by the same amount. Hence, gas delivery during off-peak hours can be thought of as a byproduct of delivery during peak hours, and summer gas delivery can be viewed as a byproduct of winter gas delivery.

The pervasive existence of fixed and sunk costs, compounded by a joint cost problem across different time periods and geographic locations, results in a situation where very few costs can be reduced or avoided if any single customers' usage increases or decreases by a small amount. In other words, the marginal cost of delivering a little more or a little less gas to a typical customer will be relatively close to zero. Even the long-run incremental cost savings that would be achieved if a typical customer were to discontinue their gas usage entirely (permanently leaving the system) might be very small compared to the average cost of serving a typical customer. Under these circumstances, prices cannot be set equal to marginal cost and still generate enough revenue to recover EnergyNorth's total costs.

Q. What is the solution to the joint cost puzzle?

A. The answer is straightforward, but not obvious: in competitive markets, relative levels of value – or benefits – largely determine the share of joint costs recovered from each of the joint products. If two products are jointly produced, the most valuable product, or the one that receives the largest benefit from the joint production process, will pay the largest share of the joint costs. The least valuable product, or the one that receives the smallest benefit from joint production, will pay the smallest share.

Recall that joint costs are incurred when production processes yield two or more outputs in fixed proportions. Two classic examples are the production of beef and hides and the production of cotton and cottonseed. The costs of raising and slaughtering cattle are part of a joint production process that produces both meat and hides, in relative proportions than cannot easily be adjusted by the cattle farmer. Similarly, cotton and cottonseed oil are both part of a joint production process, in proportions that cannot be easily adjusted.

The cost of fattening and slaughtering cattle are paid by consumers of both beef and hides, while the cost of growing and harvesting cotton are recovered from consumers of both cotton and cottonseed oil, in proportions that depend on the relative value of each of the joint products (not their respective marginal costs). For example, if hamburger is not highly valued (because consumers don't particularly like hamburger, or they prefer chicken or seafood), but leather is highly valued, a surprisingly large fraction of the cost of cattle feed may be borne by the purchasers of leather goods. Similarly, if the purchasers of gloves are willing to pay more for leather gloves than for cloth gloves, they may end up paying a relatively large share of the cost of cattle feed while the purchasers of cotton gloves may pay a relatively small share of the cost of growing cotton (and consumers of cottonseed oil may pay a larger share than might otherwise be expected).

Once the solution to the joint cost puzzle is explained, for many people it will seem intuitively logical and fair. The purchasers of both leather gloves and hamburgers benefit from the joint production process so it intuitively makes sense that both will contribute to the cost of joint production. Similarly, the demand for both beef and leather products is strong, so it seems logical that market forces would lead to both consumers of both sets of products to contribute toward the joint costs of raising and slaughtering cattle.

Different customers pay different amounts, depending on how much benefit they derive from the joint production process. Those consuming the most highly valued products (for which demand is strong) will pay the largest share of the joint costs, while those those consuming the least valuable products (for which demand is weak) will pay the least. This principal applies not only to the distinction between beef and hides, but also to different types of beef, or different sections of the hide. A customer that purchases hamburger will end up paying more per pound toward the joint costs of cattle production than one who purchases standing rib roast or filet mignon.

Q. Does joint cost recovery differ when one of the products is primarily driving production decisions and the other product is a mere byproduct?

A. No. Even if cottonseed is just a minor byproduct of the production of cotton that is used in manufacturing T-shirts and bed linens, the cottonseed is valuable, so it will not be discarded. Instead, the seeds will be converted to cottonseed oil, and consumers of this byproduct will make a contribution to the joint costs of raw cotton production. The status of one item as the primary product and the other as a byproduct does not change the pattern of cost recovery, nor does it indicate that consumers of the main product will pay nearly all of the joint costs. If the byproduct is valuable, purchasers of the byproduct will benefit from its production, and they will contribute toward the cost of the joint production process. Succinctly stated, the strength of demand for the byproduct will determine how much those consumers pay toward the joint costs.

A somewhat analogous joint cost phenomenon arises geographically within EnergyNorth's system, since the same pipe can be used to deliver gas to more than one location. Furthermore, pipes are manufactured in "lumpy" sizes, and their installed cost involves substantial economies of scale. If a 4" main is not quite adequate to serve the anticipated future usage of customers in a particular neighborhood, the next largest size considered might be a 6" main, which provides more than double the capacity with only a small increase in the installed cost per linear foot. If the 6" main is installed it will have substantial excess capacity that will be available to accommodate growth in usage in other locations. This is another example of the joint cost phenomena, analogous to an increase in beef production creating an increase in the volume of hides that become available for tanning and sale to leather purchasers.

Q. How do joint costs relate to common costs?

A. Joint costs are simply a special type of common cost. To the extent common costs vary in proportion to output, they will be recovered in competitive markets in the same manner as direct costs: they become part of the marginal cost of producing each individual product, and will therefore directly impact prices (since prices tend to equilibrate towards marginal cost). However, production processes sometimes include common costs that give rise to significant economies of scale or scope. The recovery of common costs will, to that degree, follow the same pattern as the recovery of joint costs.

Since joint costs occur don't have an impact on marginal cost, the way they are recovered is on the basis of demand characteristics (value and benefits). Similarly, if economies of scale and scope are pervasive in a common production process, a markup above marginal cost will be necessary for the firm to stay in business. Market forces will lead to equilibrium conditions in which the price of each product will exceed the marginal cost of producing that product by an amount that depends on supply and demand conditions for that product. In essence, the markup recovered from each product will depend on how much the product is valued by consumers (or the benefit obtained from producing it in common with other products). Assuming equilibrium, on an overall basis, the contribution from each product, over and above recovery of its marginal cost, will be just enough to enable the firm to recover its total costs and stay in business.

Q. Can you please elaborate on differences in the amounts that will be paid by different customers toward the recovery of joint and common costs?

A. Yes. The portion of the joint and common costs that are recovered from different products or services will vary depending upon supply and demand conditions. More specifically, the relative cost-recovery shares will depend on the degree to which purchasers of different products benefit from the joint production process, the value of the different products, and the relative strength of demand for the different products. In other words, a uniform markup will not be added to marginal cost, and each customer will not contribute a uniform dollar amount toward the recovery of joint common costs. Instead, joint and common cost recovery will vary widely. Larger customers will tend to contribute more than smaller customers (because they use more, and therefore benefit more from the common production process). Similarly, more valuable products will tend to have a larger markup, resulting in a contribution toward joint and common costs than less valuable products.

In general, the amount contributed by specific customers (or specific products) will vary depending on the strength of demand in the different markets and submarkets. The stronger the demand – and in that sense, the greater the benefit received from the joint production process – the greater the share of joint costs that will be borne by any particular product, service, customer, or customer group. If General Motors incurs common costs when producing Chevrolet and Cadillac automobiles, to take advantage of additional economies of scale or scope, we can confidently predict that a larger share of the common costs will end up being recovered through a large markup above marginal cost built into the wholesale price of each Cadillac, while a smaller share of the common costs will be recovered in the wholesale price of each Chevy.

Q. You've also mentioned sunk costs several times. How do they relate to this discussion?

A. There are some striking similarities between joint costs and sunk costs. Once they are incurred, sunk costs are irrelevant to the pricing process. However, the mere fact that some costs are sunk does not mean the firm has no chance of recovering those costs, or will be forced out of business. The cost of writing a novel provides a good example. The actual amount of time and effort invested the writing process by a novelist is entirely irrelevant to what the writer will be paid for their work. Once a novel is written, the cost of creating the novel is sunk and irretrievable. Assuming a competitive market, this sunk cost will have no bearing on what publishers will bid for the right to publish the novel.

Similarly, once a publisher purchases the rights to a novel, the amount it pays for those rights, the cost of hiring an editor to work with the author in polishing the manuscript, the costs of typesetting, and various other costs leading up to and including the cost of the initial print run become sunk costs as they are incurred. These sunk costs are irretrievable and irrelevant to any subsequent pricing decisions. Not only will they have no bearing on the price the publisher asks for copies of the novel, they will little or no impact on how many copies are ultimately sold – that will depend almost entirely on how good the novel is, and how popular it becomes.

None of this suggests that sunk costs are never recovered. Successful authors are paid well for their work. If they were not, fewer novels would be created, and publishers would be forced to bid up the price paid for any novels that continue to be written. Market forces ensures that novels continue to be written and publishers continue to take a chance on publishing new books, despite the risk that their costs will be sunk, and may not be recouped. The parallel is clear: sunk costs incurred by any one author or publisher have no impact on marginal cost, and thus they have no impact on prices, yet these costs are often recouped, ensuring that novels continue to be written and published.

Q. What determines whether, and how, sunk costs are recovered?

A. Value. For instance, the sunk costs of producing a book will be recovered only to the extent the book itself has perceived value. The amount paid for each individual copy, and the total number of copies that are sold, will depend on the market for novels and the extent to which there is demand for this particular novel. If the novel is entertaining and well written, if it features interesting characters and a plot that people like, word will spread, and many copies will be sold at a price that customers consider to be fair for the value they receive. If enough people are eager to buy the book, they will pay a price that greatly exceeds the marginal cost of production (say, the cost of printing and binding one more copy in the course of a large print run). If the book is a dud, most of the copies will be destroyed, and the rest will linger on the "remainders" table, after being marked down to a price that is below the marginal cost of production. Either way, the sunk costs incurred by the author and publisher will be entirely irrelevant to the price-setting process. In first case, prices will generate revenue far in excess of the sunk costs; in the second case, prices will fail to recoup any of the sunk costs. The key factor is the difference in value, as reflected in the market outcome.

Q. Are you arguing that the Commission should set gas delivery rates in the exact same way competitive markets determine the price of novels, or beef and hides or Cadillac and Chevrolet automobiles?

A. No. The Commission has considerable flexibility in deciding how to price EnergyNorth's services, and I am not suggesting it should follow precisely the same pattern that explains how joint and sunk costs are recovered in competitive markets. However, the patterns observed in competitive markets are highly relevant and instructive, and they should be evaluated by the Commission, along with other considerations. To give just one example, it might be argued that prices should be relatively uniform, for reasons of simplicity, or administrative convenience, or to ensure consistency with the results of a particular cost study. However, in competitive markets joint and common costs are never recovered on a purely uniform basis, since this would be sub-optimal. As a general rule, market-based prices do not recover an identical monthly dollar amount from each individual customer toward recovery of fixed or joint costs, nor do they typically result in a uniform percentage markup above the marginal cost of producing each product.

When large differences exist in the benefits received from customers of different sizes or types, competitive prices will generally deviate from uniformity in order to take into account those differences. For instance, Ford produces multiple different car models in a common production process. By using the same transmission and other key components on more than one model, Ford can spread the recovery of the fixed costs of engineering and design, and the fixed costs of machine tooling for those common components across multiple different cars. This allows it to further exploit economies of scale and scope. As a result, a disproportionate share of Ford's profits is generated by higher-end models which are loaded up with accessories and luxury packages that are highly valued by some customers. Those customers are willing to pay a much higher price for cars with these enhancements (well in excess of the marginal cost of adding these enhancements). Consistent with economic theory, these customers provide a much larger contribution toward Ford's sunk, joint and common costs. Other customers, who don't value these features as highly, or who cannot afford them, purchase lower-end models which provide a much smaller contribution toward Ford's joint and common costs.

While Ford's motive in marking up prices for different car models by different amounts is a desire to maximize profits, the end result is beneficial to society as a whole. Differential markups enable lower income consumers to purchase newer, more reliable transportation, and it helps Ford produce more cars and employ more people than if it applied a uniform markup above marginal cost on each car model. Applying different markups to different models allows Ford to sell more cars more profitably, including sales made to customers who perceive relatively little benefit from owning a new car, and customers who can only afford a stripped-down version of the basic product – one that most consumers wouldn't be satisfied with.

One way of thinking about this competitive pricing process is to recognize that optimal prices involve the interaction of both supply and demand – like two blades of a scissor which cut paper much more effectively than a single blade on its own. The key takeaway is that competitive prices take into account more than just differences in marginal cost. The demand side of the equation (differences in the benefits or value received by different types and sizes of customers), are also important.

Similarly, the Commission can (and should) use its discretion to decide how far specific prices should be set above marginal cost. More specifically, I recommend reducing EnergyNorth's customer charges, and increasing the volumetric rates, thereby improving the alignment with differences in the value received by large and small customers, and better advancing important public policy goals, including fairness and encouragement of economic efficiency and energy conservation.

IV. THE COMPANY'S MARGINAL COST STUDY

Q. What role did the marginal cost study play in the Company's pricing proposals?

A. This study is virtually the only evidence offered by EnergyNorth to support its proposed revenue allocation and rate design in this proceeding. The justification for placing so much emphasis on this study was explained as follows:

> A well-established principle of economic theory is that the price of a good that is sold in a perfectly competitive market will be set at the marginal cost to produce that good. It is a further well- established principle of economic theory that the best allocation of resources will occur, and the best consumption decisions will be made, in an economy in which the prices of goods are set at marginal costs.
>
> It has been the Commission's rate-design policy and precedent since the mid-1980s to apply the concepts of marginal cost pricing in a rate case (a) to determine the share of total rate case revenue requirement for which each rate class is responsible, and (b) to set base distribution rates in order to promote appropriate price signals and, therefore, proper energy consumption decisions. The basis for the Company's current allocation of revenue requirement to classes, rate design, and current rate classifications was approved by the Commission in Order No. 23,675 (Apr. 5, 2001) in the Company's 2000 revenue neutral rate design proceeding, Docket No. DG 00-063.[17]

17 Direct Testimony of Melissa F. Bartos, Pages 2-3.

Q. Have you reviewed Order No. 23,675?

A. Yes. A marginal cost study was filed in that case (and in subsequent cases) and was accepted in the settlement agreement that resolved that proceeding. Based upon my reading of the order, the cost study does not seem to have been a primary focus of attention. Rather than extensively debating details of the marginal cost study, the parties seem to have primarily focused on specific rate issues, including the level of customer charges, the introduction of a load factor-based rate structure and Cost of Gas clause, and an effort to reduce rates charged Commercial and Industrial customers without unduly burdening Residential customers.

The Company explained it wanted to move toward "cost-based rates" and facilitate increased retail competition, but the primary focus of the parties seems to have been on the proposed rate changes. It isn't clear how carefully the parties examined the inner workings of the cost study that was submitted in that proceeding, but the details of the study were not pivotal to the settlement agreement, nor was there any discussion of the inner workings of the study in the Commission's order. Furthermore, OCA and other parties expressly reserved the right to argue for a different cost of service methodology in future proceedings.

Q. Did the Commission discuss or endorse the details of the marginal cost study in its order?

A. No. The marginal cost results are briefly mentioned in the order, and they undoubtedly played a role in the Commission's decision, but there is no indication the details of the underlying methodology was being endorsed.

> We note that the target marginal cost-based class revenue served as a guide in establishing the Settlement rates. Had the Settling Parties and Staff fully reflected the results of the marginal cost studies in the ratemaking process the rate increase for the Residential classes would likely exceed those that were proposed. For example, the Settling Parties and Staff recommended monthly customer charges of $10.00 and $7.00 for Residential Heat and Residential Non-heating customers respectively... considerably short of the $22-23 shown in KeySpan's marginal cost study. ...
>
> Further, while a 6% increase in the revenue requirements for the Residential Heating Class and a 13% increase for the Residential Non-Heating class appear substantial, one must also consider the monthly bill impact and the fact that KeySpan custoemrs have not had a base rate increase since April 1, 1993. ...
>
> The statutory standards ... do not require that the Commission determine the outcome using any specific methodology, so long as the result is consistent with the "public interest" and the rates are "just and reasonable." ...
>
> We believe that an "end result" review is particularly applicable to the consideration of settlement agreements, which, by their nature, often require parties to compromise positions and principles in order to reach an acceptable outcome. Thus, while the Commission ... must condut its own independent review in order to ensurethat the "public interest" and "just and reasonable" standards have been met, it may do so without reliance upon any particular theory or methodology.[18]

Q. Can you briefly summarize your overall reaction to the cost study in this proceeding?

A. While there are several aspects of the Company's cost study I disagree with, the most fundamental problem is the severe lack of consistency with economic theory. These

18 New Hampshire Public Utilities Commission, Order No. 23,675, April 5, 2001, pages 22-24.

inconsistencies include a failure to draw meaningful and appropriate distinctions between fixed or sunk costs and variable costs, and a failure to maintain these distinctions in an internally consistent, logical manner. The effect of these inconsistencies is to increase the customer-related cost estimates relative to the demand-related cost estimates.

This problem is further compounded by the questionable manner in which some of the statistical equations were developed, which involved an unacceptably high degree of "data mining," an excessive reliance on dummy variables, and the lack of theoretical support for the dummy variables. The combined impact of the theoretical and statistical problems are so severe, they completely invalidate any conclusions that might otherwise be drawn from the study.

A. Inconsistencies with economic theory

Q. Did the Company adopt a clear, consistent definition of planning horizon or "run" that it studied?

A. No. Ms. Bartos never explicitly states what "run" or planning horizon she intended to study, and neither the word "run" nor the phrase "planning horizon" appear anywhere in her testimony. I did find the phrase "Long-Run Unit Costs" used as a label on line 1 of Attachment MFB-8, page 1, and this cryptic reference suggest the intent was to study some sort of long-run costs, not short-run costs.

As I indicated earlier in my testimony, the planning horizon or "run" is crucially important. Both as a theoretical matter and as an empirical matter, when looking at a well-designed marginal cost study for a gas utility, one can expect to see lower low cost estimates the shorter the planning horizon that is evaluated, since the shorter the "run" the greater the extent to which sunk costs will dominate the calculations (assuming they are correctly developed). Conversely, when looking at long-run studies, one can expect to see higher marginal or incremental cost estimates – especially if a "scorched earth" or "extreme long-run" scenario is modeled, which assumes there are very few, or no, sunk costs.

When the "run" is not clearly and consistently stated, or a mixture of different planning assumptions or time-horizons are used in different aspects of a marginal or incremental cost study, one can expect the results to be highly dependent upon specific assumptions and details concerning what is treated as fixed and what is treated as variable. This was the situation I encountered when examining the Company's study in this case. The Company completely ignored the fact that a service line, regulator and meter have already been installed at most building along the routes where EnergyNorth has distribution mains in New Hampshire. The cost of these items is almost always sunk and unavoidable once they are installed. In the case of a typical existing building, which is already connected to the system, if the building sits vacant for a while, the cost will not be reduced just because the service line isn't being used. If a new owner or tenant moves into the building and requests gas service, the Company will add another customer to its rolls, but the cost of these facilities will not increase. If the customer then remains on the system, the cost will not change. Finally, if the customer subsequently leaves the system, the cost will not decline.

This sunk cost problem was completely ignored when the Company developed its cost estimates for service lines, regulators and meters. Unlike the statistical approach it used in studying other costs, the Company adopted a "scorched earth" approach to cost modeling, which is entirely based on engineering cost estimates, and gave no consideration to the extent to which customer-related costs are actually at "the margin." In the context of EnergyNorth's system, this approach is only logically consistent with an extreme long-run planning horizon. A far less extreme version of the long-run was used in the rest of the study, where a statistical approach was used to estimate the degree to which costs are increasing due to main reinforcements and main extensions.

The explanation provided by Ms. Bartos glossed over these inconsistencies, but this brief passage provides a good entry point for explaining them in greater detail:

> I prepared calculations and analyses to estimate the marginal distribution function-related costs that the Company would incur to serve (a) additional demand when the Company is experiencing design day conditions, and (b) additional customers.

At least two things are noteworthy about this brief explanation. First, she exclusively refers to "additional" demand or customers, meaning the increases in total cost that potentially would occur if there were to be an increase in design day demand or an increase in the number of customers. She makes no mention of how much costs decline when customers conserve energy or reduce their design day demand, or how much total costs decline when an existing customer leaves the system. Second, she separates her calculations and analyses into two broad groups, corresponding to the pricing distinction between volumetric rates (which are supported by her cost estimates for "additional demand when the Company is experiencing design day conditions" and customer charges (which are supported by her cost estimates for "additional customers."

Upon further investigation, I confirmed the study is exclusively focused on how costs change when the volume of output increases. No attempt was made to examine how much costs decrease when an existing customer leaves the system, or when an existing customer reduces their energy usage or design day peak demand. This failure to consider the rate of change in the downward direction compounded some other flaws I found in the study. This may also help explain why the Company didn't notice any of the problems with adopting a purely hypothetical "scorched earth" approach to modeling the cost of service lines, regulators and meters. If did not examine how much costs decline when a customer leaves the system (e.g. when a building becomes vacant or a customer switches to a geothermal heat pump). Thus, it completely ignored the "ratchet" phenomenon – the fact that investments in services, regulators and meters are sunk once they are installed at a specific building. They do not increase or decrease with changes in the number of customers receiving gas service at that location.

Q. Why is the change in total cost as output decreases relevant?

A. In part, it is relevant because the study results have been labeled as "marginal cost" estimates. Since the term "marginal cost" is taken from the economic literature, the validity of the Company's cost estimates and underlying assumptions, should be judged in that context. Under the simplest conditions considered in economics, where he cost function is smooth and continuous, and cost is the same whether it is measured by how much total cost increases as output increases by an extremely small amount, or how much total cost decreases as output decreases by an extremely small amount. If this equivalence cannot be confirmed, it should be taken as an indication that may be flaws in the modeling approach, or there are complexities that need to be carefully evaluated and resolved.

These complexities arise when the cost function is not smooth and continuous, because of lumpiness, “ratchet” effects, or other complications. Where those complications are known to exist (or are encountered during the modeling process), they need to be dealt with appropriately. A good starting point is to evaluate how much costs change when output is varied by different amounts, or in different directions, or in different geographic locations. To the extent the cost estimates vary significantly, it becomes necessary to decide on the most appropriate solution. Should these disparate results be averaged? Should they be blended, with different weights given to different cost estimates? Or, should different prices be developed which are applicable to the different situations which give rise to different costs?

From my perspective as an economist, the least desirable and least logical solution is to simply ignore the problem. In the case of the service lines, the effect of ignoring the sunk cost problem is to effectively treat every customer as if they were “at the margin” – equivalent to the relatively rate situation facing a potential customer that is thinking about constructing a new building and they need to decide whether to use natural gas. Since this situation is not the one confronting most people most of the time, it obviously deserves less weight than the more common situation where someone is occupying an existing building, or thinking about moving into an existing building, with an existing connection to EnergyNorth's distribution system.

For most customers and potential customers, the situation where the service line doesn't exist is a purely imaginary or hypothetical scenario with little relevance. The decisions most people will make in response to the prices set in this proceeding will not involve any action or potential action that puts the service line, regulator and meter at the "margin" of decision-making. In terms of economic efficiency and public policy, the most relevant question for designing rates is how much costs will actually increase or decrease at the margin when someone decides whether to use gas, or how much gas to use, while occupying a building that is already connected to the system. For those customers, the cost of the service, regulator and meter will typically be a sunk cost, which is irrelevant from the perspective of optimal pricing policy.

One exception, where the cost is not fixed or sunk, occurs when someone builds a new home or business. Another exception occurs when gas service is being extended for the first time to their neighborhood, and they decide whether to connect to the system. Since those exceptions are less common than the situation where the building is already connected to the system, the overall system-wide level of long-run marginal costs should give much more weight to the typical situation, where these costs are sunk.

Q. Is the proportion of sunk costs uniform throughout the system?

A. No. Sunk costs are most prevalent where facilities are used by just one or two customers, and they are less prevalent where facilities are shared by hundreds or even thousands of customers. The logical connection between the degree of cost-sharing and sunk costs is straightforward. Recall that long-run marginal cost is the rate of change in total costs that occurs in a planning horizon where many capital costs are potentially variable. The more customers that share a particular piece of equipment, the greater the likelihood that increased usage by any one of those customers can create "congestion costs" or opportunity costs which impact hundreds or thousands of other customers. Congestion occurs whenever the demand placed on shared equipment begins to approach its design capacity. Conceptually, this is somewhat analogous to a bottleneck in an assembly line, which impacts the productivity of every worker and every piece of equipment that is downstream from the congestion point. When congestion begins to occur within a widely shared part of the system, expanded usage by even a single customer can adversely affect the safety and reliability of service to other customers on the system. When congestion begins to become a concern, the marginal cost begins to increase, based upon the increased probability of encountering problems which would adversely impact the safety and reliability of service to many different customers. If insufficient capacity exists to fully accommodate fluctuations in and potential growth in demand, the marginal cost curve will turn sharply vertical, as the probability of unsafe conditions or inadequate operating pressure begins to escalate.

Because reliable utility service is vitally important to most customers, the cost to customers, and society, of being unable to supply gas when it is needed can be extremely large. This is analogous to the risk of a tornado, or hurricane, or fire, where a very large problem is multiplied by a very small probability – which explains why people pay for insurance even though there is very little risk they will encounter a problem during any one hour or day. The probability-based costs associated with potential system congestion or inadequate capacity become part of the marginal cost to society associated with providing gas service to every customer who can potentially be affected by the problem. This logically follows because an increase in peak usage by any customer downstream from the point of congestion could trigger problems for many other customers. Similarly, a reduction in usage by any downstream customer can help alleviate the problem, reducing the risk of a problem. Under those conditions, the reduction in usage by any one customer will reduce the marginal cost of serving all of the other customers on that part of the system, and vice versa.

These societal costs are one of the reasons regulations exist which require utilities to provide safe and reliable service. Even if this were not required, it would be in the best interest of the gas company to install ample capacity wherever it might be needed, in order to reduce the potential for future congestion problems. However, building adequate reserve margins throughout the system is costly, and this should be considered when estimating the long-run marginal cost of meeting design day demand. These congestion-related societal costs are highly relevant in the context of distribution mains and other widely shared parts of the system, and of much less relevance to a service line that only impacts a few customers.

Q. How are capital costs handled in a valid long-run marginal cost study?

A. Basically, a valid long-run marginal cost study considers the rate of change in the total cost function as the size, design and capacity of the capital investment is varied and optimized, along with corresponding variations in operating costs. This optimization analysis is supposed to be performed in the context of a long-run "planning horizon" which is not excessively tied to, or unduly constrained by, limitations and characteristics of the existing system. In other words, rather than focusing on the "worst case" scenario of what would happen if problems arose and no effort were made to resolve them by making new investments, the assumption in a long-run planning horizon is that new investments are made that avoid these problems, taking into account growth and replacement needs over the long-run.

As I indicated earlier, an appropriate long-run planning horizon for EnergyNorth would correspond to the degree to which capital investments can potentially be varied over a typical 10 to 20 year planning horizon. Over this time period, EnergyNorth's distribution mains would not be classified as entirely fixed or sunk, but instead should be treated as being variable to a substantial degree. For instance, over this time period new mains will need to be installed along some routes, where older, existing mains are nearing the end of their useful life, or becoming unacceptably leak-prone. This impacts the long-run marginal cost of all of the customers sharing those facilities.

Similarly, over a 10 to 20 year time period, even if system-wide average consumption is stable, there will be pockets of growth in some areas, and declining usage in other areas. Accordingly, congestion will likely arise in some areas which can be resolved by replacing the existing mains with larger ones, reinforcing the route with a second main, or upgrading parts of the system to operate at higher pressures. None of these options is entirely cost-free, of course, and the costs of the optimal solution will be reflected in the marginal cost of serving every customer using those mains.

EnergyNorth has the opportunity to optimize many capital-related decisions over a 10 to 20 year planning horizon. For instance, it can decide whether to reinforce, replace or retire some of its existing mains, and it can select the optimal size of each newly installed or reinforced main over its economic life. For locations where capital investments can be optimized, the cost of installing, reinforcing or replacing mains may be relatively high (compared to the cost of existing mains) on a per-linear foot basis, due to inflation and other factors, like the difficulties involved with installing new mains in areas where older mains, water lines and other infrastructure already exists.

Of course, in a location where the existing main is relatively new, it has many decades of useful life remaining, and the route has ample capacity to meet all foreseeable demand for that entire time period, the capital-related costs of the main may appropriately be classified as fixed or sunk. In those locations, the capital-related cost of distribution mains may be very low, especially if the main cannot be adjusted or optimized to serve some other purpose over the relevant planning horizon. Accordingly, an analysis of the overall system-wide level of long-run marginal costs of distribution mains will represent a composite of relatively high costs in some locations and relatively low costs in other locations.

B. Flaws in the Statistical Cost Estimates

Q. What approach did the Company use to estimate the marginal cost of distribution mains?

A. Unlike its approach to the cost of facilities at or near the customer's premises, the Company used a statistical approach to estimating the marginal cost of other parts of the system. The general approach is captured in the following passage in the direct testimony of Melissa Bartos:

> I asked the Company to prepare an engineering study of forecasted system reinforcement projects that the Company would be required to construct from 2016 to 2026 to meet the Company’s projected design day demand during that period. The engineering study that I asked the Company to

> prepare is different from the Company's actual distribution asset plan, which takes into account (a) projects that will be required to meet projected load growth, (b) projects that are included in the Company's Cast Iron Bare Steel ("CIBS") replacement program, and (c) other distribution replacement and relocation plans. The Company's distribution asset plan is different from the projections that I requested because the actual asset plan may combine a reinforcement project with a CIBS replacement project or other replacement or relocation projects, which is likely to affect the timing and location of reinforcement projects.[19]

This is virtually the entirety of the conceptual or theoretical support offered for this approach. The remainder of the explanation is focused on the specific data that was used, and the statistical approach that was used to analyze this data. No explanation was offered concerning the portion of the overall system-wide total cost of mains that was effectively being treated as fixed or sunk, and no explanation was given for why the Company used a fundamentally different approach to estimate the cost of services, regulators and meters.

While the offered explanation is rather cryptic, when it is considered in conjunction with the Company's work papers, it is clear that some of the cost of distribution mains is implicitly being treated as fixed or sunk. In effect, the cost estimates developed by the Company represent a composite of relatively high costs for mains in locations where growth is occurring, or mains need to be replaced or relocated, and relatively low (or zero) costs for mains in the remaining locations. While I don't find this approach objectionable in principal, I am troubled by some aspects of the actual calculations.

19 Direct Testimony of Melissa F. Bartos, Pages 9-10.

Q. Do you have any concerns regarding the statistical approach used by the Company?

A. Yes. There are two closely related problems which obliterate the validity of the statistical results. The first major problem is that some potentially important explanatory variables were not evaluated. Because variables that are potentially important (on theoretical grounds) were never evaluated, it is difficult or impossible to judge the statistical validity of the other variables that were included in the analysis. The second major problem is closely related: data mining was used to evaluate far too many "dummy" variables – including variables for which no "a priori" theoretical basis exists to justify testing them. Both problems are very serious, and make it impossible to have any confidence in the validity of the statistical results.

Q. Can you briefly explain the statistical approach used by the Company to analyze the cost of distribution mains?

A. Yes. A single statistical tool – called linear regression – was used for to study the cost of main reinforcements and extensions.

> I prepared a regression analysis to estimate the statistical relationship between the projected cost of system reinforcement projects and projected design day demand. The regression equation that I estimated is provided in Attachment MFB-1, page 3.

> I prepared a regression analysis to estimate the statistical relationship between the cost of main extensions and design day demand, based on the historical data from 1989 to 2016. The regression results are summarized in Attachment MFB-1, page 4.[20]

20 Ibid, page 10.

Linear regression is a popular statistical technique that is frequently used to model the relationship between a scalar dependent variable (typically referred to as "Y") and one or more explanatory variables (also referred to as independent variables) which are typically denoted as "X" (or X1, X2, X3...). In this context, the dependent variable is the cost of installing distribution mains, and the explanatory variables are the factors which help explain why those costs are high in some years, or some locations, and low in other years, or other locations.

Q. Why is it a problem to exclude important explanatory variables from a regression analysis?

A. Linear regression works best when adequate data is available that captures every significant variable that helps explain, or "cause" fluctuations in the dependent variable. In the case of distribution mains, that suggests it would be preferable, if at all possible, to obtain and use data concerning any potentially important explanatory variable that might be varying from year to year, or location to location. For instance, it would be helpful to obtain data from work orders, engineering records, or other internal sources that indicates the extent to which mains were installed under streets (which is potentially more costly and time consuming, and requires restoration of the paving when completed). Similarly, it would be helpful to obtain data that could be used to evaluate the extent to which mains were being installed in urban areas, compared to less congested rural areas. Similarly, it would be preferable to obtain data concerning the extent to which rocky conditions, or solid bedrook, was encountered on particular jobs, or along particular routes. Sound theory and logic suggests variations in these conditions could easily have a significant impact on the cost of mains installed in one year, or one location, compared to the cost of mains installed in different locations and different years.

If reliable data is not available for important explanatory variables, then the results of the linear regression will automatically impute the impact of those missing variables onto whatever variables are included in the analysis. For example, if the cost of installing mains in year one happens to be high and the cost in year two happens to be low, the goal of the statistical analysis will be to "explain" how much of the variation from one year to the next is attributable to the explanatory variables that are included in the regression analysis. However, if variables are missing, the regression will not account for, or "hold constant" those missing variables. Instead, the statistical software will attribute the fluctuation in costs to whatever explanatory variables happen to be used in the regression equation.

Sometimes, when needed variables are missing, the result will be a poor statistical "fit" – the regression will only explain a small portion of the observed variation in the dependent variable. However, this is not always the case. Sometimes instead, the result will be a fairly good statistical "fit" but the result will be inaccurate and misleading. For example, consider what would happen if a missing variable, like the amount of bedrock that is encountered, happens to be much larger in year one than in year two. If it also happens to be the case – by pure coincidence – that the capacity of the mains installed in year one happens to be larger than the capacity installed in year two, the statistical software will have no way of knowing what portion of the cost fluctuation is caused by differences in the amount of bedrock. Instead, it may attribute the entire difference in cost to the difference in design capacity, while in reality only a portion of the cost difference is actually attributable to difference in capacity. Succinctly stated, when data for important variables is missing, the regression results will not be reliable, imputing some of the cost fluctuations that are actually caused by missing variables to whatever independent variables are included in the regression.

Q. Did the Company acknowledge that there are explanatory variables that were not accounted for in its statistical analysis?

A. Yes. For example, the Company was asked in discovery to explain what other explanatory variables could impact main extension investments. It responded:

> There are many variables that could impact main extension investments, including: terrain, length of pipe installed, urban/rural area, type of pipe installed, diameter of pipe installed, paving requirements, and traffic detail requirements.[21]

Yet, none of these variables were statistically evaluated. The only justifications offered for excluding these variables from the analysis were "practical" concerns that potentially might have made it difficult to collect the data needed to evaluate some of these variables, and this claim:

> In addition, the purpose of this analysis is to identify the relationship between main extension costs and design day demand on an annual basis, not to predict main extension costs for individual projects.[22]

However, if these variables may be needed to accurately predict the cost of individual projects, they may also be needed to accurately predict the cost of projects that

21 Response to Request No. OCA 1-56 (c).
22 Ibid.

will occur in future years (since the mix of future main extension projects will not be identical to the particular mix that was observed in the historical time period).

Q. Can you explain your concern with respect to dummy variables?

A. Yes. Although Ms. Bartos doesn't mention the words "dummy variable" in her testimony, she used a lot of them. Looking at the final statistical equations used in the marginal cost study, I found an interactive dummy variable for the years 2018-2026 on Attachment MFB-1, page 3, a dummy variable for the year 2000, two different dummy variables for the years 2012 to 2016, and a dummy variable for 2002 to 2004 just on Attachment MFB-3, page 4, alone. I also found two different dummy variables on Attachment MFB-4, and an astounding 10 different dummy variables on Attachment MFB-5 page 1. I found additional dummy variables scattered throughout the other pages of the marginal cost study, including six dummy variables on Attachment MFB-5 page 3, five dummy variables on Attachment MFB-6 page 1, four dummy variables on Attachment MFB-6 page 2, four dummy variables on Attachment MFB-6 page 3 and one more dummy variable on Attachment MFB-6 page 4.

The sheer number of dummy variables that were used by Ms. Bartos calls into question the plausibility and reliability of her statistical results. From my perspective as an economist, dummy variables can be thought of as disappointing second-best solution that we sometimes resort to, because of the inadequacies of our data. The main problem with dummy variables is that they don't really "explain" anything. They can improve the statistical fit, helping to overcome weaknesses in the data, but they don't actually provide any additional insight into the underlying factual relationships that explain the phenomena being studied. In this instance, they don't help us identify and understand the important factors which cause a particular level of total cost to be incurred in one year and a different level of total cost to be incurred in a different year. In turn, since we don't know why total cost differs between two years, we can't accurately estimate marginal cost (how much of the variation relates to differences in the volume of output). Stated another way, if we aren't gaining a true understanding of what caused the level of costs during specific years, we aren't developing a reliable tool for predicting what level of total cost will be incurred during future years, or how much that cost will vary as a function of differences in demand.

When dummy variables are arbitrarily used to improve the statistical “fit” we don't know what would happen if the equation were applied to a different utility during those same years, or if it were applied to the costs incurred by the same utility during an entirely different time period, or in a different jurisdiction. In this case, these inherent weaknesses were greatly exacerbated by five additional, interrelated problems:

First, Ms. Bartos considered and rejected numerous additional dummy variables, including ones that were ultimately rejected, and were not specifically disclosed in the marginal cost study documentation. The only dummy variables that were reported were those she ultimately chose to include in the final equation, because they “improved” the statistical fit.

Second, the use of dummy variables exacerbated the problem I described earlier with respect to what happens when important explanatory variables are excluded from a regression analysis. Adding dummy variables makes that problem worse because it increases the risk of inadvertently imputing cost fluctuations caused by missing variables to one of the independent variables in final regression equation. The more dummy variables that are tested, the greater the chance some of them will appear to be significant, yet they are merely picking up some of the unexplained cost fluctuations that are attributable to the missing explanatory variables.

Third, all of the dummy variables were evaluated on a purely statistical or "end result" basis. No *a priori* basis existed for testing many of these variables, and none of variables included in the final equations is justified on the basis of sound theoretical reasoning. Absent a sound, independent theoretical justifying a dummy variable, there is no reason to assume the variable is anything more than a statistical artifact of the particular data set that was used in developing the equation. The closest Ms. Bartos comes to providing a theoretical basis for her dummy variables was to note that ownership of the Company changed several times during the historical time period used in her analysis.

> I also tested each equation to look for "structural shifts," which are changes in the relationship between the Cost Variable and Cost Driver variable starting in a specific year and continuing for a number of years. I specifically looked for structural shifts that might have been related to the acquisition of EnergyNorth by KeySpan in 2000, the later acquisition of KeySpan by National Grid in 2007, and the acquisition of EnergyNorth by Liberty in 2012.[23]

However, Ms. Bartos had no basis in theory to anticipate whether costs would increase or decrease after any particular change in ownership. If they happened to increase or decrease around the same time as the change in ownership, she had no way of

23 Direct Testimony of Melissa F. Bartos, Page 5.

determining whether the change in costs was related to the change in ownership or purely coincidental. Conceivably, if costs increased after a change in ownership, it might be attributable to a greater corporate desire to build up the rate base. Conversely, if costs decreased after a change in ownership, it could conceivably be due to a greater commitment to cost control by the new management team.

The problem with not having sufficient *a prior* justification for using these dummy variables was compounded by a failure to collect additional evidence to evaluate what was causing costs to be different during these particular time periods. Ms. Bartos apparently made no effort to determine whether observed changes in costs that occurred around the time of an ownership change were attributable to something related to the ownership change, or something else entirely, like a larger or smaller fraction of new mains being installed in areas with a lot of bedrock, or in municipalities with costly traffic detail requirements.

Fourth, Ms. Bartos did not limit her exploration of dummy variables to specific time periods associated with each change in ownership. Instead, she explored numerous other time periods that were just loosely associated with the changes in ownership:

> However, I did not limit the potential structural shifts to these years. If I determined that a Cost Variable may have a structural shift, I tested additional regression equations that allowed the slope and/or intercept terms to be different for the time periods before and after the time of the potential structural shift.[24]

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24 Ibid, Page 6.

Whatever the intent, this procedure was effectively a form of "data mining" and as a result, the statistical equation were driven by the data set, rather than using theory to develop the variables and using the data set to test the theory.

Fifth, Ms. Bartos arbitrarily assumed that the statistical results for the most recent time period would be applicable to future years. This is not a valid assumption given the approach she used.

> If a structural shift was found to be significant, I used the slope associated with the latest (i.e., most recent) time period as the marginal cost estimate because, all else being equal, costs from the most recent time period are expected to be more representative of costs in the future.[25]

In fact, the change in costs that occurred during the most recent few years might be attributable to some unique combination of unknown factors that happened to occur during those years – something entirely unrelated to the change in ownership, but some other phenomena that may or may not persist in future years. Accordingly, her equations do not provide us with any confidence that they can meaningfully predict what level of total costs will be incurred during future years, or how much those costs will vary at the margin. This follows directly from the fact that we have no way of predicting whether the unique combination of unknown causal factors that occurred during recent past will also occur to the same extent, and in the same combination, during future years. Especially given the large number of different dummy variables she considered and used, it is very likely that each of the time periods and sub-periods she studied has a unique combination of causal factors that happened to occur during those particular years.

25 Ibid.

Future years will have their own unique combination of causal factors, which will not precisely replicate that of the most recent historical period, or any other specific prior period.

By failing to collect enough data related to the underlying causal factors that actually explain fluctuations in cost from year to year, and by experimenting with different dummy variables to find ones that closely conform to those fluctuations, it becomes impossible to know whether, or to what extent, causal conditions in future years will resemble those that existed in any particular past time period. We have no statistical or theoretical basis for knowing whether a phenomena that occurred during the years 2002-2004 will also occur at some point in the future, and if so to what extent it will affect the long-run planning horizon being studied. Similarly, there is no way of knowing whether a phenomena that occurred during the years 2012-2016 subsequently ended in 2017, or whether it continued through the following year, but will end shortly thereafter, and therefore has little or no relevance to the long-run planning horizon.

Dummy variables allow the statistical equation to adapt to specific artifacts of the data that occurred during past years, but they inherently detract from our ability to use the equation to understand or predict what will happen in future years, since we have no way of knowing whether the phenomena that occurred during those years will, or will not, occur in the future, or to what extent those particular phenomena will occur in any particular future year.

Q. You also mentioned data mining. Can you please explain this problem?

A. Yes. Data mining is a term that was coined in the 1990's to describe the process of using computer software to search through a large data sets looking for patterns that are not readily apparent from simply looking at the data. As computers and data storage have become cheaper, it has become practical to assemble extremely large data sets, and companies have found it feasible and convenient to use automated process to search through their data looking for patterns that might provide them with useful insights. A leading provider of Analytics Software explained the benefits this way:

> Retailers, banks, manufacturers, telecommunications providers and insurers, among others, are using data mining to discover relationships among everything from pricing, promotions and demographics to how the economy, risk, competition and social media are affecting their business models, revenues, operations and customer relationships.[26]

In a blog post published by a major statistical software provider, data mining was described this way:

> Data mining uses algorithms to explore correlations in data sets. An automated procedure sorts through large numbers of variables and includes them in the model based on statistical significance alone. No thought is given to whether the variables and the signs and magnitudes of their coefficients make theoretical sense.
>
> We tend to think of data mining in the context of big data, with its huge databases and servers stuffed with information. However, it can also occur on the smaller scale of a research study.[27]

26 SAS, "Data Mining, What it is and why it matters" https://www.sas.com/en_us/insights/analytics/data-mining.html

27 The Mintab Blog, September 21, 2016, "Problems Using Data Mining to Build Regression Models," http://blog.minitab.com/blog/adventures-in-statistics-2/problems-using-data-mining-to-build-regression-models

The author goes on to show how dangerous data mining can be when it is used in developing a regression model.

> My first order of business is to prove to you that data mining can have severe problems.
>
> ...what could possibly be wrong with this approach? Data mining can produce deceptive results. The statistics and graph all look good but these results are based on entirely random data with absolutely no real effects. Our regression model suggests that random data explain other random data even though that's impossible. Everything looks great but we have a lousy model.[28]

Ms. Bartos used a process which closely matches the one this author warns against. She applied data mining to a small data set, experimenting with a large number of different dummy variables before settling on a particular set of dummy variables that happened to give her a particularly good statistical "fit." She then applied this model to the same data set she used to select the variables, rather than testing the resulting equation on an independent data set.

The reason why this process is inappropriate is well explained by the author, so I will quote at length from his article:

> The problem with data mining is that you fit many different models, trying lots of different variables, and you pick your final model based mainly on statistical significance, rather than being guided by theory.
>
> What's wrong with that approach? The problem is that every statistical test you perform has a chance of a false positive. A false positive in this context means that the p-value is statistically significant but there really is no relationship between the variables at the population level. If

28 Ibid.

> you set the significance level at 0.05, you can expect that in 5% of the cases where the null hypothesis is true, you'll have a false positive.
>
> Because of this false positive rate, if you analyze many different models with many different variables you will inevitably find false positives. And if you're guided mainly by statistical significance, you'll leave the false positives in your model. If you keep going with this approach, you'll fill your model with these false positives. That's exactly what happened in our example. ...
>
> As we've seen, data mining problems can be hard to detect. The numeric results and graph all look great. However, these results don't represent true relationships but instead are chance correlations that are bound to occur with enough opportunities. ...
>
> Data mining can have a role in the exploratory stages of an analysis. However, for all variables that you identify through data mining, you should perform a confirmation study using newly collected to data to verify the relationships in the new sample. ...
>
> An alternative to data mining is to use theory as a guide in terms of both the models you fit and the evaluation of your results. Look at what others have done and incorporate those findings when building your model. Before beginning the regression analysis, develop an idea of what the important variables are, along with their expected relationships, coefficient signs, and effect magnitudes.
>
> Building on the results of others makes it easier both to collect the correct data and to specify the best regression model without the need for data mining. The difference is the process by which you fit and evaluate the models. When you're guided by theory, you reduce the number of models you fit and you assess properties beyond just statistical significance.[29]

29 The Mintab Blog, October 19, 2016, "Problems Using Data Mining to Build Regression Models, Part Two," http://blog.minitab.com/blog/adventures-in-statistics-2/problems-using-data-mining-to-build-regression-models-part-two

Q. How serious are these problems?

A. The problems are very significant, but it is not easy to quantify the impact. To provide an order of magnitude indication of the seriousness of the problems, I will focus on a single example – main extensions. The Company's marginal cost estimate for main extensions was developed as follows:

> I prepared a regression analysis to estimate the statistical relationship between the cost of main extensions and design day demand, based on the historical data from 1989 to 2016. The regression results are summarized in Attachment MFB-1, page 4.[30]

Ms. Bartos summarized the result of her statistical analysis in Table 3, included in her direct testimony.[31]

Table 3: Marginal Cost of Distribution Capacity-related Plant Additions

Marginal Plant Additions Component	$ per Dth	Source (Attachment)
Production in lieu of Reinforcement	$56.05	MFB-1 page 1
Reinforcement	$63.33	MFB-1 page 3
Extension	$505.18	MFB-1 page 4
Total	$624.56	

Turning to Attachment MFB-1, page 4, we find the estimated marginal cost of main extensions ($505.18) is extremely dependent on her assumption that the equation for the four year period 2012-2016 is more appropriate to use in the long-run planning horizon. This documentation clearly shows that if one simply assumes the results for 2012-2016 are attributable to unknown unique factors occurring in those particular years,

30 Direct Testimony of Melissa F. Bartos, Page 10.
31 Ibid, Page 11.

and the estimated of costs prior to 2012 are also applicable to years after 2016, the marginal cost estimate changes from $505.18 to $1,672.55.[32]

For the period prior to 2012:

∂ Distribution Plant Additions for Main Extensions / ∂ Design Day Demand = $1,672.54 per Dth

For the period 2012 and beyond:

∂ Distribution Plant Additions for Main Extensions / ∂ Design Day Demand = $505.18 per Dth

No evidentiary support was offered for this assumption, which is not well-grounded in economic theory or practice. Arguably, it is more reasonable to assume the dummy variable captures phenomena that are unique to 2012-2016, in which case it would have no relevance to any other years. Under that assumption, the equation for the 23 year period prior to 2012 would be used for the long-run cost estimate. This has the advantage of focusing on more years of data, and it would better acknowledge that we have no information explaining why those four years had different costs than the other years. Absent convincing evidence that the unique factors applicable to those years will be present to the same degree in future years, there is absolutely no basis for using this dummy variable to estimate marginal costs for a long-run planning horizon.

One more point worth noting: while the most recent change in corporate ownership took place in 2012, I find it hard to believe the new owners suddenly discovered or pointed out a way to slash the cost of main extensions. I find it rather far-fetched to think the new owners found a way to slash reduce cost of main extensions from $1,672.55 per Dth to just $505.18 per Dth on a permanent basis. A far more plausible explanation is that there were unique circumstances applicable to the mains that

32 Ibid, Attachment MFB-1, page 4.

were installed during those particular years that made it feasible to install them at relatively little cost. The $1,672.55 per Dth estimate appears to be more plausible for use on a going-forward basis.

V. RECOMMENDATIONS

Q. What are your recommendations concerning the Company's rate design?

A. Reasonable steps can and should be taken in this proceeding to strengthen the incentive for customers to increase the insulation in their home or business and to replace existing, inefficient water heaters and furnaces with more energy efficient ones.

Because of the problems I just explained, the Company's marginal cost estimates should not be relied upon as filed. Instead, the monthly customer charges should be increased, and the tail block rates should be increased more than the initial block rates. By decreasing the fixed part of the bill and increasing the per-therm rates, especially in the tail block, the Commission can reduce the burden on small customers, make the tariff structure more equitable, enable customers to gain greater control over their monthly utility bill, and advance the broad public interest by encouraging energy efficiency.

Q. Have you developed some rate calculations to illustrate your recommendations?

A. Yes. For ease of comparison, I used the same general methodology as the Company. To overcome the Company’s grossly excessive estimate of the level of marginal costs, I started with the assumption that customer-related marginal costs were 20% of the level estimated by the Company. This is based, in part, on my assumption that the Company's engineering cost estimates for services, regulators and meters would be applicable to no more than 10 to 15% of all locations in a long-run planning horizon. The costs in other locations are almost entirely fixed or sunk. This estimate also considers the marginal cost of reading the meter and mailing and printing a bill to each customer.

I also assumed the dummy variable for 2012-2016 main extensions is unique to those four years, and therefore the long run marginal cost of main extensions is $1,672.55 per Dth, rather than $505.18. By this assumption I am not implying that other parts of the study were accurately developed. Rather, my intent is simply to provide an order-of-magnitude indication of the potential impact of increasing the usage-related marginal cost estimates to a more realistic level.

Similarly, I used the Company's proposed revenue requirement to prepare these illustrative rates. To be clear, this does not imply any sort of endorsement of the proposed revenue requirement, or specific details of the rate development methodology that I have not discussed. To the contrary, I am anticipating that the revenue requirement determined by the Commission will be lower than the one assumed in these calculation; this will alleviate the larger bill impacts shown in my exhibit.

Q. Can you briefly explain how you developed these illustrative rates?

A. Schedule 1 of my exhibit highlights some key numbers from the revised marginal cost calculations which I used to develop these illustrative rates. Taking these marginal cost estimates into account, but moderating the adjustments to maintain a greater degree of rate continuity, I adjusted the customer charges as shown in the following table.

Customer Class	Current Rate	Marginal Cost	Proposed Rate	Illustrative Rate
R-1 Residential Non-Heat	$15.27	$11.37	$21.50	$11.50
R-3 Residential Heat	$22.10	$11.11	$25.50	$12.75
G-41 C & I Low Load Factor Low Annual	$48.36	$12.44	$55.61	$35.00
G-42 C & I Low Load Factor Medium Annual	$145.08	$23.44	$159.59	$100.00
G-43 C & I Low Load Factor High Annual	$622.61	$39.66	$684.87	$400.00
G-51 C & I High Load Factor Low Annual	$48.36	$12.52	$55.61	$35.00
G-52 C & I High Load Factor Medium Annual	$145.08	$21.67	$159.59	$100.00
G-53 C & I High Load Factor High Annual	$640.74	$68.43	$704.81	$400.00
G-54 C & I High Load Factor High Annual	$640.74	$140.80	$704.81	$400.00

As shown in Schedule 2 of my exhibit, I also eliminated or flattened the existing declining block rate structure. The illustrative rates are linked to the requested revenue requirement for comparison purposes. However, in recommending this flattening of the block rate structure, I am assuming the final revenue requirement will actually be lower, and therefore the rate increase borne by large customers will not be as severe as that shown in my exhibit. To the extent large bill impacts persist after adjusting the rates to match the final revenue requirement, it would be appropriate to phase-in the rate changes, rather than implementing everything in a single year.

Q. Have you looked at how these illustrative rates would impact the newly acquired Keene division?

A. Yes. Customers in the Keene division are currently paying rates that are closer to my illustrative rate design than to the Company's proposed rate design. This is particularly evident with respect to the fixed customer charges, as shown in the following table.

Customer Class	Current Rate	Marginal Cost	Proposed Rate	Illustrative Rate
R-1 Residential Non-Heat	$9.00	$11.37	$21.50	$11.50
R-3 Residential Heat	$9.00	$11.11	$25.50	$12.75
G-41 C & I Low Load Factor Low Annual	$18.00	$12.44	$55.61	$35.00
G-42 C & I Low Load Factor Medium Annual	$18.00	$23.44	$159.59	$100.00
G-51 C & I High Load Factor Low Annual	$18.00	$12.52	$55.61	$35.00
G-52 C & I High Load Factor Medium Annual	$18.00	$21.67	$159.59	$100.00

Q. What are your recommendations concerning the proposed decoupling mechanism?

A. I recommend replacing the existing LRAM with a total revenue decoupling mechanism. If it is feasible to do so, I also recommend using a "real-time" mechanism, which will provide customers with a direct, tangible benefit by smoothing out unexpected weather-related bill fluctuations. While this approach has the disadvantage of adding some administrative costs and complexities, it has the offsetting advantage of improving the timing of cash flows for both customers and stockholders, as discussed earlier in my testimony.

Q. Does this conclude your direct testimony, which was prefiled on November 30, 2017?

A. Yes.

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Less November 2018 – October 2019 LDAC Costs

Docket No. DG 18-137

Amended Technical Statement of David B. Simek and Catherine A. McNamara

October xx, 2018

A. Purpose of Technical Statement.

The purpose of this technical statement is to make the Commission aware that in the review of the 2018/2019 filing we noticed that the residential energy efficiency over collection for the last year was very similar to the previous year's residential energy efficiency budget. Upon researching this further it was discovered that the low income portion of the energy efficiency budget was included in the residential program budget and was also included as an allocation between both residential and commercial & industrial LDAC rates. Although we have followed the same process since the winter of 2014/2015, residential customers were only impacted during the winter of 2014/2015 due to the running balance of the over/under collection. Post winter 2014/2015 the additional low income costs included in the residential EE rate were substantially offset by the prior year over-collection. We want to make the commission aware that the Company plans to reduce the residential LDAC rate that is effective November 1, 2018 by $0.0163 per therm from the previously filed proposed rate of $0.0836 per therm. The adjusted residential LDAC rate is $0.0673per therm.

B. Reason for a Reduction in Local Distribution Adjustment Clause (LDAC) Costs of $1,310,342.

The Company had originally filed the residential LDAC rate at $0.0836 per therm and the commercial & industrial LDAC rate at $0.0772 per therm both effective November 1, 2018 – October 31, 2019. Since the original filing, the Company identified that the low income portion of the energy efficiency program budget was over stated by $1,310,342 (see Attachment 1 for additional details) within the residential calculation. The adjusted residential LDAC rate is $0.0673 per therm.

C. Customer Impact.

This impacts residential customers only. The projected total bill seasonal increase for a typical residential non-fixed price heating customer from the 2018/2019 winter season is projected to be $56.81 with the adjusted LDAC rate. The originally filed projected seasonal increase was $10.36 higher at $67.17. A bill comparison is included as Attachment 2.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Docket No. DG 18-137
Winter 2018/2019 Cost of Gas & Summer 2019 Cost of Gas
Technical Statement of David B. Simek and Catherine A McNamara
Attachment 1

2019 EE Budget Included in ENNG COG

Included in filing 9/4/18

	Residential Original Budget	C&I Original Budget	Total
2019 Program Budget	$4,381,186	$4,625,642	$9,006,828
2019 Portion of Low Income Program Budget	$468,703	$841,639	$1,310,342
	$4,849,889	$5,467,281	$10,317,170

What the 9/4/18 filing should have been

	Revised Residential	C&I Original Budget	Total
2019 Program Budget	$3,070,844	$4,625,642	$7,696,486
2019 Low Income Program Budget	$1,310,342	$0	$1,310,342
2019 Low Income Program Budget	($1,310,342)	$0	($1,310,342)
2019 Portion of Low Income Program Budget Allocation	$468,703	$841,639	$1,310,342
	$3,539,547	$5,467,281	$9,006,828

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

November 1, 2018 - April 30, 2019 | **May 1, 2018 - October 31, 2018**
Residential Heating (R3)

PROPOSED			**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Winter Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
	5/1/2018	7/1/2018															
Winter:																	
Cust. Chg	$24.43	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12								
Headblock	$0.3863	$0.5631	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
Tailblock	$0.3197	$0.5631	$21.33	$53.70	$88.19	$78.12	$60.12	$56.40	$357.86								
HB Threshold	100	-															
Summer:																	
Cust. Chg	$14.88	$15.02								$14.88	$14.88	$15.02	$15.02	$15.02	$15.02	$89.84	$179.96
Headblock	$0.5580	$0.5631								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.5580	$0.5631								$30.99	$11.84	$9.43	$8.47	$8.80	$10.15	$79.67	$437.53
HB Threshold	-	-															
Total Base Rate Amount			$36.35	$68.72	$103.21	$93.14	$75.14	$71.42	$447.98	$45.87	$26.72	$24.45	$23.49	$23.82	$25.17	$169.51	$617.49
COG Rate - (Seasonal)			$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.3133	$0.3916	$0.3127	$0.3665	$0.3916	$0.3916	$0.3491	$0.6694
COG amount			$28.07	$70.68	$116.07	$102.82	$79.12	$74.23	$470.98	$17.40	$8.31	$5.24	$5.51	$6.12	$7.06	$49.63	$520.62
LDAC			$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0723
LDAC amount			$2.55	$6.42	$10.55	$9.34	$7.19	$6.74	$42.79	$5.25	$2.00	$1.58	$1.42	$1.48	$1.70	$13.44	$56.23
Total Bill			**$66.96**	**$145.82**	**$229.82**	**$205.31**	**$161.45**	**$152.40**	**$961.76**	**$68.51**	**$37.03**	**$31.27**	**$30.42**	**$31.42**	**$33.93**	**$232.58**	**$1,194.34**

November 1, 2017 - April 30, 2018 | **May 1, 2017 - October 31, 2017**
Residential Heating (R3)

CURRENT			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
Winter:	5/1/2017	7/1/2017															
Cust. Chg	$22.10	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58								
Headblock	$0.3495	$0.3863	$14.63	$36.84	$38.63	$38.63	$38.63	$38.63	$205.99								
Tailblock	$0.2892	$0.3197	$0.00	$0.00	$18.10	$12.39	$2.16	$0.05	$32.70								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$22.10	$24.43								$22.10	$22.10	$24.43	$24.43	$24.43	$24.43	$141.92	$288.50
Headblock	$0.3495	$0.3863								$6.99	$6.99	$6.47	$5.81	$6.04	$6.96	$39.26	$245.25
Tailblock	$0.2892	$0.3197								$10.27	$0.35	$0.00	$0.00	$0.00	$0.00	$10.63	$43.32
HB Threshold	20	20															
Total Base Rate Amount			$39.06	$61.27	$81.16	$75.45	$65.22	$63.11	$385.27	$39.36	$29.44	$30.90	$30.24	$30.47	$31.39	$191.81	$577.08
COG Rate - (Seasonal)			$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7321	$0.4368	$0.4368	$0.4368	$0.4725	$0.4725	$0.4725	$0.4490	$0.6804
COG amount			$24.41	$61.46	$100.94	$111.77	$86.01	$80.69	$465.28	$24.26	$9.27	$7.31	$7.11	$7.39	$8.52	$63.84	$529.12
LDAC			$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0817
LDAC amount			$3.24	$8.16	$13.41	$11.88	$9.14	$8.57	$54.40	$3.55	$1.36	$1.07	$0.96	$1.00	$1.15	$9.10	$63.50
Total Bill			**$66.71**	**$130.90**	**$195.50**	**$199.09**	**$160.37**	**$152.38**	**$904.95**	**$67.17**	**$40.07**	**$39.28**	**$38.31**	**$38.85**	**$41.07**	**$264.75**	**$1,169.70**

DIFFERENCE:

Total Bill	**$0.25**	**$14.92**	**$34.32**	**$6.22**	**$1.08**	**$0.02**	**$56.81**	**$1.34**	**($3.04)**	**($8.02)**	**($7.89)**	**($7.43)**	**($7.13)**	**($32.17)**	**$24.64**
% Change	**0.38%**	**11.40%**	**17.55%**	**3.12%**	**0.67%**	**0.01%**	**6.28%**	**1.99%**	**-7.58%**	**-20.41%**	**-20.59%**	**-19.13%**	**-17.37%**	**-12.15%**	**2.11%**
Base Rate	($2.71)	$7.45	$22.05	$17.70	$9.92	$8.31	$62.71	$6.50	($2.72)	($6.45)	($6.75)	($6.65)	($6.22)	($22.29)	$40.42
% Change	-6.95%	12.16%	27.17%	23.46%	15.20%	13.17%	16.28%	16.51%	-9.25%	-20.87%	-22.33%	-21.81%	-19.82%	-11.62%	7.00%
COG & LDAC	$2.97	$7.47	$12.27	($11.48)	($8.84)	($8.29)	($5.90)	($5.16)	($0.31)	($1.57)	($1.14)	($0.79)	($0.91)	($9.88)	($15.78)
% Change	12.15%	12.15%	12.15%	-10.27%	-10.27%	-10.27%	-1.27%	-21.29%	-3.37%	-21.43%	-15.98%	-10.67%	-10.67%	-15.47%	-2.98%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2019 Summer Cost of Gas Filing
Annual Bill Comparisons, May 18 - Oct 18 vs May 19 - Oct 19 - Residential Heating Rate R-3

November 1, 2018 - April 30, 2019 / **May 1, 2019 - October 31, 2019**
Residential Heating (R3)

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr		May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		38	95	157	139	107	100	636		56	21	17	15	16	18	142	778
	7/1/2018																
Winter:																	
Cust. Chg	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12									
Headblock	$0.5631	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00									
Tailblock	$0.5631	$21.33	$53.70	$88.19	$78.12	$60.12	$56.40	$357.86									
HB Threshold	-																
Summer:									0.4445								
Cust. Chg	$15.02								0.3133	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12	$180.24
Headblock	$0.5631								0.1312	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Tailblock	$0.5631									$31.27	$11.95	$9.43	$8.47	$8.80	$10.15	$80.06	$437.92
HB Threshold	-								0.418768								
Total Base Rate Amount		$36.35	$68.72	$103.21	$93.14	$75.14	$71.42	$447.98		$46.29	$26.97	$24.45	$23.49	$23.82	$25.17	$170.18	$618.16
COG Rate - (Seasonal)		$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411		$0.4445	$0.4445	$0.4445	$0.4445	$0.4445	$0.4445	$0.4445	$0.6869
COG amount		$28.07	$70.68	$116.07	$102.82	$79.12	$74.23	$470.98		$24.68	$9.43	$7.44	$6.68	$6.95	$8.01	$63.20	$534.18
LDAC		$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	0.0673		$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0673	$0.0673
LDAC amount		$2.55	$6.42	$10.55	$9.34	$7.19	$6.74	$42.79		$3.74	$1.43	$1.13	$1.01	$1.05	$1.21	$9.57	$52.37
Total Bill		**$66.96**	**$145.82**	**$229.82**	**$205.31**	**$161.45**	**$152.40**	**$961.76**		**$74.71**	**$37.82**	**$33.02**	**$31.18**	**$31.82**	**$34.40**	**$242.96**	**$1,204.72**

November 1, 2017 - April 30, 2018 / **May 1, 2018 - October 31, 2018**
Residential Heating (R3)

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
Winter:															
Cust. Chg	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58								
Headblock	$14.63	$36.84	$38.63	$38.63	$38.63	$38.63	$205.99								
Tailblock	$0.00	$0.00	$18.10	$12.39	$2.16	$0.05	$32.70								
HB Threshold															
Summer:															
Cust. Chg								$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58	$293.16
Headblock								$7.73	$7.73	$6.26	$5.45	$5.43	$7.73	$40.33	$246.32
Tailblock								$8.99	$2.23	$0.00	$0.00	$0.00	$0.52	$11.74	$44.44
HB Threshold															
Total Base Rate Amount	$39.06	$61.27	$81.16	$75.45	$65.22	$63.11	$385.27	$41.15	$34.39	$30.69	$29.88	$29.86	$32.68	$198.65	$583.92
COG Rate - (Seasonal)	$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7321	$0.3133	$0.3916	$0.3127	$0.3665	$0.3916	$0.3916	$0.3491	$0.6621
COG amount	$24.41	$61.46	$100.94	$111.77	$86.01	$80.69	$465.28	$17.40	$8.31	$5.24	$5.51	$6.12	$7.06	$49.63	$514.91
LDAC	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0872
LDAC amount	$3.24	$8.16	$13.41	$11.88	$9.14	$8.57	$54.40	$5.25	$2.00	$1.58	$1.42	$1.48	$1.70	$13.44	$67.84
Total Bill	**$66.71**	**$130.90**	**$195.50**	**$199.09**	**$160.37**	**$152.38**	**$904.95**	**$63.79**	**$44.70**	**$37.51**	**$36.81**	**$37.46**	**$41.44**	**$261.72**	**$1,166.67**

DIFFERENCE:

Total Bill	**$0.25**	**$14.92**	**$34.32**	**$6.22**	**$1.08**	**$0.02**	**$56.81**	**$10.92**	**($6.88)**	**($4.49)**	**($5.63)**	**($5.64)**	**($7.04)**	**($18.76)**	**$38.05**
% Change	**0.38%**	**11.40%**	**17.55%**	**3.12%**	**0.67%**	**0.01%**	**6.28%**	**17.11%**	**-15.39%**	**-11.97%**	**-15.29%**	**-15.05%**	**-17.00%**	**-7.17%**	**3.26%**
Base Rate	($2.71)	$7.45	$22.05	$17.70	$9.92	$8.31	$62.71	$5.14	($7.42)	($6.24)	($6.39)	($6.04)	($7.51)	($28.47)	$34.25
% Change	-6.95%	12.16%	27.17%	23.46%	15.20%	13.17%	16.28%	12.49%	-21.59%	-20.33%	-21.39%	-20.22%	-22.98%	-14.33%	5.86%
COG & LDAC	$2.97	$7.47	$12.27	($11.48)	($8.84)	($8.29)	($5.90)	$5.78	$0.55	$1.75	$0.76	$0.40	$0.46	$9.71	$3.80
% Change	10.73%	10.73%	10.73%	-9.29%	-9.29%	-9.29%	-1.14%	25.51%	5.29%	25.70%	11.03%	5.29%	5.29%	15.39%	0.65%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00