

**STATE OF NEW HAMPSHIRE  
BEFORE THE  
PUBLIC UTILITIES COMMISSION**

Docket No. DG 17-\_\_\_

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities  
Approval of Natural Gas Supply Strategy

**PRE-FILED DIRECT TESTIMONY**

**OF**

**WILLIAM R. KILLEEN**

**AND**

**JAMES M. STEPHENS**

December 21, 2017

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1 **I. INTRODUCTION**

2 **Q. Please state your name, affiliation, and business address.**

3 A. My name is William R. (Bill) Killeen. I am Director, Energy Procurement of Liberty  
4 Utilities (Canada) Corp., the parent of Liberty Utilities Co. (“Liberty Utilities”), which is  
5 the parent company of Liberty Energy Utilities (New Hampshire) Corp. (“Liberty Energy  
6 (NH)”). My business address is 345 Davis Road, Oakville, Ontario, Canada.

7 My name is James M. Stephens. I am a Partner of ScottMadden, Inc. (“ScottMadden”).  
8 My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts  
9 01581.

10 **Q. On whose behalf are you submitting this testimony?**

11 A. We are submitting this joint testimony before the New Hampshire Public Utilities  
12 Commission (the “Commission” or “NHPUC”) on behalf of Liberty Utilities (EnergyNorth  
13 Natural Gas) Corp. d/b/a Liberty Utilities (hereinafter referred to as “EnergyNorth” or the  
14 “Company”), a subsidiary of Liberty Energy (NH).

15 **Q. Mr. Killeen, please summarize your educational background, and your business and  
16 professional experience.**

17 A. I earned a Bachelor of Engineering Science (Chemical) degree from the University of  
18 Western Ontario (now Western University) in 1985. I also earned a Master’s degree in  
19 Business Administration from the Ivey School of Business at Western University in 1989.

1 I have 28 years of professional experience in the energy and utilities industries in the areas  
2 of regulation, supply, operations, and customer service. I have worked at natural gas and  
3 electric utilities, as well as in consulting, marketing, and government positions. Early in  
4 my career, I was employed by Union Gas Limited, a major natural gas utility serving over  
5 1.4 million customers in Ontario, Canada, for twelve years in varying capacities, including  
6 regulatory and supply. Prior to joining Liberty Utilities in February 2014, I was employed  
7 by Enersource Hydro Mississauga Inc., a major electric utility serving the City of  
8 Mississauga, Ontario, for three years as Manager, Regulatory Affairs. In between my  
9 employment at these two large utilities, I was employed at various other companies, always  
10 retaining responsibility for oversight of regulatory affairs and supply, typically in Ontario  
11 or eastern Canada. These companies included Engage Energy Canada Inc., Direct Energy  
12 as Manager, Regulatory Affairs and a consulting company, ECNG Energy LP, as Director,  
13 Supply and Regulatory Affairs for eight years. Following ECNG, I spent a brief tenure  
14 within the Ministry of Energy of the Ontario Government. Please refer to Exhibit  
15 WRK/JMS-1 for a summary of my professional background.

16 **Q. Mr. Killeen, have you previously testified before any regulatory bodies?**

17 **A.** Yes, I have. In the United States, I have provided testimony in a number of proceedings in  
18 Arizona, California, Arkansas, Montana, Georgia, and Texas. In Canada, I have testified  
19 in approximately 18 natural gas and electric utility pricing cases and facility approval cases  
20 before the Ontario Energy Board. Please refer to Exhibit WRK/JMS-1 for a summary of  
21 my past testimony appearances.

1 **Q. Mr. Stephens, please summarize your education background and your professional**  
2 **experience in the energy and utility industries.**

3 A. I hold a Bachelor of Science degree in Management and a Master of Business  
4 Administration with a concentration in Operations Management from Bentley College. I  
5 have 30 years of experience in the energy industry and have held senior management  
6 positions at consulting firms, a retail energy marketing company, and natural gas local  
7 distribution companies (“LDCs”). In my role as a consultant, I have assisted numerous  
8 clients with various natural gas related engagements, including: the analysis of regional  
9 energy market dynamics and the associated drivers for new natural gas infrastructure; the  
10 evaluation of capacity opportunities associated with open seasons on various pipelines; the  
11 evaluation of new markets/opportunities; integrated resource plans; and natural gas supply  
12 portfolio evaluation and optimization. In addition, in my role as the President of a retail  
13 energy marketing firm, I was responsible for all aspects of business unit management  
14 including front, mid, and back-office functions. I was also responsible for Gas Supply  
15 Procurement and Portfolio Optimization for Colonial Gas Company, which is now a  
16 subsidiary of National Grid. A summary of my professional and educational background  
17 is provided as Exhibit WRK/JMS-2.

18 **Q. Mr. Stephens, have you previously provided testimony before the Commission?**

19 A. Yes, I have submitted expert testimony to the Commission on behalf of Public Service  
20 Company of New Hampshire d/b/a Eversource Energy regarding its natural gas capacity  
21 contract filing in Docket No. DE 16-241.

1 **Q. Mr. Stephens, have you submitted expert testimony in other regulatory jurisdictions?**

2 A. Yes, I have submitted expert testimony in several other regulatory jurisdictions, including  
3 the Federal Energy Regulatory Commission (“FERC”), the states of Massachusetts and  
4 Maine, and the Canadian provinces of Ontario, Québec, New Brunswick, and Alberta. A  
5 list of my past expert witness appearances is provided as Exhibit WRK/JMS-3.

6 **II. EXECUTIVE SUMMARY**

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

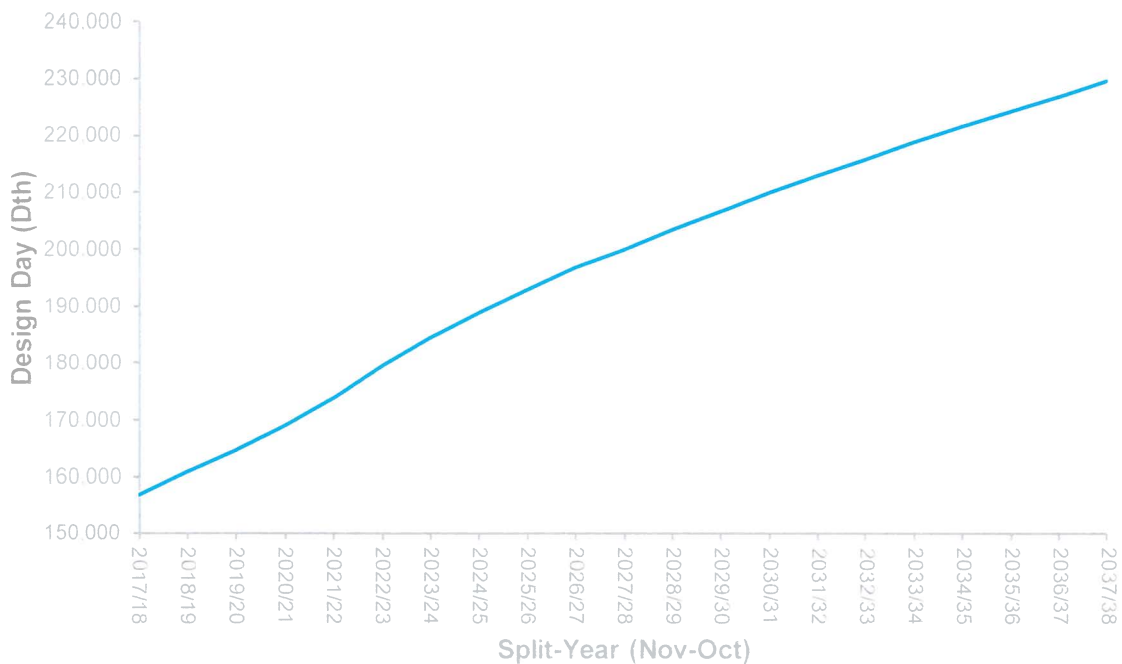
8 A. The purpose of our joint testimony is to present to the Commission, for its review, the  
9 various market factors that have influenced EnergyNorth’s natural gas supply strategy and  
10 associated infrastructure development and contract decisions to meet its projected long-  
11 term (i.e., 2017/18 through 2037/38) natural gas demand requirements. In addition, our  
12 testimony reviews the process and analyses undertaken by the Company to evaluate the  
13 available resource options and determine the best-cost portfolio for EnergyNorth and its  
14 customers. Finally, our testimony reviews the contract terms and details regarding each of  
15 the Company’s capacity contract decisions and proposed infrastructure development  
16 projects that comprise its natural gas supply strategy.



1 **Q. Please provide an overview of the Company’s projected growth in demand and the**  
2 **factors that have affected EnergyNorth’s natural gas supply strategy.**

3 A. As demonstrated in this filing, EnergyNorth has experienced an increase in demand for  
4 natural gas and is forecasting continued growth in both winter period<sup>1</sup> and Design Day  
5 demand. As shown in Figure 1 below, the Company’s Design Day demand for natural gas  
6 is projected to increase by a compound annual growth rate (“CAGR”) of approximately  
7 1.9% from 156,822 dekatherms (“Dth”)<sup>2</sup> in 2017/18 to 229,590 Dth in 2037/38.

8 **Figure 1: EnergyNorth Design Day Demand Forecast**



9

<sup>1</sup> For purposes of this testimony, the winter period is defined as the five-month gas supply planning period from November to March, the summer period is the seven months from April to October, and a split-year is the 12-month period from November to October.

<sup>2</sup> For purposes of this testimony, we have assumed that 1 Dth = 1 thousand cubic feet (“Mcf”) = 1 million British thermal units (“MMBtu”).

1 This expected increase in natural gas demand is coupled with certain natural gas supply  
2 realities, including: the reduction in natural gas production from off-shore Nova Scotia; the  
3 continued growth in U.S. natural gas production; the complexity and time required to  
4 construct incremental pipeline capacity into New England; and the existing structure of the  
5 EnergyNorth natural gas supply portfolio, including the inevitable retirement of the  
6 Company's aging propane facilities. These and other factors detailed in the remainder of  
7 our testimony have resulted in incremental natural gas capacity and supply requirements  
8 for EnergyNorth.

9 **Q. Please provide a summary of the Company's resource evaluation approach.**

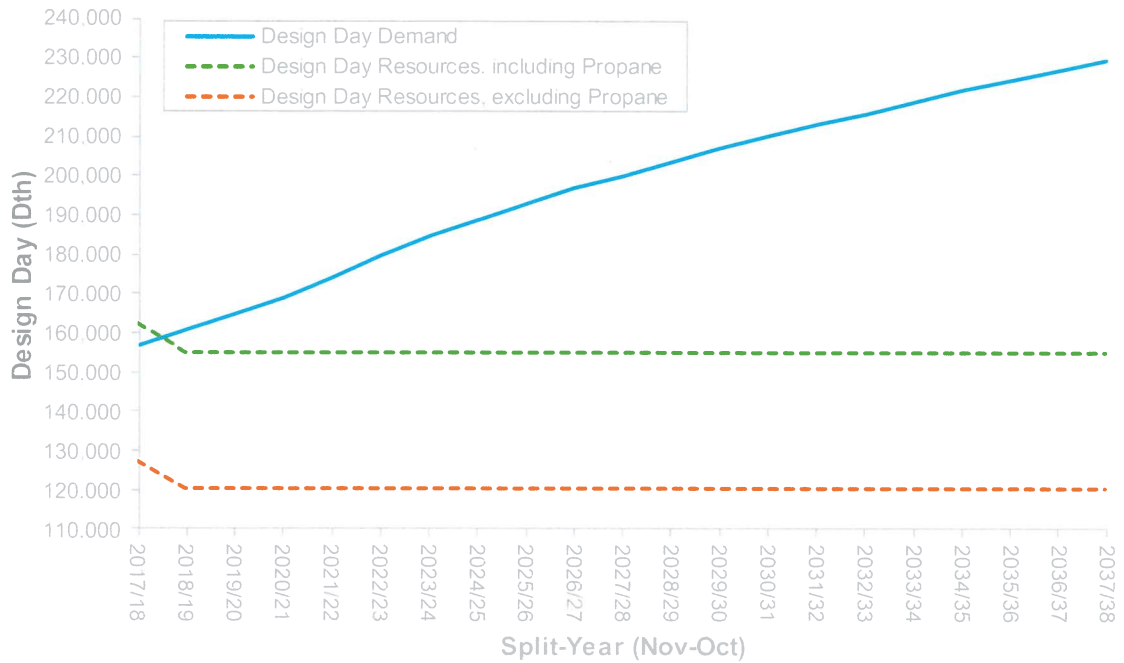
10 A. EnergyNorth has undertaken a comprehensive evaluation of available resource options that  
11 would allow the Company to serve its existing and future customer load requirements in a  
12 reliable and cost-effective manner. The EnergyNorth resource planning process, which is  
13 detailed in the Company's 2017 Integrated Resource Plan ("IRP")<sup>3</sup> and is consistent with  
14 the process used in the 2013 IRP and accepted by the Commission in Order No. 25,762  
15 (Feb. 9, 2015), is a multi-step process that includes an assessment of EnergyNorth's  
16 demand requirements (i.e., demand forecast) and a determination of resource need based  
17 on a review of incremental demand requirements compared to existing supply resources.  
18 Figure 2 below illustrates the projected Design Day demand requirements relative to  
19 EnergyNorth's existing Design Day resources, and the Company's growing resource  
20 deficit on Design Day.

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<sup>3</sup> The Company's 2017 IRP was filed with the Commission on October 2, 2017, in Docket No. DG 17-152.

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**Figure 2: EnergyNorth Design Day Demand and Resources<sup>4</sup>**



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As illustrated in Figure 2 above, EnergyNorth has incremental resource requirements on Design Day of 5,956 Dth beginning in the 2018/19 split-year, growing to 74,557 Dth by the end of the analysis period, and this need is more pronounced assuming the retirement of the Company’s aging propane facilities. Specifically, the EnergyNorth resource requirement on Design Day would increase by 34,600 Dth (from 74,557 Dth to 109,157 Dth by 2037/38), which is the current daily deliverability of the propane facilities. Once the determination that incremental resources were required to meet projected demand, the

<sup>4</sup> The 2017/18 Design Day resources include a contract with ENGIE Gas & LNG LLC (“ENGIE”) for a combination liquid/vapor service for up to 7,000 Dth per day, which terminates on March 31, 2018. See, Docket No. DG 17-135.

1 Company identified certain resource options and analyzed both quantitative and qualitative  
2 factors to determine the best-cost resource portfolio for EnergyNorth and its customers.

3 **Q. Please summarize the results of the analyses conducted by EnergyNorth to determine**  
4 **the best-cost portfolio for its customers over the long-term.**

5 A. Based on the Company's quantitative and qualitative analyses, EnergyNorth has  
6 determined that an investment in the Granite Bridge Project, which includes a new in-state  
7 pipeline (the Granite Bridge Pipeline) and a new on-system liquefied natural gas ("LNG")  
8 facility (the Granite Bridge LNG facility), coupled with firm pipeline transportation  
9 capacity from the Dawn Hub on the Union Gas Limited ("Union Gas") system, the  
10 TransCanada PipeLines Limited ("TCPL") Canadian Mainline, and Portland Natural Gas  
11 Transmission System ("PNGTS")<sup>5</sup> and the Company's existing supply portfolio, results in  
12 the most cost-effective resource portfolio for the customers of EnergyNorth over the long-  
13 term. In addition, the Company's long-term supply strategy, which leverages the flexibility  
14 of the individual assets and contracts, as well as the overall portfolio capability, increases  
15 reliability for its customers.

16 The Granite Bridge Pipeline will increase the security of gas supply deliveries and enable  
17 a more reliable, flexible, and diversified upstream gas supply portfolio by providing a

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<sup>5</sup> Gas supplies from the Dawn Hub are transported on Union Gas to the interconnection with the TCPL Canadian Mainline at Parkway, Ontario. As discussed further in Section VII.B, the Union Gas capacity is a component of the TCPL Canadian Mainline via a transportation-by-others ("TBO") and, therefore, for purposes of our testimony, references to the TCPL/PNGTS path from the Dawn Hub include the Union Gas component. The TCPL Canadian Mainline connects to the Trans-Québec and Maritimes Pipeline ("TQM"), which is jointly owned by TCPL and Gaz Métro, and the TQM system connects to PNGTS at the Québec/New Hampshire border at East Hereford.

1 second delivery feed to the Company’s service territory. The Granite Bridge LNG facility  
2 will provide EnergyNorth with a cost-effective, flexible, and reliable on-system asset to  
3 meet the growing Design Day and peak winter demand requirements. Finally, the  
4 TCPL/PNGTS capacity will provide the Company with additional resource flexibility and  
5 supply diversification, complementing the Granite Bridge LNG facility and allowing the  
6 Company to meet its growing demand requirements.

7 **Q. Given the lead time required to develop the Granite Bridge Project, is there a need**  
8 **for certain interim gas supply resources?**

9 A. Yes. Given the lead time required to develop and construct the Granite Bridge Project,  
10 EnergyNorth developed an interim gas supply strategy to meet the Company’s incremental  
11 demand requirements in the near-term (i.e., 2018/19 through 2021/22). Specifically,  
12 EnergyNorth has contracted with ENGIE for incremental natural gas supply delivered to  
13 the EnergyNorth city-gates or to its existing LNG facilities, which will assist the Company  
14 with meeting near-term demand requirements and liquid refill needs. The ENGIE contract,  
15 which is the only available resource option in the near-term that can be delivered, on a firm  
16 basis, to the EnergyNorth city-gates, will provide the Company with a cost-effective  
17 solution to meet its near-term incremental demand requirements while the Granite Bridge  
18 LNG facility and Granite Bridge Pipeline are being developed.

19 While the contract with ENGIE provides EnergyNorth with significant flexibility, it does  
20 not provide enough peaking deliverability to meet the Company’s projected near-term  
21 demand requirements. As a temporary solution, EnergyNorth will need to increase the

1 utilization of the Company’s existing LNG facilities by cycling the LNG storage capacity  
2 to meet the resource deficit until the proposed Granite Bridge Pipeline is available to  
3 deliver incremental supplies to the city-gates. At this time, EnergyNorth has not contracted  
4 for additional liquid-only supply or dedicated trucking service. The Company typically  
5 conducts a comprehensive request for proposals (“RFP”) process for liquid refill and  
6 trucking requirements for the upcoming winter period on a year-to-year basis, which would  
7 be reviewed by the Commission in the Company’s annual cost of gas filings.

8 **Q. Please summarize the EnergyNorth natural gas supply strategy for which the**  
9 **Company seeks Commission approval.**

10 A. As outlined in the joint testimony of Susan L. Fleck and Francisco C. DaFonte (the  
11 “Fleck/DaFonte Testimony”), EnergyNorth is seeking approval from the Commission for  
12 the following supply and capacity contract decisions together with two proposed  
13 infrastructure development projects to support the Company’s natural gas supply strategy:

- 14 • A contract with ENGIE for 90-day winter, combination (i.e., liquid and/or vapor)  
15 service with a maximum daily quantity (“MDQ”) of 7,000 Dth per day for the  
16 winters of 2018/19 through 2021/22;
- 17 • A precedent agreement with PNGTS, which outlines the Company’s binding  
18 request for 5,000 Dth per day of firm transportation capacity<sup>6</sup> from the Dawn Hub,

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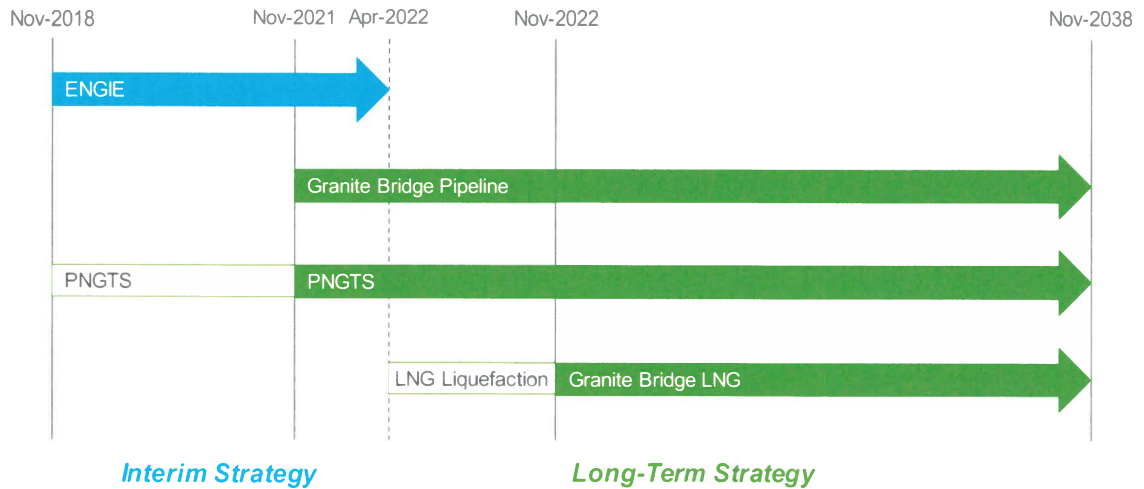
<sup>6</sup> As detailed in Section VII.B, the structure of the PNGTS precedent agreement has a TBO component that allows EnergyNorth to contract with PNGTS for the entire path from the Dawn Hub to Dracut, Massachusetts (i.e., capacity on Union Gas, TCPL Canadian Mainline, and PNGTS).

1 with phased-in service over three years starting November 1, 2018, and with an  
2 initial term of 22 years;

- 3 • Construction of the in-state Granite Bridge Pipeline, with an operating capacity of  
4 approximately 150,000 Mcf per day and an expected in-service date of November  
5 1, 2021; and
- 6 • Construction of the Granite Bridge LNG facility, which would connect to the  
7 proposed Granite Bridge Pipeline and have a total storage capacity of 2 Bcf,  
8 vaporization capacity of 150,000 Mcf per day, and liquefaction of 8,000 Mcf per  
9 day, to be in-service by April 1, 2022.

10 Together these supply and capacity contracts and proposed infrastructure projects comprise  
11 the Company's interim and long-term natural gas supply strategy as summarized in Figure  
12 3 below.

1 **Figure 3: EnergyNorth Natural Gas Supply Strategy<sup>7</sup>**



2 **Q. Is the Company’s strategy regarding an interim and long-term gas supply portfolio**  
3 **reasonable?**

4 **A.** Yes, it is. The ENGIE contract will help meet the Company’s near-term resource needs,  
5 provide flexibility and supply diversification, and allow the Company to transition to the  
6 long-term resource portfolio. The TCPL/PNGTS transportation capacity<sup>8</sup> will provide  
7 supply diversification in the near-term, and will provide additional reliability and flexibility  
8 benefits (i.e., increased access to the Dawn Hub, one of the more liquid natural gas pricing  
9 points with significant access to storage) once the proposed Granite Bridge Pipeline is in-  
10 service. In the long-term, the Granite Bridge Pipeline and Granite Bridge LNG facility  
11

<sup>7</sup> Note, as discussed later in this testimony, the PNGTS capacity will be phased-in over three years beginning on November 1, 2018, but given the current deliverability on Tennessee’s Concord Lateral, the PNGTS contract will not provide incremental supply to the Company’s city-gates until the proposed Granite Bridge Pipeline is on-line.

<sup>8</sup> As detailed in Section VII.B, the structure of the PNGTS precedent agreement has a TBO component that allows EnergyNorth to contract with PNGTS for the entire path from the Dawn Hub to Dracut, Massachusetts (i.e., capacity on Union Gas, TCPL Canadian Mainline, and PNGTS).



1 will significantly increase the reliability of the Company's gas supply portfolio by adding  
2 a second feed for deliveries, increase the Company's on-system assets, and better align the  
3 Company's demand profile and supply portfolio; enhance the flexibility of the gas supply  
4 portfolio by providing access to supplies from more sources, and the on-system LNG  
5 facility provides for load following service; and diversify the supply assets since the on-  
6 system LNG facility is a peaking resource for a growing peak demand. Finally, the interim  
7 and long-term supply portfolio provides cost-effective resources for EnergyNorth to meet  
8 its demand requirements, while allowing the option for retirement of the Company's aging  
9 propane facilities.

10 **Q. How is the remainder of your testimony organized?**

11 A. The remainder of our testimony is organized as follows:

- 12 • Section III – Regional Demand/Supply Dynamics: This section provides  
13 appropriate context regarding the regional natural gas market issues that the  
14 Company is currently facing. Specifically, the historical and projected natural gas  
15 demand drivers and regional natural gas supply trends have implications for the  
16 Company in terms of natural gas supply strategy and planning.
- 17 • Section IV – Review of EnergyNorth's Natural Gas Demand: In this section, we  
18 review the Company's significant growth in natural gas demand over the past five  
19 years, and summarize EnergyNorth's projected natural gas demand over the long-  
20 term forecast horizon. The approach, methodology, and results of the demand

1 forecast are consistent with the natural gas demand forecast filed with the  
2 Commission as part of the Company's 2017 IRP.

- 3 • Section V – Review of EnergyNorth's Current Natural Gas Portfolio: This section  
4 reviews and details the Company's existing natural gas resource portfolio.
- 5 • Section VI – EnergyNorth's Resource Evaluation Approach and Results: In this  
6 section, we summarize the primary objectives for the EnergyNorth resource  
7 portfolio and the criteria used to assess the resource options, review the process  
8 used to evaluate the Company's supply resource options, and discuss the  
9 quantitative and qualitative analyses undertaken by the Company to determine the  
10 best-cost portfolio for EnergyNorth and its customers.
- 11 • Section VII – Summary of EnergyNorth's Supply Strategy: In this section, we  
12 present details regarding each of the resource options that comprise the Company's  
13 interim and long-term strategies, including a review of tolls/rates, operational  
14 parameters, key contract terms, and timing of resource availability.
- 15 • Section VIII – Conclusion: This section summarizes our overall observations and  
16 conclusions regarding the EnergyNorth natural gas supply strategy.

17 **III. REGIONAL DEMAND/SUPPLY DYNAMICS**

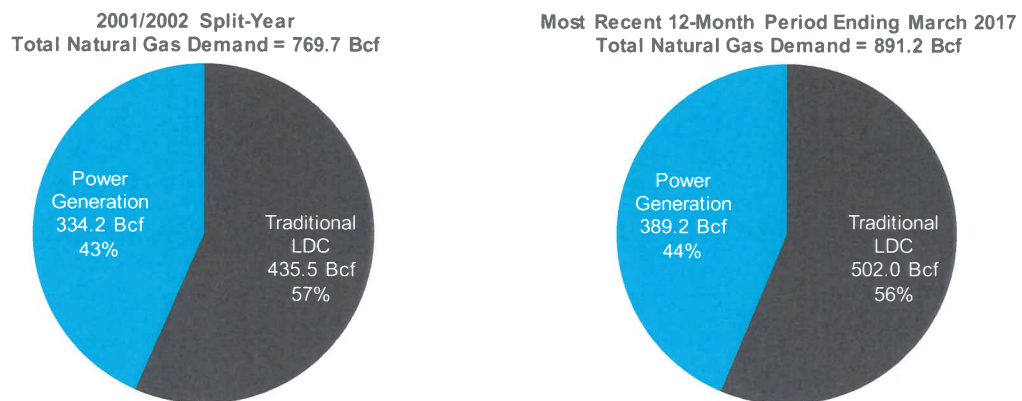
18 **A. Natural Gas Demand Drivers**

19 **Q. Has the demand for natural gas increased in New England?**

20 **A.** Yes, it has. The demand for natural gas in New England has significantly increased over  
21 the past 15 years. As illustrated in Figure 4, total annual natural gas demand in the region

1 has increased by 16% from approximately 770 Bcf in the 2001/02 split-year to  
2 approximately 891 Bcf in the 12-month period ending March 2017.<sup>9</sup>

3 **Figure 4: New England Annual Natural Gas Consumption by Sector<sup>10</sup>**



4  
5 The power generation and LDC sectors have exhibited similar growth trends over the past  
6 15 years. As shown in Figure 4, total annual natural gas consumption by the power  
7 generation sector has increased from approximately 334 Bcf to 389 Bcf (an increase of  
8 16%), while consumption by the traditional LDC segments (i.e., residential, commercial,  
9 and industrial) has increased from approximately 435 Bcf to 502 Bcf (an increase of  
10 15%).<sup>11</sup>

<sup>9</sup> Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine, release date May 31, 2017. Data for April through June 2016, September 2016, and January through March 2017 are based on ScottMadden estimates.

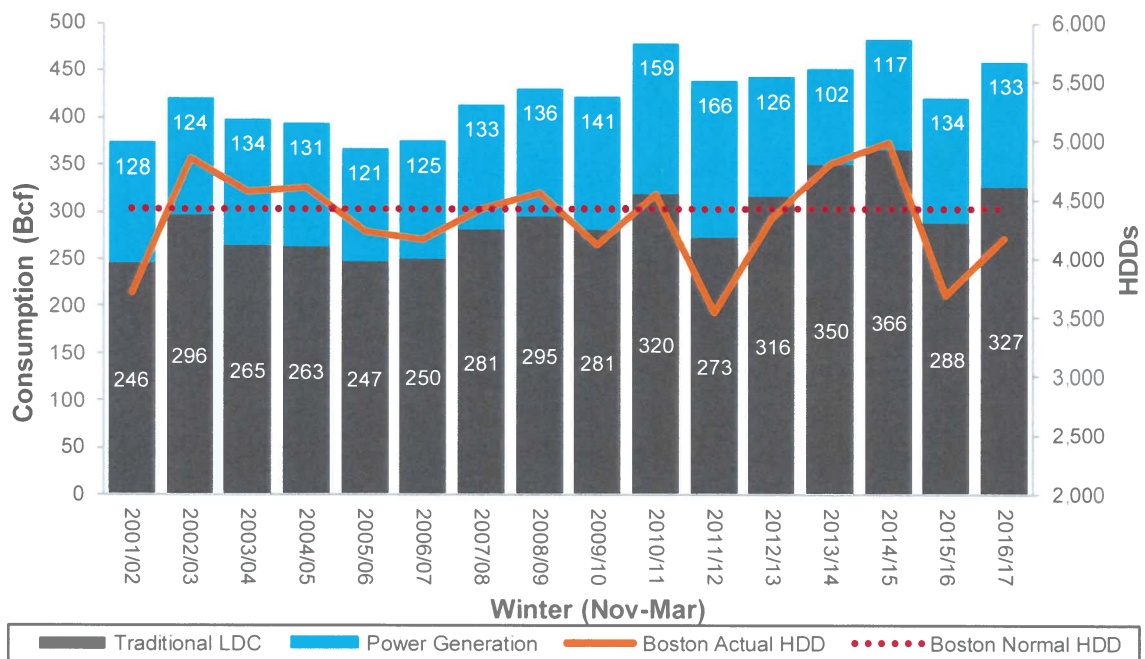
<sup>10</sup> Ibid.

<sup>11</sup> Ibid.

1 **Q. Please discuss the New England demand for natural gas in the winter, which is the**  
2 **peak season consumption for the traditional LDC segments.**

3 A. Overall, as illustrated in Figure 5 below, total winter natural gas demand in New England  
4 has increased by 23% from a total of approximately 374 Bcf in winter 2001/02 to 459 Bcf  
5 in winter 2016/17), which is higher than the increase in total annual demand in New  
6 England of 16%.<sup>12</sup>

7 **Figure 5: New England Winter Natural Gas Consumption<sup>13</sup>**



8

<sup>12</sup> Ibid.

<sup>13</sup> Sources: National Oceanic and Atmospheric Administration, National Climatic Data Center, Daily Summaries for Boston, Massachusetts; and U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine, release date May 31, 2017. Data for April through June 2016, September 2016, and January through March 2017 are based on ScottMadden estimates.

1 As shown by Figure 5 above, the demand for natural gas in New England fluctuates based  
2 on weather. Given the heat sensitive nature of LDC load, and since LDCs generally  
3 contract for firm pipeline capacity to serve their firm load requirements, there is higher  
4 natural gas consumption by the LDC sector in colder-than-normal winters. Whereas in  
5 warmer-than-normal winters, there is lower demand for natural gas by the LDC sector and  
6 thus available pipeline capacity to serve the natural gas demand requirements of the power  
7 generation segment. Stated differently, the two segments (i.e., the traditional LDC and  
8 power generation segments) may compete for pipeline capacity, particularly during the  
9 winter season. This competition for winter gas supplies, all else being equal, will place  
10 upward pressure on the New England natural gas price indices, resulting in higher and more  
11 volatile gas supply costs for entities that purchase gas supplies at these price indices.

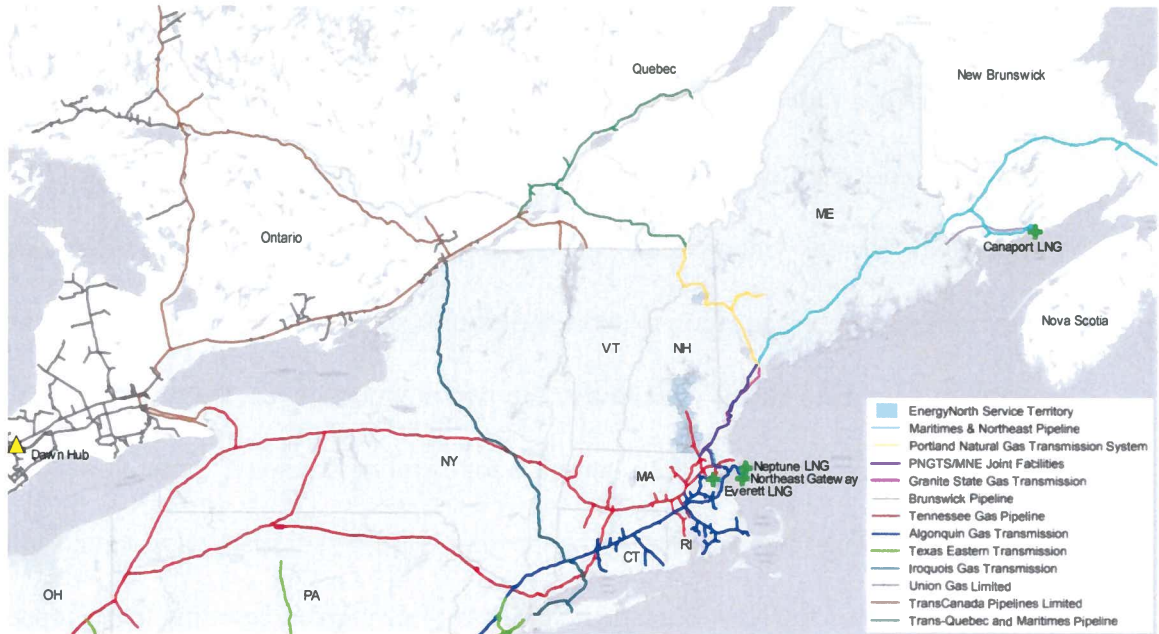
12 **B. Natural Gas Supply Trends**

13 **Q. What are the primary sources of natural gas supply for New England?**

14 A. As illustrated in Figure 6 below, the New England region is served by six natural gas  
15 pipelines: Tennessee Gas Pipeline Company, LLC (“Tennessee” or “TGP”), Algonquin  
16 Gas Transmission LLC (“Algonquin” or “AGT”), Iroquois Gas Transmission System, L.P.  
17 (“Iroquois” or “IGT”), Granite State Gas Transmission, Inc. (“GSGT”), PNGTS, and  
18 Maritimes & Northeast Pipeline (“MNE”). These pipelines provide access to various  
19 natural gas supply sources, including Canadian natural gas supplies (e.g., gas supply hub  
20 at Dawn, Ontario (“Dawn Hub”) and off-shore Nova Scotia supplies), U.S. domestic  
21 production (e.g., from the Gulf Coast and Appalachian basin), and imported LNG (e.g., the  
22 ENGIE Everett LNG and Canaport LNG facilities).

1

**Figure 6: New England Natural Gas Infrastructure<sup>14</sup>**



2

3 **Q. Please summarize the natural gas supply issues facing the New England market in**  
4 **general, and EnergyNorth in particular.**

5 **A.** The New England region is currently faced with the following natural gas supply trends:

- 6 • Dwindling natural gas supplies from off-shore Nova Scotia, which are a major  
7 supply source for MNE to serve natural gas demand in the Canadian Maritimes  
8 (i.e., Nova Scotia and New Brunswick) and New England markets.
- 9 • A significant increase in domestic U.S. natural gas production and reserves  
10 estimates, which supports the development of new natural gas infrastructure to  
11 deliver natural gas to various locations, including the Dawn Hub.

<sup>14</sup> Source: S&P Global Market Intelligence [modified by ScottMadden].

- 1           • Complexity and time required to construct incremental pipeline capacity.
- 2           • Seasonal focus of imported LNG volumes to serve the New England region.

3           Consequently, each of these supply trends impact the availability and feasibility of natural  
4           gas resource options for EnergyNorth and its customers as discussed in more detail below.

### 5           **1. Off-Shore Nova Scotia Supplies**

6           **Q. Please describe the natural gas supplies from off-shore Nova Scotia.**

7           A. The New England market has access to natural gas resources from off-shore Nova Scotia  
8           via the MNE system, which extends from Goldboro, Nova Scotia, through New Brunswick  
9           to a point at the Canada-U.S. border near Baileyville, Maine (i.e., MNE-Canada), and  
10          continues through Maine and New Hampshire into Massachusetts (i.e., MNE-US).<sup>15</sup>  
11          Specifically, the natural gas supplies from off-shore Nova Scotia are comprised of the  
12          Sable Offshore Energy Project (“SOEP”) and Deep Panuke Offshore Gas Development  
13          Project (“Deep Panuke”).

14          **Q. Please describe the current status of natural gas production from SOEP.**

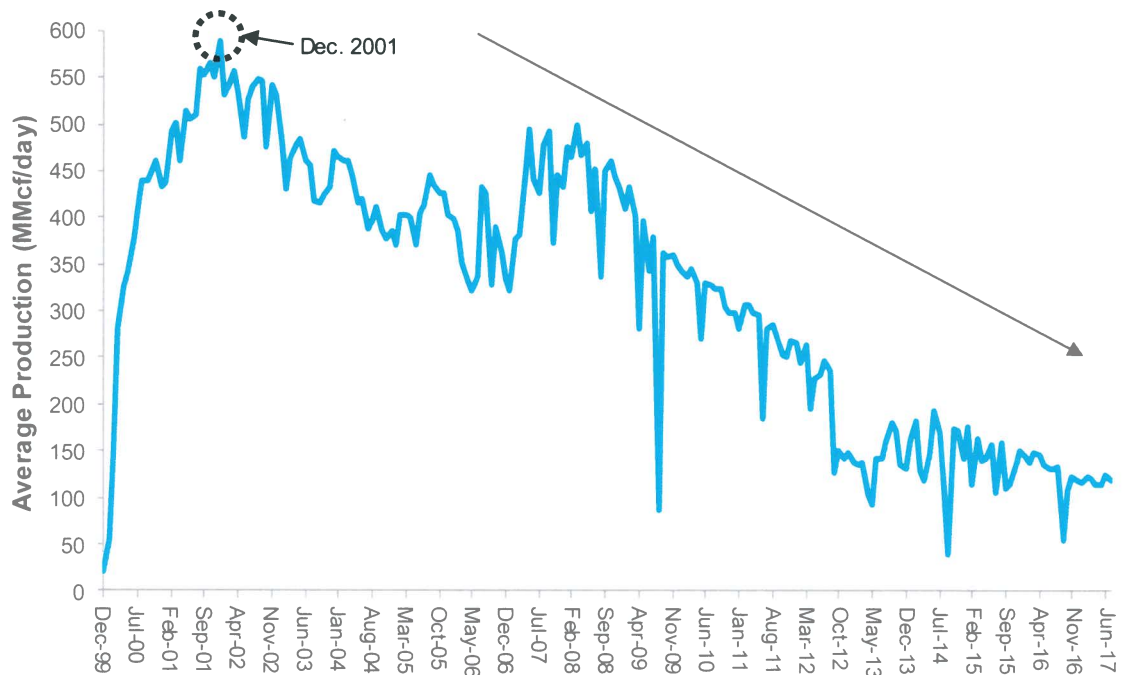
15          A. SOEP, which has been producing natural gas since late 1999, has been in a steady decline  
16          since 2009. As shown in Figure 7 below, average daily production from SOEP was  
17          approximately 120 million cubic feet (“MMcf”) per day this past winter of 2016/17, which

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<sup>15</sup> A portion of the MNE-US system from Westbrook, Maine, to Dracut is owned jointly by PNGTS and MNE and referred to as the “Joint Facilities.”

1 is an 80% decrease from its peak production in December 2001 of nearly 600 MMcf per  
2 day.<sup>16</sup>

3 **Figure 7: Average Daily SOEP Production<sup>17</sup>**



4  
5 **Q. Please describe the natural gas production trends from Deep Panuke.**

6 **A.** Natural gas production from Deep Panuke, which began in the summer of 2013, was  
7 expected to augment the natural gas supplies from SOEP, but Deep Panuke production has  
8 fallen short of expectations. Since inception, natural gas production from Deep Panuke

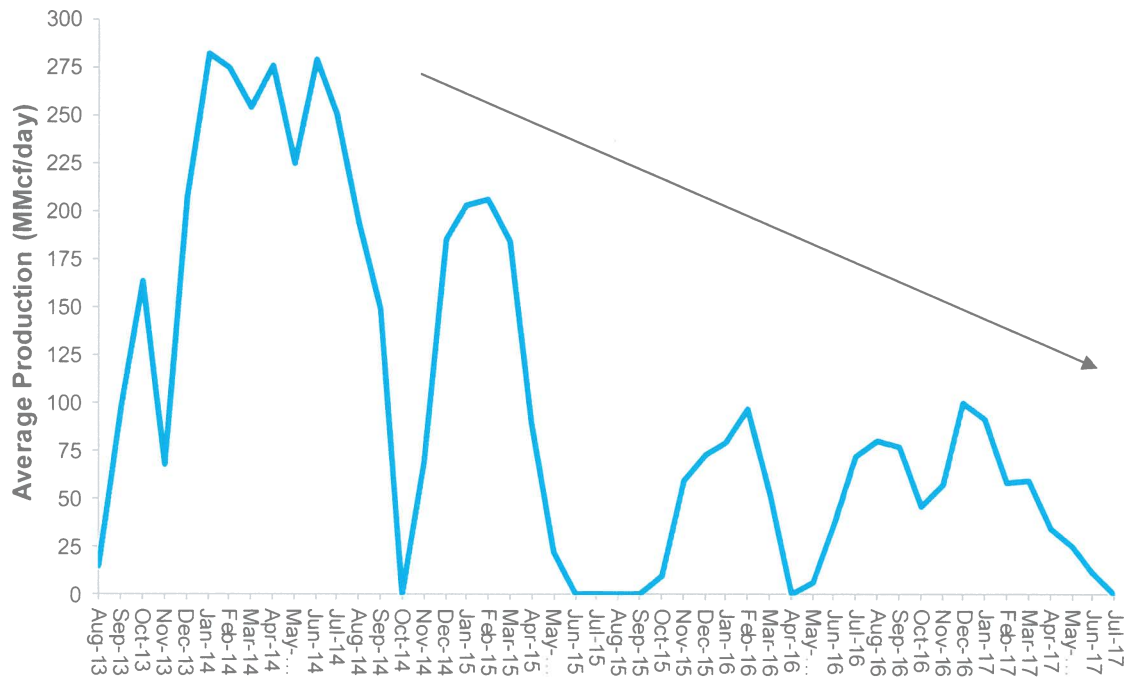
<sup>16</sup> Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, access date September 6, 2017.

<sup>17</sup> Ibid.



1 has been variable with daily production averaging less than 100 MMcf per day since April  
2 2015,<sup>18</sup> which is only one-third of the expected production level of 300 MMcf per day.<sup>19</sup>

3 **Figure 8: Average Daily Deep Panuke Production<sup>20</sup>**



4  
5 **Q. In summary, what is the current annual and winter natural gas production from**  
6 **SOEP and Deep Panuke and how does that compare to recent history?**

7 **A.** As shown in Table 1 below, the combined average daily production from SOEP and Deep  
8 Panuke was approximately 193 MMcf per day this past winter (i.e., winter 2016/17), which

<sup>18</sup> Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date September 6, 2017.

<sup>19</sup> Source: Nova Scotian Department of Energy; The Future of Natural Gas Supply for Nova Scotia. Prepared by ICF Consulting Canada, Inc., March 2013, at 35.

<sup>20</sup> Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date September 6, 2017.

1 is less than one-half of the average daily production of 365 MMcf per day in winter  
2 2013/14, the first winter period after Deep Panuke was placed in-service.

3 **Table 1: Average Daily SOEP and Deep Panuke Production<sup>21</sup>**

| Split-Year<br>(Nov-Oct) | Average Annual (MMcf/day) |             |       | Average Winter (MMcf/day) |             |       |
|-------------------------|---------------------------|-------------|-------|---------------------------|-------------|-------|
|                         | SOEP                      | Deep Panuke | Total | SOEP                      | Deep Panuke | Total |
| 2013/14                 | 141                       | 205         | 346   | 148                       | 217         | 365   |
| 2014/15                 | 141                       | 80          | 222   | 153                       | 170         | 323   |
| 2015/16                 | 130                       | 56          | 186   | 143                       | 72          | 214   |
| 2016/17                 | 119                       | 66          | 185   | 120                       | 73          | 193   |

4 Note: 2016/17 includes data through July 2017.

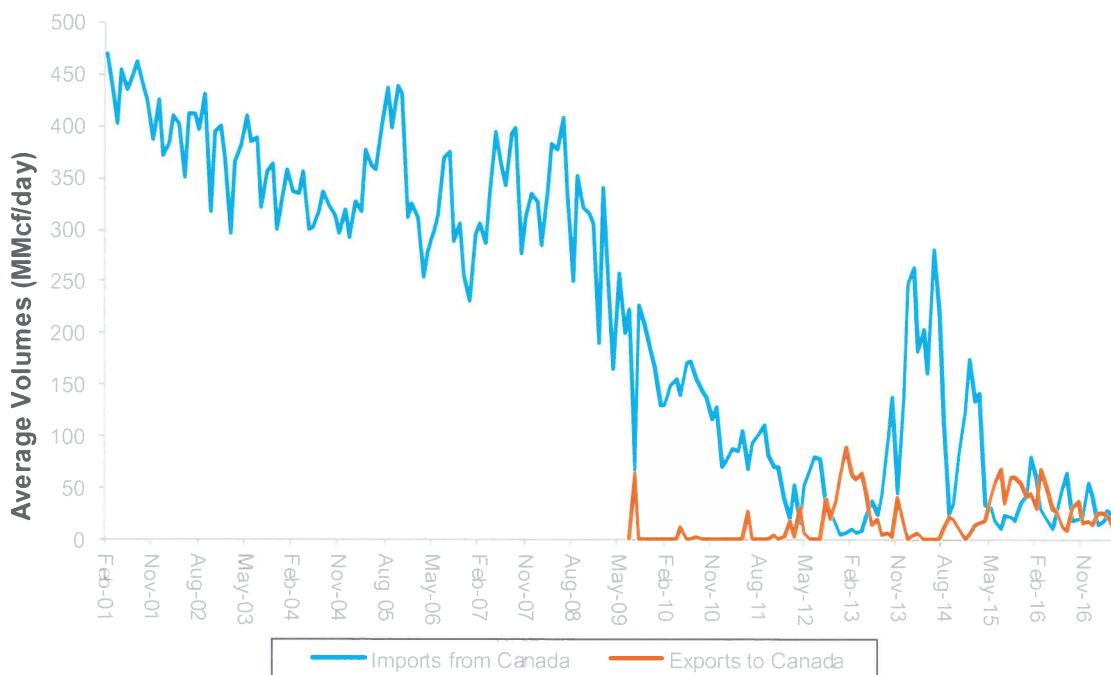
5 **Q. Has the decline in off-shore Nova Scotia natural gas supplies affected the level of**  
6 **imports from MNE into the U.S. to serve New England demand?**

7 **A.** Yes, it has. Since natural gas supplies from off-shore Nova Scotia are also used to serve  
8 demand in the Canadian Maritimes (i.e., Nova Scotia and New Brunswick), the decline in  
9 production from SOEP and Deep Panuke has resulted in little, if any, natural gas supplies  
10 available for the New England market. As shown in Figure 9 below, the average daily  
11 imports at Baileyville, Maine (i.e., the interconnection between MNE-Canada and MNE-  
12 US) has declined to an average of less than 30 MMcf per day in winter 2016/17.  
13 Conversely, during certain months the flow of natural gas has reversed and the Canadian  
14 Maritimes has imported natural gas from the U.S. Stated differently, as illustrated in Figure  
15 9, during certain months the volumes of natural gas exported from the U.S. to Canada at

<sup>21</sup> Sources: Canada-Nova Scotia Offshore Petroleum Board, Sable and Deep Panuke Monthly Production Reports, access date September 6, 2017.

1 the Baileyville, Maine point has exceeded the volumes imported to serve the New England  
2 region.

3 **Figure 9: Average Daily Imports and Exports at Baileyville, Maine<sup>22</sup>**



4

5 **Q. What is the expected long-term availability of natural gas supplies from off-shore**  
6 **Nova Scotia?**

7 **A.** Both SOEP and Deep Panuke are expected to be decommissioned over the next few years.  
8 Production from SOEP from December 1999 to July 2017 has totaled approximately 2.1

<sup>22</sup> Sources: National Energy Board of Canada, Natural Gas Exports - Monthly Summary by Port - Volume, access date September 6, 2017; and National Energy Board of Canada, Natural Gas Imports - Monthly Summary by Port - Volume, access date September 6, 2017. Data for imports and exports at the St. Stephen, New Brunswick point.

1 Tcf,<sup>23</sup> which is 90% of the total estimated reserves from SOEP of approximately 2.3 Tcf.<sup>24</sup>  
2 It is estimated that less than 10% of the total reserves from SOEP is remaining to be  
3 recovered. ExxonMobil Canada (“ExxonMobil”), operator and majority owner of SOEP,  
4 has recently initiated the decommissioning process for SOEP, with targeted completion by  
5 2020.<sup>25</sup>

6 In 2015, the initial total reserves estimate for Deep Panuke of 400 Bcf was reduced to 200  
7 Bcf.<sup>26</sup> As of July 2017, production from Deep Panuke has totaled approximately 146 Bcf,<sup>27</sup>  
8 which is over 70% of the reserves estimate (i.e., less than 30% of the total reserves  
9 remaining to be recovered). As such, Encana Corporation (“Encana”), the owner of Deep  
10 Panuke, has announced plans to commence the decommissioning process for Deep Panuke  
11 as early as 2019.<sup>28</sup>

12 **Q. What are the implications for New England given the recent developments associated**  
13 **with SOEP and Deep Panuke production?**

14 **A.** The decommissioning activity at SOEP and the announcements by Encana with respect to  
15 Deep Panuke paint a very stark supply picture for SOEP and Deep Panuke – there will  
16 likely be limited to no natural gas supplies from off-shore Nova Scotia by 2020. Therefore,

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<sup>23</sup> Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, access date September 6, 2017.

<sup>24</sup> The initial total reserves estimate of 3.0 Tcf was reduced to less than 2.3 Tcf in 2004. *See*, Natural Gas Intelligence, “Sable Producers Cut Reserves Estimates, But Analyst Optimistic on Continued Development,” February 4, 2004.

<sup>25</sup> *See*, Platts, “ExxonMobil Canada begins work to decommission Sable Island project,” November 9, 2017.

<sup>26</sup> *See*, Natural Gas Intelligence, “Deep Panuke Nat Gas Reserves Halved by Encana,” February 26, 2015.

<sup>27</sup> Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date September 6, 2017.

<sup>28</sup> *See*, The Chronicle Herald, “Nova Scotia’s Deep Panuke natural gas projects drying up,” May 29, 2017.

1 the only currently available supply source into MNE from the north is Repsol's Canaport  
2 LNG facility. Absent new natural gas supply sources in the Canadian Maritimes (i.e., Nova  
3 Scotia and New Brunswick), natural gas supplies will no longer be exported to the U.S.  
4 from MNE.

## 5 2. Domestic U.S. Supplies

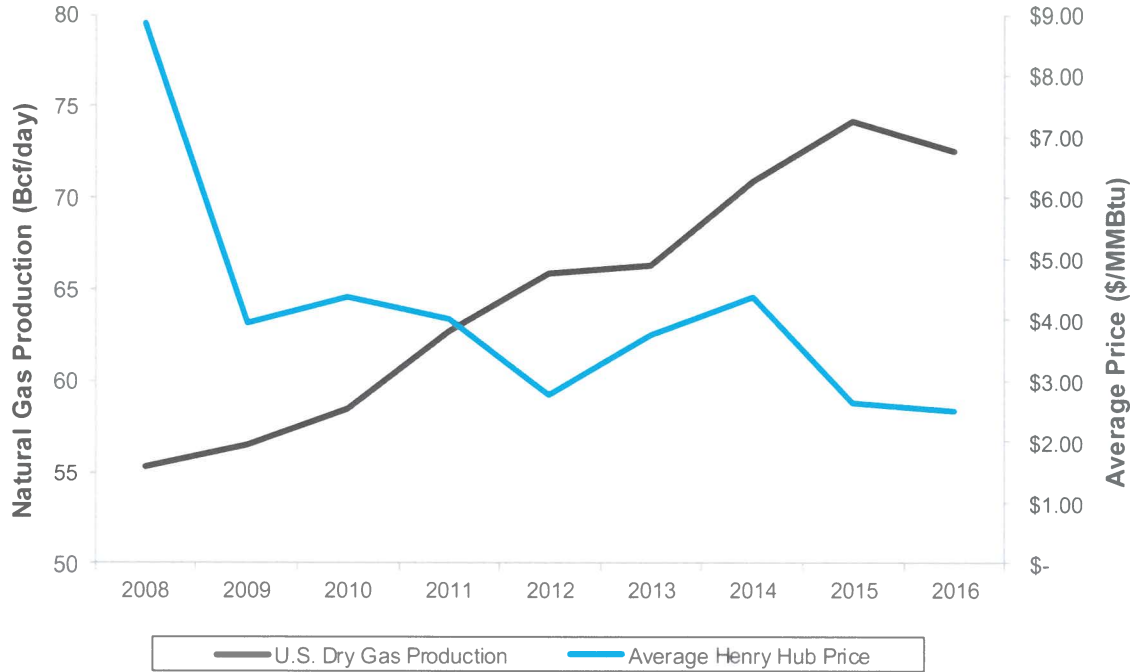
6 **Q. Please briefly discuss the trends in domestic U.S. natural gas production.**

7 A. Since 2008, there has been a significant increase in U.S. domestic natural gas production  
8 with an associated decline in natural gas prices. As illustrated in Figure 10 below, total  
9 annual natural gas production has increased from approximately 55 Bcf per day in 2008 to  
10 approximately 72 Bcf per day in 2016.<sup>29</sup> Over that same time period, the Henry Hub spot  
11 price decreased from an annual average of \$8.86 per MMBtu to \$2.52 per MMBtu.<sup>30</sup>

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<sup>29</sup> Source: U.S. Energy Information Administration, Natural Gas Dry Production, release date August 31, 2017.  
<sup>30</sup> Source: S&P Global Market Intelligence.

1 **Figure 10: Henry Hub Pricing and U.S. Domestic Natural Gas Production<sup>31</sup>**



2

3 **Q. Is the increase in U.S. domestic natural gas production expected to continue?**

4 A. Yes, it is. As illustrated in Figure 11 below, the U.S. Department of Energy/Energy

5 Information Administration (“EIA”) Annual Energy Outlook (“AEO”) projects total U.S.

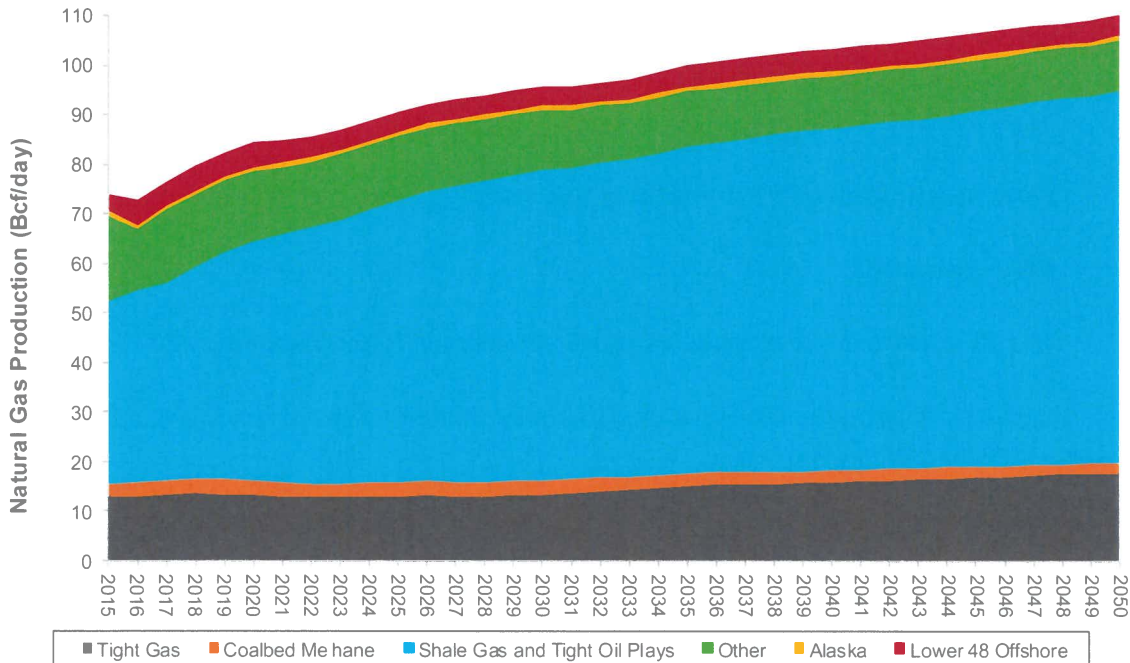
6 domestic natural gas production will reach approximately 110 Bcf per day by 2050.<sup>32</sup>

<sup>31</sup> Sources: U.S. Energy Information Administration, Natural Gas Spot and Futures Prices (NYMEX), release date August 30, 2017; and U.S. Energy Information Administration, Natural Gas Dry Production, release date August 31, 2017.

<sup>32</sup> Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, Table 14. Oil and Gas Supply, release date January 5, 2017.

1

**Figure 11: EIA U.S. Natural Gas Production Forecast<sup>33</sup>**



2

3 **Q. Are there sufficient natural gas resources to sustain that level of natural gas**  
4 **production?**

5 A. Yes, based on estimates produced by both the EIA and the Potential Gas Committee  
6 (“PGC”), a research entity affiliated with the Colorado School of Mines, there are  
7 significant reserves of domestic U.S. natural gas.

8 **Q. Please describe the estimate of natural gas resources published by the EIA.**

9 A. The EIA provides an annual estimate of Proved Reserves of natural gas, which are defined  
10 by the EIA as “the estimated quantities which analysis of geological and engineering data  
11 demonstrate with reasonable certainty to be recoverable in future years from known

<sup>33</sup> Ibid.

1 reservoirs under existing economic and operating conditions.” The EIA has increased its  
2 estimate of the total Proved Reserves in the U.S. by 46% from approximately 211 Tcf in  
3 2006 to approximately 308 Tcf in its most recent 2015 estimate.<sup>34</sup>

4 **Q. How much domestic U.S. natural gas supply is potentially recoverable based on the**  
5 **PGC estimate?**

6 A. The PGC provides a biennial estimate of technically recoverable natural gas resources in  
7 the U.S., which are additive to the EIA’s estimate of Proved Reserves.<sup>35</sup> The estimates of  
8 potential resources are classified by the PGC as Probable Resources,<sup>36</sup> Possible  
9 Resources,<sup>37</sup> and Speculative Resources.<sup>38</sup> As shown in Figure 12, the PGC estimate of  
10 total potential natural gas resources in the U.S. has increased by nearly 60% from 1,551  
11 Tcf to 2,465 Tcf between 2010 and 2016, respectively.<sup>39</sup>

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<sup>34</sup> Source: U.S. Energy Information Administration, Dry Natural Gas Proved Reserves as of 12/31 (Summary), release date December 14, 2016.

<sup>35</sup> While the EIA estimate of Proved Reserves identifies the economically recoverable resources under existing circumstances, the PGC estimate includes resources that are expected to be recoverable based on expected economic conditions, proximate resource performance, and expected technological developments. *See*, <http://potentialgas.org/what-we-do-2>, access date June 28, 2017.

<sup>36</sup> A Probable Resource is defined as a discovered but unconfirmed resource associated with known fields and field extensions, also undiscovered in new pools in both productive and nonproductive areas of known fields.  
<sup>37</sup> A Possible Resource is an undiscovered resource associated with new field/pool discoveries in known productive formations in known productive areas.

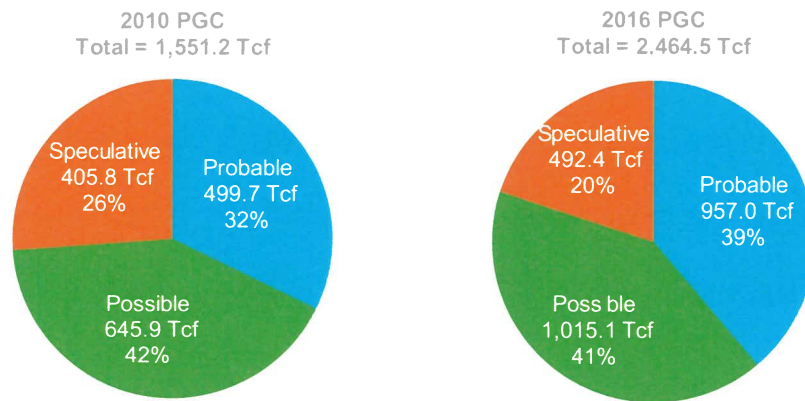
<sup>38</sup> A Speculative Resource is an undiscovered resource associated with new field/pool discoveries in as-yet nonproductive areas.

<sup>39</sup> Total resource potential represents the PGC estimates for the lower 48 U.S. states. Sources: The Potential Gas Agency, Colorado School of Mines, “Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee, December 31, 2010,” April 2011; and The Potential Gas Agency, Colorado School of Mines, “Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee, December 31, 2016,” July 2017.



1

**Figure 12: PGC Estimates of Total Potential Resources in the U.S.<sup>40</sup>**



2

3 **Q. Please provide a summary of the total U.S. domestic gas supplies based on the EIA**  
4 **and PGC estimates.**

5 **A.** As demonstrated by the EIA and PGC estimates, there has been a significant increase in  
6 U.S. reserves estimates, which supports the long-term durability of domestic U.S. natural  
7 gas supply. To provide context, assuming an annual overall U.S. natural gas consumption  
8 level of 27.5 Tcf,<sup>41</sup> the combined EIA Proved Reserves and PGC potential resource  
9 estimates would provide sufficient supply for all U.S. natural gas demand for over 100  
10 years.

<sup>40</sup> Ibid.

<sup>41</sup> Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, release date May 31, 2017. Represents the total annual consumption in the U.S. for 2016.

1                   **3. Incremental Pipeline Capacity**

2   **Q.    Has the increase in U.S. domestic gas production affected the development of natural**  
3   **gas infrastructure?**

4   A.    Yes, it has. The increase in domestic U.S. supply is also supporting the development of  
5   new natural gas infrastructure to deliver natural gas to various locations, including the  
6   Dawn Hub, Gulf Coast/Henry Hub, and to other areas of the U.S. and Canada.

7   **Q.    Are there projects to increase the pipeline deliverability into the New England region?**

8   A.    Yes, there are, although most of the volumes associated with incremental New England  
9   supply projects are targeting southern New England markets. Specifically, the shippers on  
10   certain recent projects (the Algonquin Incremental Market, TGP Connecticut Expansion,  
11   and Atlantic Bridge projects) are LDCs and end-users predominantly located in the  
12   southern New England area, with certain volumes on the Atlantic Bridge project associated  
13   with shippers in Maine and the Canadian Maritimes. These three projects will increase the  
14   total pipeline capacity into the New England region by approximately 550,000 Dth per day,  
15   with 85% of the total capacity contracted by project shippers located in southern New  
16   England.

17   **Q.    Please discuss the project development process associated with incremental pipeline**  
18   **capacity.**

19   A.    There is significant complexity and increasing lead times required for development of  
20   incremental pipeline capacity projects into the New England region. Most recently, two  
21   major projects proposed to deliver incremental natural gas supplies to the New England

1 region have faced development challenges. The Access Northeast and TGP NED Market  
2 Path projects were both major pipeline expansion projects in terms of incremental capacity,  
3 significant project facilities, and long lead times.

4 **Q. Please briefly review the Access Northeast Project.**

5 A. The proposed Access Northeast project was structured to deliver up to 900,000 Dth per day  
6 of incremental capacity via an expansion of the existing Algonquin system from New York  
7 to Massachusetts and new LNG storage facilities. An initial open season for the Access  
8 Northeast project was conducted in early 2015; however, the project was withdrawn from  
9 the FERC pre-filing review process in June 2017.<sup>42</sup>

10 **Q. Please describe the TGP NED Market Path Project.**

11 A. The TGP NED Market Path project, which has been cancelled, would have involved the  
12 construction of greenfield pipeline from Wright, New York, to Dracut, Massachusetts, to  
13 deliver up to 1,200,000 Dth per day of incremental supplies to the New England region.  
14 The open season for the TGP NED Market Path project was initially conducted in early  
15 2014, and the original in-service date for the project was November 2018, a lead time of  
16 nearly four years.<sup>43</sup>

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<sup>42</sup> Sources: Algonquin Gas Transmission, LLC, Letter Request for Approval of Pre-Filing Review for the Access Northeast Project, FERC Docket No. PF16-1-000, November 3, 2015; and Algonquin Gas Transmission, LLC, Withdrawal from Pre-Filing Review of the Access Northeast Project, FERC Docket No. PF16-1-000, June 29, 2017.

<sup>43</sup> Sources: Tennessee Gas Pipeline, L.L.C., Application for a Certificate of Public Convenience and Necessity, FERC Docket No. CP16-21-000, November 20, 2015; and Tennessee Gas Pipeline, L.L.C., Notice of Withdrawal of Certificate Application, FERC Docket No. CP16-21-000, May 23, 2016.

1 **Q. Please discuss the natural gas supply implications for the regional LDCs with respect**  
2 **to the development challenges associated with large scale pipeline projects.**

3 A. Given the complexity and long lead times needed to develop large incremental interstate  
4 pipeline capacity projects, the regional LDCs may need to increase their reliance on  
5 existing infrastructure that requires limited facilities for expansion and invest in on-system  
6 resources that address each LDC's unique circumstances.

7 **4. Imported LNG Supplies**

8 **Q. Please briefly describe the LNG importation facilities in New England.**

9 A. There are three import LNG terminals located in New England: ENGIE's LNG facility in  
10 Everett, Massachusetts, and two off-shore LNG facilities near Cape Ann, Massachusetts  
11 (ENGIE's Neptune LNG facility<sup>44</sup> and Excelerate Energy's Northeast Gateway Deepwater  
12 Port). In addition, the New England market has access via the MNE-US system to natural  
13 gas supplies from the Canaport LNG facility, which is a partnership between Repsol (75%)  
14 and Irving Oil (25%).<sup>45</sup> Table 2 below summarizes the existing capabilities of the four  
15 LNG importation facilities in the New England/Maritimes Canada region.

---

<sup>44</sup> In early 2017, Neptune LNG filed for a permit to commence decommissioning work on the facility. *See*, U.S. Army Corps of Engineers, "Neptune LNG seeks permit to work in U.S. waters to decommission deepwater LNG port off Marblehead," February 28, 2017.

<sup>45</sup> The Brunswick Pipeline connects the Canaport LNG facility to MNE-US at Calais, Maine.

**Table 2: Regional LNG Importation Facilities<sup>46</sup>**

| LNG Import Facility | Storage Capacity | Vaporization Capacity |
|---------------------|------------------|-----------------------|
| ENGIE Everett LNG   | 3.4 Bcf          | 1.035 Bcf/day         |
| ENGIE Neptune LNG   | n/a              | 0.4 Bcf/day           |
| Northeast Gateway   | n/a              | 0.8 Bcf/day           |
| Canaport LNG        | 10 Bcf           | 1.0 Bcf/day           |

**Q. Are LNG imports a predominant source of natural gas supply for the U.S. in general?**

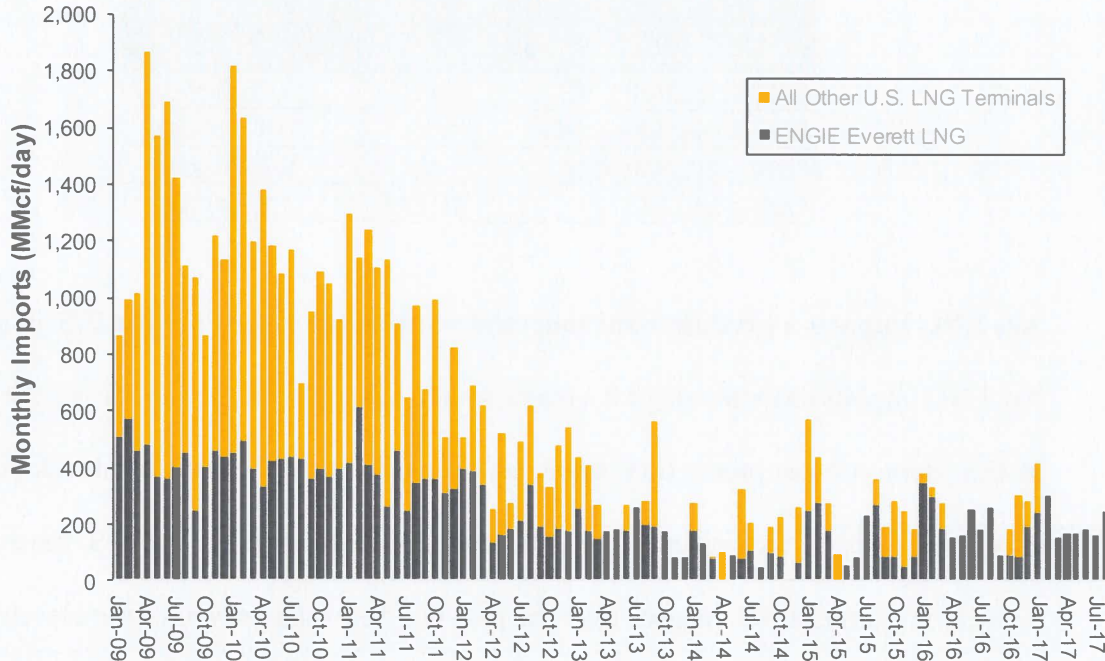
A. No, LNG imports are generally not a major source of supply for the U.S. Given the increase in U.S. domestic gas production, there has been a trend in the U.S. for developing LNG export facilities. In fact, most of the LNG importation facilities in the U.S. have not been actively importing LNG cargoes over the past few years, and seven of the eleven existing U.S. LNG import terminals are in various stages of developing LNG export capability.<sup>47</sup> As shown in Figure 13 below, the ENGIE Everett LNG facility in New England has accounted for the majority of imported LNG volumes to the U.S. since 2013.

<sup>46</sup> Source: FERC, North American LNG Import/Export Terminals: Existing, release date May 1, 2017.

<sup>47</sup> Sources: FERC, North American LNG Import/Export Terminals: Existing, release date May 1, 2017; and FERC, North American LNG Import/Export Terminals: Approved, release date May 1, 2017.

1

**Figure 13: Imported LNG Volumes to U.S.<sup>48</sup>**



2

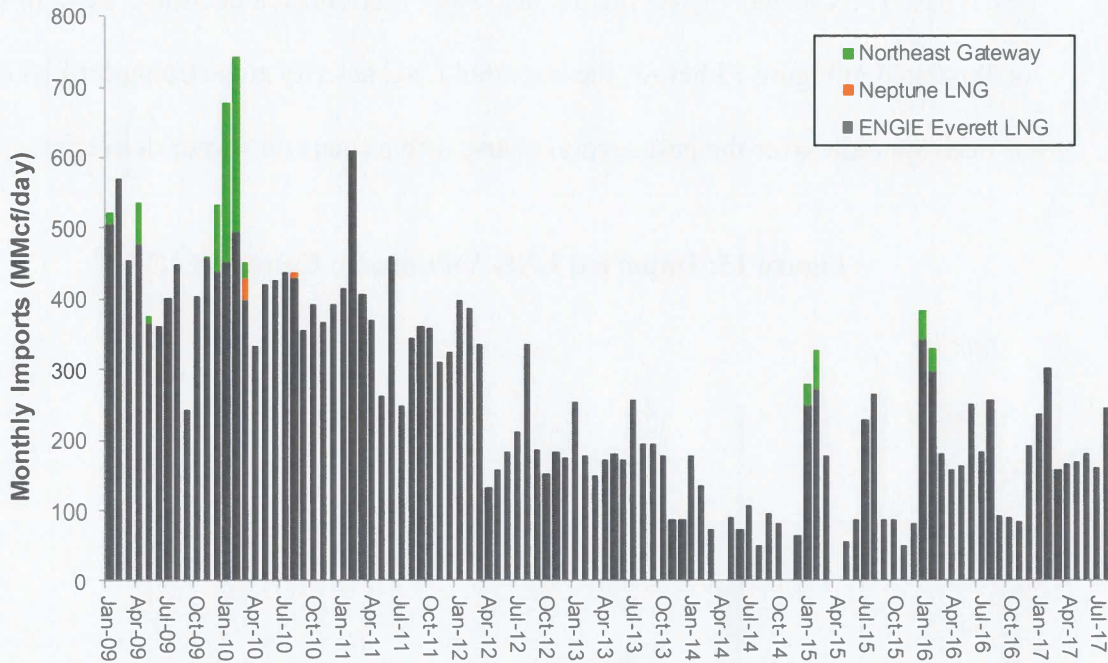
3 **Q. Please discuss trends in imported LNG volumes to the New England importation**  
4 **facilities.**

5 A. As illustrated in Figure 14 below, the two off-shore LNG importation facilities, Northeast  
6 Gateway and Neptune LNG, have had limited activity since commencing service in 2009  
7 and 2010, respectively, and the ENGIE Everett LNG facility has become more winter  
8 season focused.

<sup>48</sup> Source: U.S. Department of Energy, LNG Annual and Monthly Reports, accessed on October 25, 2017.

1

**Figure 14: Imported LNG Volumes to New England<sup>49</sup>**



2

3 In addition, as shown in Figure 14, there has been significant variability in the volumes of  
4 LNG imported to the region. Over the past four split-years (2013/14 through 2016/17),  
5 there has been less baseload volumes and more winter-focused deliveries. In the peak  
6 winter months, total imported LNG volumes to New England ranged from an average of  
7 less than 65 MMcf per day to approximately 340 MMcf per day over the past four winter  
8 periods (i.e., winters of 2013/14 through 2016/17).<sup>50</sup>

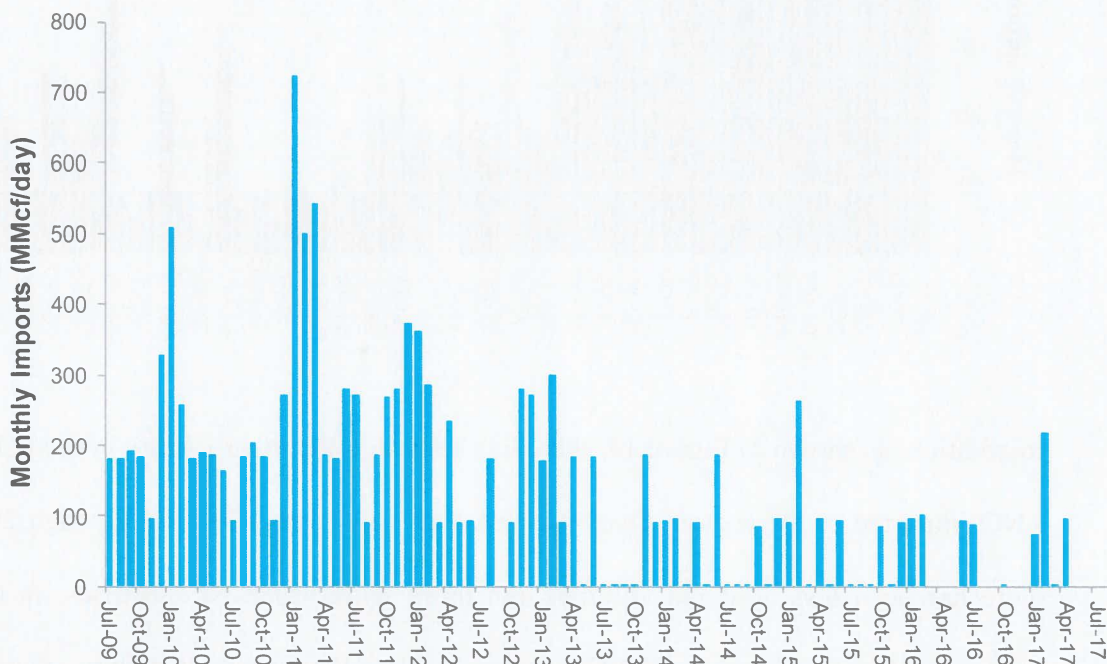
<sup>49</sup> Ibid.  
<sup>50</sup> Ibid.

1 **Q. Has the Canaport LNG terminal experienced similar trends in LNG import activity?**

2 A. Yes, it has. The Canaport LNG facility also has experienced a declining trend in volumes.

3 As illustrated in Figure 15 below, the imported LNG activity at the Canaport LNG terminal  
4 has been sporadic over the past several years, with a focus on winter deliveries.

5 **Figure 15: Imported LNG Volumes to Canaport LNG<sup>51</sup>**



6

7 **Q. What are the likely market issues that have influenced imported LNG volumes to the**  
8 **New England/Maritimes Canada region?**

9 A. Since the LNG market is a global market, the New England/Maritimes Canada region must  
10 compete with international markets for imported LNG supplies. The volume of LNG  
11 imported into the region is influenced by various factors, including the demand for LNG

<sup>51</sup> Source: National Energy Board of Canada, LNG - Shipment Details, accessed on October 25, 2017.



1 in alternative markets, and the need for the New England market to pull the supply by  
2 contracting for imported LNG volumes.

3 **C. Summary of Regional Natural Gas Market Dynamics**

4 **Q. Please summarize the current regional natural gas demand and supply trends and the**  
5 **implications for LDCs in terms of natural gas supply strategy and planning.**

6 A. The New England region is currently faced with increasing demand for natural gas by both  
7 the traditional LDC and power generation segments and significant natural gas supply and  
8 capacity challenges, particularly during the winter period. During the winter periods when  
9 the demand from the traditional LDC segment is generally higher due to the heat sensitive  
10 nature of the LDC load requirements, there may be competition from the power generation  
11 segment for winter gas supplies leading to higher and more volatile New England natural  
12 gas price indices.

13 With respect to natural gas supplies, there are three main challenges impacting the long-  
14 term availability and feasibility of natural gas resource options to serve the region. First,  
15 there will likely be limited to no natural gas supplies from off-shore Nova Scotia (i.e.,  
16 SOEP and Deep Panuke) to the New England region by 2020. Second, the New England  
17 region will likely need to compete with alternative markets for imported LNG supplies.  
18 Finally, there is significant complexity and long lead times associated with the  
19 development of new incremental pipeline capacity projects into the region and, thus,  
20 regional LDCs may need to rely on existing infrastructure that require limited facilities for

1 expansion, and invest in on-system resources that address each LDC's unique  
2 circumstances.

3 These market dynamics and regional supply challenges faced by the New England LDCs  
4 highlight the importance of the LDC's role in planning, procuring, and managing a  
5 portfolio of resources to meet customer requirements. The LDC's natural gas supply  
6 strategy and planning must account for the present and future market conditions, as well as  
7 its unique situation, to ensure reliable supplies at a reasonable cost for its customers.

8 **IV. REVIEW OF ENERGYNORTH'S NATURAL GAS DEMAND**

9 **Q. Please discuss the Company's growth in natural gas customers since the acquisition**  
10 **of EnergyNorth by Liberty Energy (NH).**

11 A. As discussed in the Fleck/DaFonte Testimony, since the transfer of ownership of  
12 EnergyNorth from National Grid USA to Liberty Energy (NH),<sup>52</sup> EnergyNorth has  
13 experienced growth in its number of natural gas customers as a result of an increased focus  
14 on sales and marketing. The number of EnergyNorth customers has increased by 8% from  
15 approximately 85,500 customers in 2012 to approximately 91,000 customers in 2017.<sup>53</sup>  
16 Notably, as a result of the Company's sales and marketing efforts, there was an increase of  
17 approximately 1,400 customers between 2014 and 2015 and an increase of approximately  
18 1,800 customers between 2015 and 2016 as illustrated in Figure 16 below.

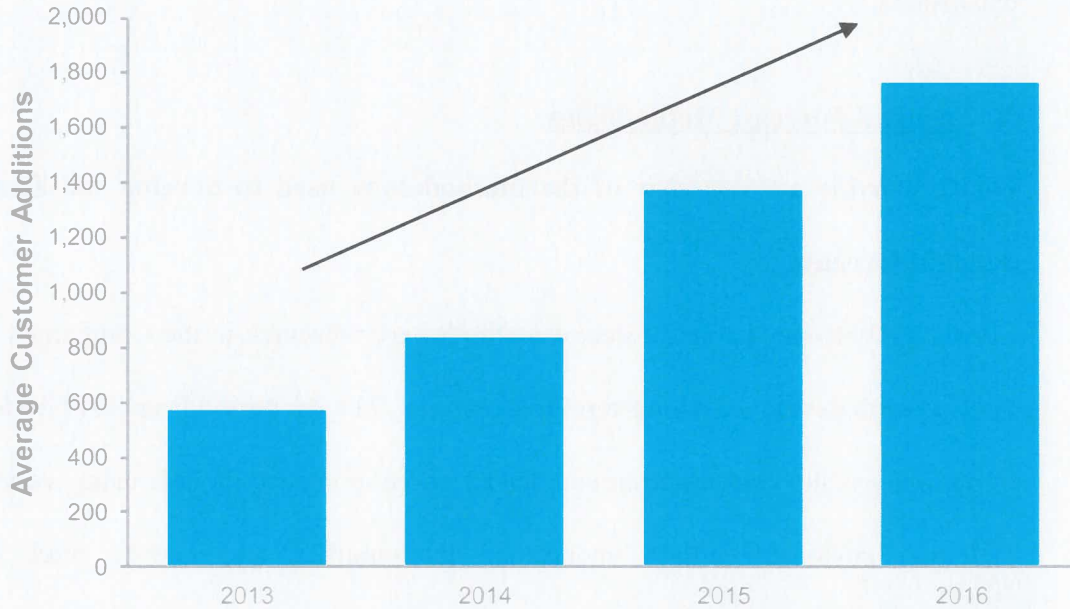
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<sup>52</sup> The Commission approved the transfer of ownership as part of a settlement agreement between National Grid USA and Liberty Energy (NH). *See*, Order No. 25,370 (May 30, 2012).

<sup>53</sup> Represents the average number of sales and capacity assigned transportation customers for the fiscal year period from April to March.

1

**Figure 16: EnergyNorth Growth in Customers<sup>54</sup>**



2

3

The increase in EnergyNorth's natural gas customers has resulted in an overall increase in natural gas demand.

4

5 **Q. Does EnergyNorth expect the demand for natural gas will continue to grow?**

6 **A.** Yes, it does. The demand forecast developed by EnergyNorth for this filing shows a

7 continued increase in the number of natural gas customers, as well as an increase in the

8 overall demand for natural gas. The growth in demand for natural gas is supported by: (1)

9 EnergyNorth's continued focus on customer growth in its existing service territories; (2)

10 incremental load requirements for certain customers that are not captured by the

<sup>54</sup> Represents the average number of sales and capacity assigned transportation customers for the fiscal year period from April to March.

1 Company's econometric forecast models; and (3) additional growth from service area  
2 expansions.

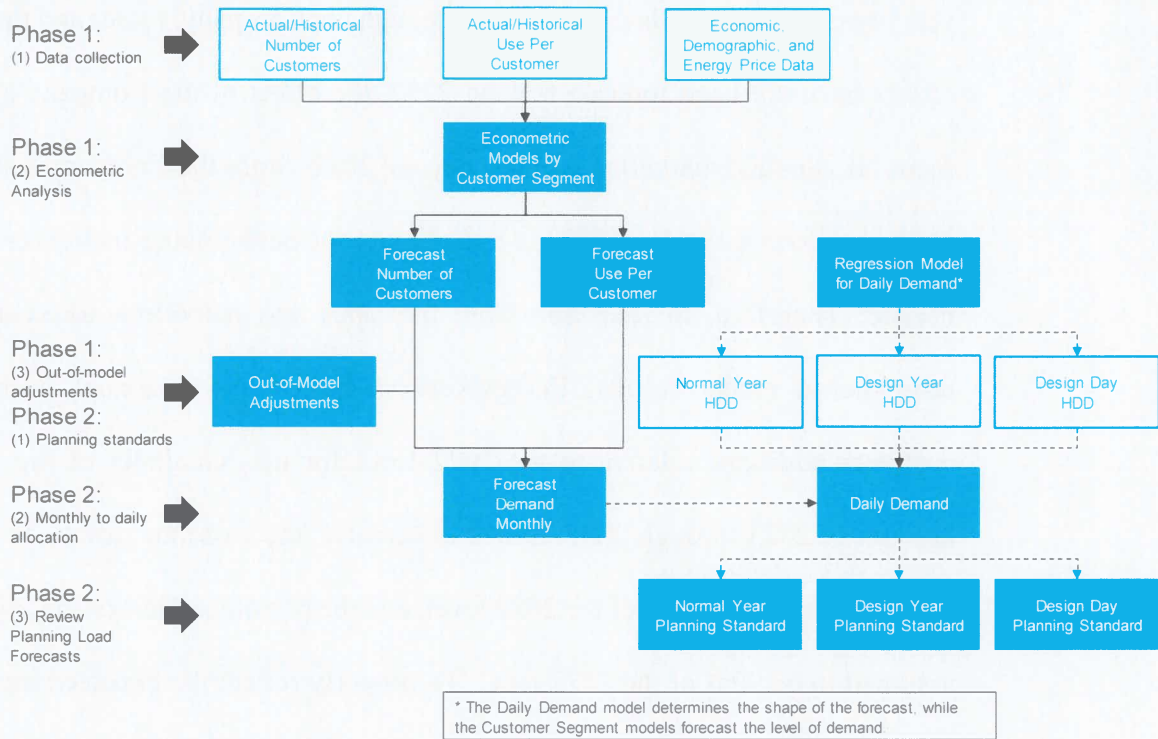
3 **A. Demand Forecast Methodology**

4 **Q. Please provide an overview of the methodology used to develop the EnergyNorth**  
5 **demand forecast.**

6 A. Consistent with the demand forecast methodology presented in the Company's 2017 IRP,  
7 EnergyNorth developed a long-term forecast (i.e., 21-year period from 2017/18 to 2037/38)  
8 of natural gas demand requirements based on econometric models using various inputs,  
9 including customer billing, economic, demographic, and energy price data. The  
10 methodology used to develop the demand forecast in this instant filing is the same process  
11 used for the Company's 2017 IRP filing. A flow chart illustrating the overall demand  
12 forecast methodology is provided in Figure 17 below. More detailed information regarding  
13 the demand forecast methodology is provided in the Company's 2017 IRP filing.

1

**Figure 17: EnergyNorth Demand Forecast Methodology**



2

3 **Q. How did the Company extend the demand forecast beyond the five-year period of**  
4 **2017/18 to 2021/22 contained in the 2017 IRP?**

5 **A.** For Phase 1 of the demand forecast process (see Figure 17 above), the Company used the  
6 same econometric (i.e., regression) models by customer segment developed in the 2017  
7 IRP, and extended the forecast period through 2037/38 using the economic, demographic,  
8 and energy price data provided by Moody’s and EIA. Next, the Company extended the out-  
9 of-model adjustments for its existing and new service territories using the approach  
10 outlined below:

- 11 • Existing Service Territory – As discussed in detail in the 2017 IRP, the out-of-  
12 model adjustment for growth within the Company’s existing service territory is

1 based on the sales and marketing group's planned customer additions for the six-  
2 year period from 2017 through 2022. Although the Company's sales and marketing  
3 efforts have not been forecast beyond 2022, the effect of the Company's current  
4 focus on sales and marketing will last beyond 2022. Since the Company's sales and  
5 marketing forecast ends in 2022, a transition to the econometric model results was  
6 needed. Therefore, to transition from the sales and marketing forecast to the  
7 econometric model results, EnergyNorth assumed a 5% annual decrease in  
8 customer additions relative to the 2022 level for the remainder of the forecast  
9 horizon of 2023 through 2038. Stated differently, the customer additions in 2023  
10 were assumed to be 95% of the 2022 level, and the customer additions in 2024 were  
11 assumed to be 90% of the 2022 level. To properly reflect the expected increase in  
12 customer additions, the annual customer growth associated with the econometric  
13 forecast was compared to the calculated annual customer addition estimates during  
14 the transition period by customer segment. Where the annual transition period  
15 estimates for a customer segment were higher than the econometric forecast of  
16 customer additions, the customer additions of the econometric forecast were  
17 adjusted by the difference between the transition period estimates and the  
18 econometric forecast of annual customer additions. For years in which the  
19 econometric forecast of customer additions was equal to or above the estimated  
20 customer additions for a customer segment, the econometric forecast was relied on  
21 with no adjustment. The customer additions were then multiplied by the projected

1 use per customer values from the Company's econometric models for the respective  
2 customer segment to determine the projected volumes.

- 3 • New Service Territories – As discussed in the 2017 IRP, the Company developed  
4 an out-of-model adjustment for its expansion plans to new service areas, which  
5 includes the Pelham and Windham communities,<sup>55</sup> and the communities along the  
6 proposed Granite Bridge Pipeline (Epping, Raymond, and Candia). Since these new  
7 service areas have no historical data on customer additions or usage pattern, the  
8 Company relied on the sales and marketing group's planned customer additions for  
9 these new service areas for the six-year period from 2017 through 2022, and  
10 assumed the number of customer additions for the remainder of the forecast (i.e.,  
11 2023 through 2038) would be equivalent to the 2022 level.<sup>56</sup> The customer  
12 additions were then multiplied by the projected use per customer values from the  
13 Company's econometric models for the respective customer segment to determine  
14 the projected volumes.

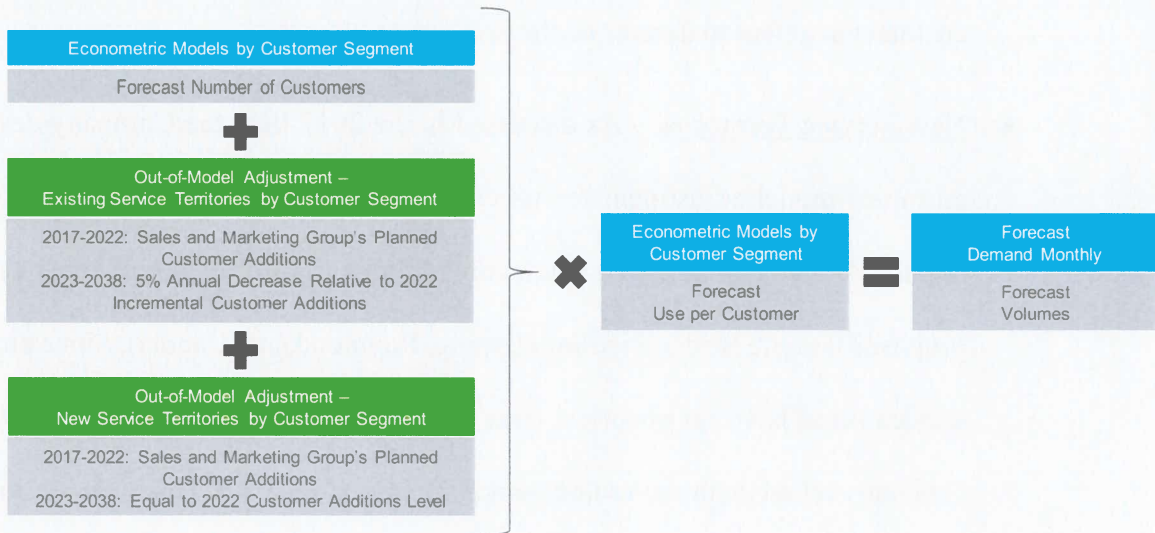
15 Figure 18 below summarizes the various out-of-model adjustments to the results of the  
16 econometric models in the Base Case demand forecast.

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<sup>55</sup> The Commission previously approved the Company's expansion plans to serve the towns of Windham and Pelham in Order No. 25,987 (Feb. 8, 2017).

<sup>56</sup> As a result, the projected saturation level for the new service territories is estimated be approximately 40% by the end of the forecast horizon (i.e., 2037/38).

1 **Figure 18: EnergyNorth Base Case Demand Forecast**



3 **Q. Did the Company develop various demand scenarios?**

4 A. Yes, it did. EnergyNorth developed demand forecasts under a range of weather conditions.  
5 Specifically, the demand forecast reflects three weather planning periods: (1) Normal Year,  
6 or the demand that is likely to occur; (2) Design Day, or the highest single day demand  
7 levels that the Company is projected to supply; and (3) Design Year that represents demand  
8 under extended cold weather conditions.

9 **Q. Please describe the process used to develop the Normal Year, Design Year, and Design  
10 Day planning standards.**

11 A. The Company used the same analytical approaches described in the 2017 IRP to develop  
12 the weather planning periods. EnergyNorth’s analyses resulted in a Normal Year of 6,325  
13 heating degree days (“HDDs”), a Design Year of 6,869 HDDs, and a Design Day of 71  
14 HDDs.



1 **Q. Did the demand forecast include the effects of the Company's energy efficiency plan?**

2 A. Yes, it did. The volumetric results of the demand forecast (i.e., econometric models plus  
3 out-of-model adjustments) were reduced by energy efficiency savings to determine the  
4 Company's net demand requirements. The energy efficiency savings were assumed to be  
5 equal to those estimated by the Company in the 2018-2020 New Hampshire Statewide  
6 Energy Efficiency Plan filed with the Commission in Docket No. DE 17-136. Using the  
7 same approach defined in the 2017 IRP for energy efficiency savings beyond 2020, the  
8 Company assumed the percentage of residential energy efficiency volumes relative to  
9 residential firm demand continued to be equivalent to the 2020 level through the end of the  
10 forecast horizon. The same assumption was made for energy efficiency savings for C&I  
11 customers for the 2021 to 2038 time period.

12 **Q. Please describe the Company's process for allocating the net monthly demand**  
13 **requirements to daily demand requirements.**

14 A. The Company allocated the net monthly demand forecast into daily requirements to model  
15 its resources and requirements with its SENDOUT® linear programming software  
16 modeling package. In addition, given that the contract and operational parameters of the  
17 gas supply portfolio (e.g., contractual maximum transportation quantities or maximum  
18 storage withdrawal volumes) are modeled as daily values in SENDOUT®, the monthly  
19 demand requirements also must be allocated into daily values. As detailed in the 2017 IRP,  
20 that monthly demand allocation was accomplished by using a daily demand model, which  
21 was developed by the Company using a regression model based on daily sendout and

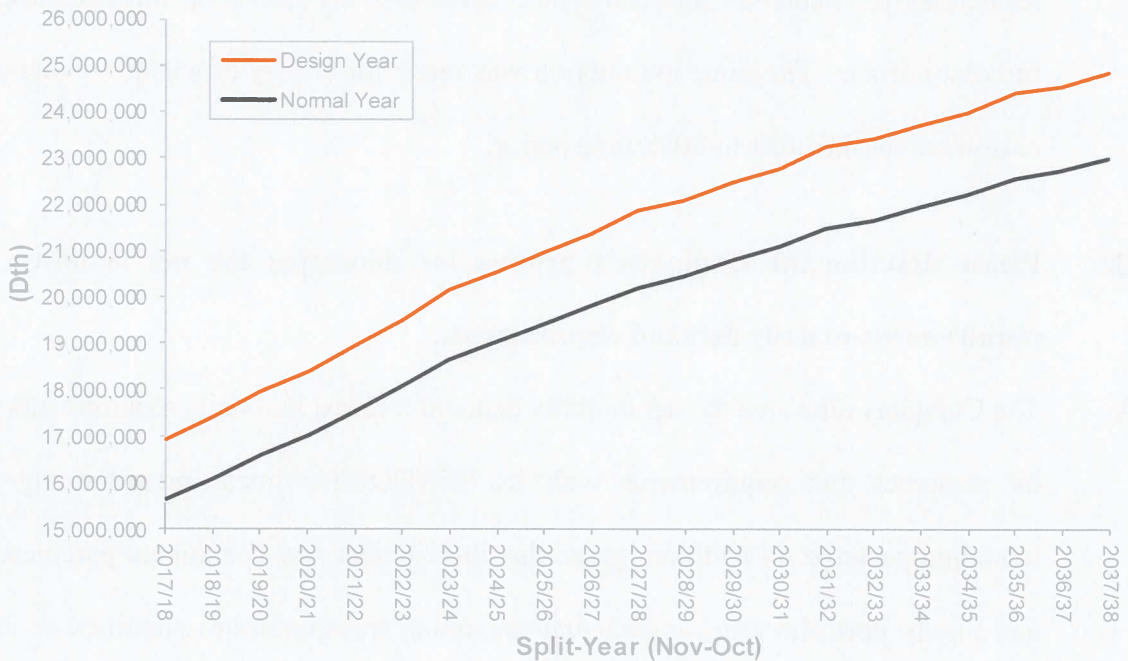
1 temperature. The daily demand model determines the daily shape of the demand forecast,  
2 while the customer segment models forecast the level of demand.

3 **B. Results of the EnergyNorth Demand Forecast**

4 **Q. Please summarize the results of the Company's demand forecast.**

5 **A.** Figures 19 and 20 below depict the results of EnergyNorth's Base Case demand forecast  
6 for Normal Year, Design Year, and Design Day over the 21-year forecast horizon.

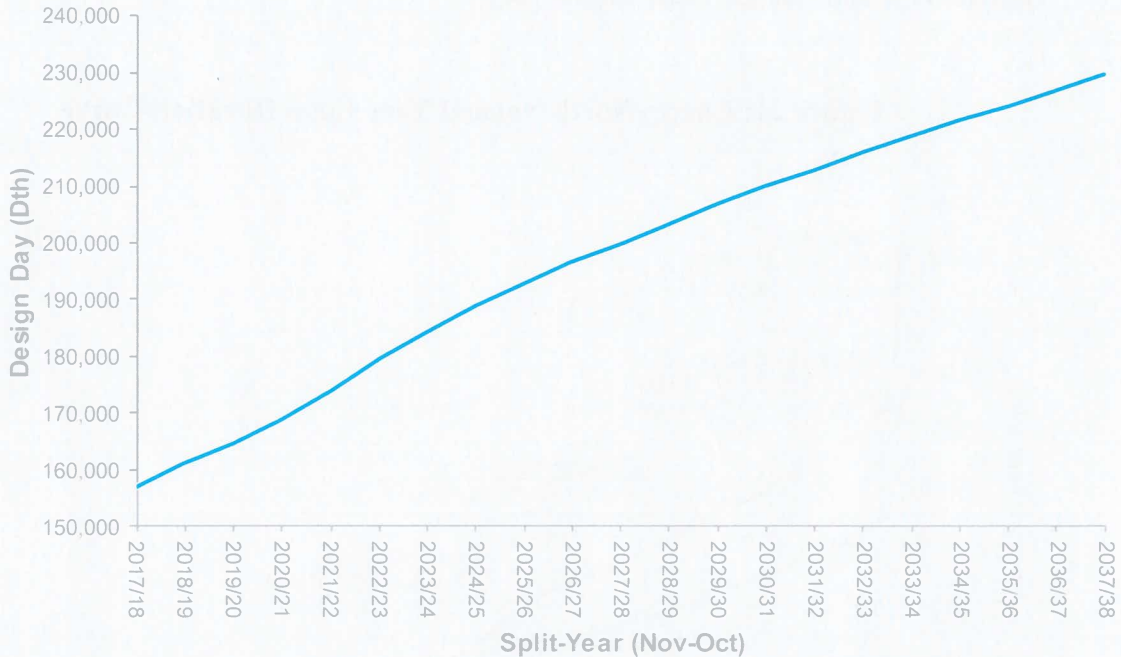
7 **Figure 19: EnergyNorth Normal Year and Design Year Demand Forecast**



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**Figure 20: EnergyNorth Design Day Demand Forecast**



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The results of the Company's demand forecast show an increase in natural gas demand requirements over the forecast horizon. Specifically, over the 21-year forecast horizon from 2017/18 to 2037/38, the incremental demand requirement is approximately 7.4 million Dth for Normal Year and 7.9 million Dth for Design Year. With respect to Design Day, the incremental Design Day demand requirement is 72,768 Dth by 2037/38.

4

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**Q. Please discuss EnergyNorth's projected demand profile.**

7

A. To analyze the Company's projected demand profile, EnergyNorth developed a load duration curve analysis. Load duration curves were developed by re-sorting the projected daily demand requirements by highest load day to lowest load day for certain years in the

8

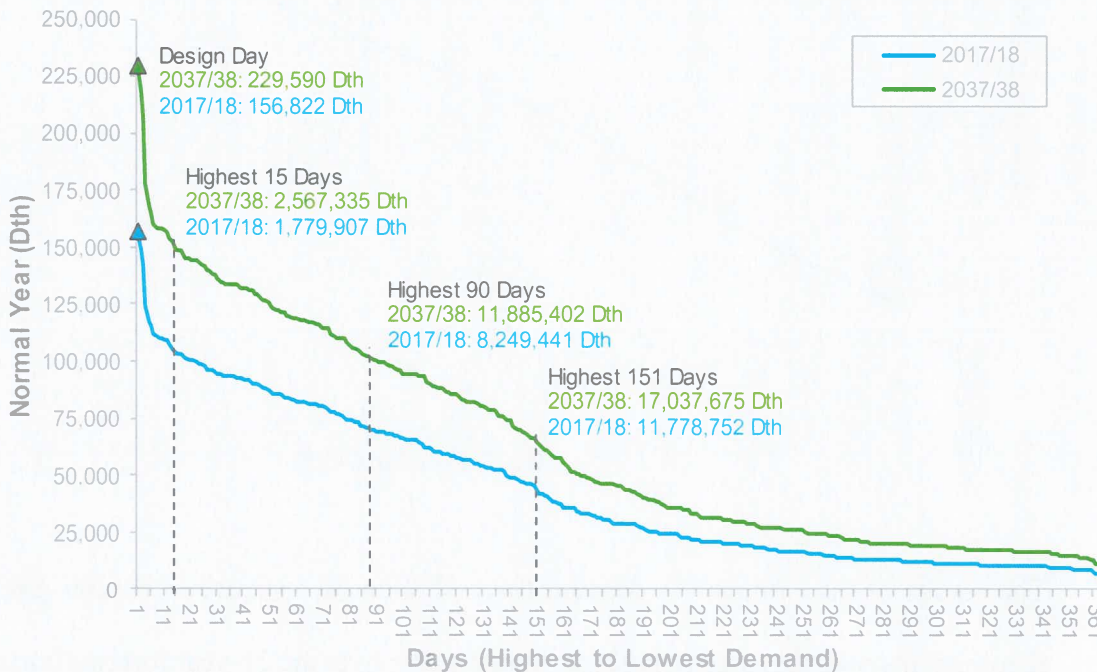
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1 forecast horizon. Figures 21 and 22 below illustrate the load duration curve analysis for  
2 Normal Year and Design Year, respectively.

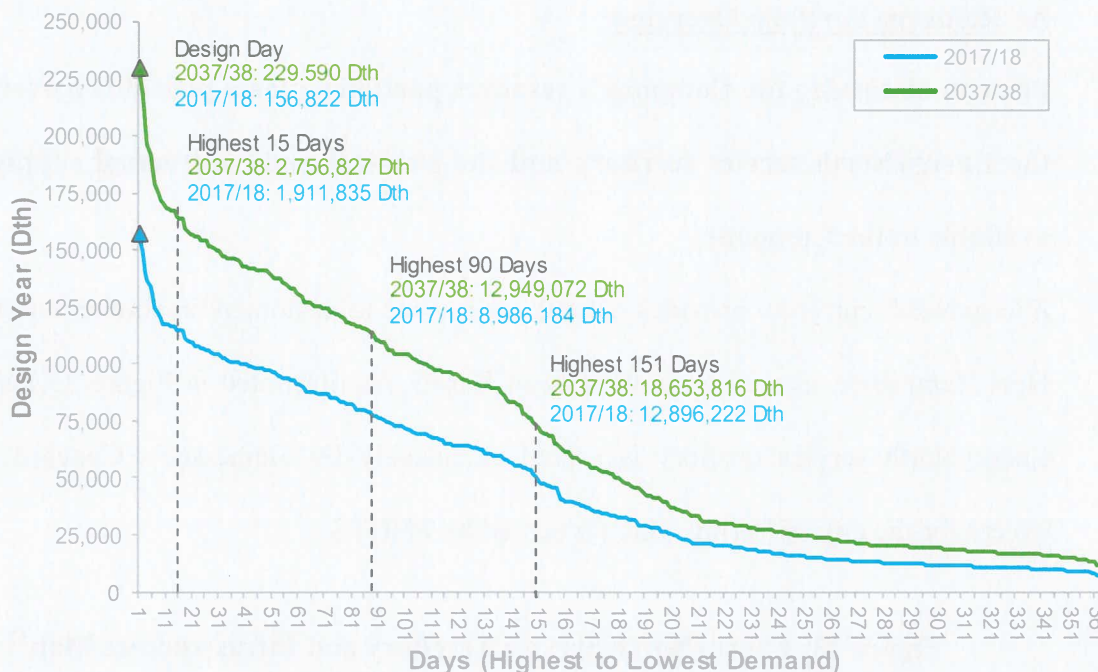
3 **Figure 21: EnergyNorth Normal Year Load Duration Curve**



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**Figure 22: EnergyNorth Design Year Load Duration Curve**



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As depicted in Figures 21 and 22, EnergyNorth has significant peak day and winter period demand requirements. The Company's Design Day demand grows by 72,768 Dth over the 21-year forecast horizon to a total of 229,590 Dth by 2037/38. On the highest 15 demand days, the total demand requirement increases by nearly 800,000 Dth for Normal Year and 840,000 Dth for Design Year between 2017/18 and 2037/38. Focusing on the highest 90 demand days (the peak winter period), the total Normal Year and Design Year demand requirement increases by approximately 3.6 million Dth and 3.9 million Dth, respectively. Finally, the total demand for the highest 151 demand days (the winter period) increases by over 5.2 million Dth and 5.7 million Dth between 2017/18 and 2037/38 for Normal Year and Design Year, respectively.

12

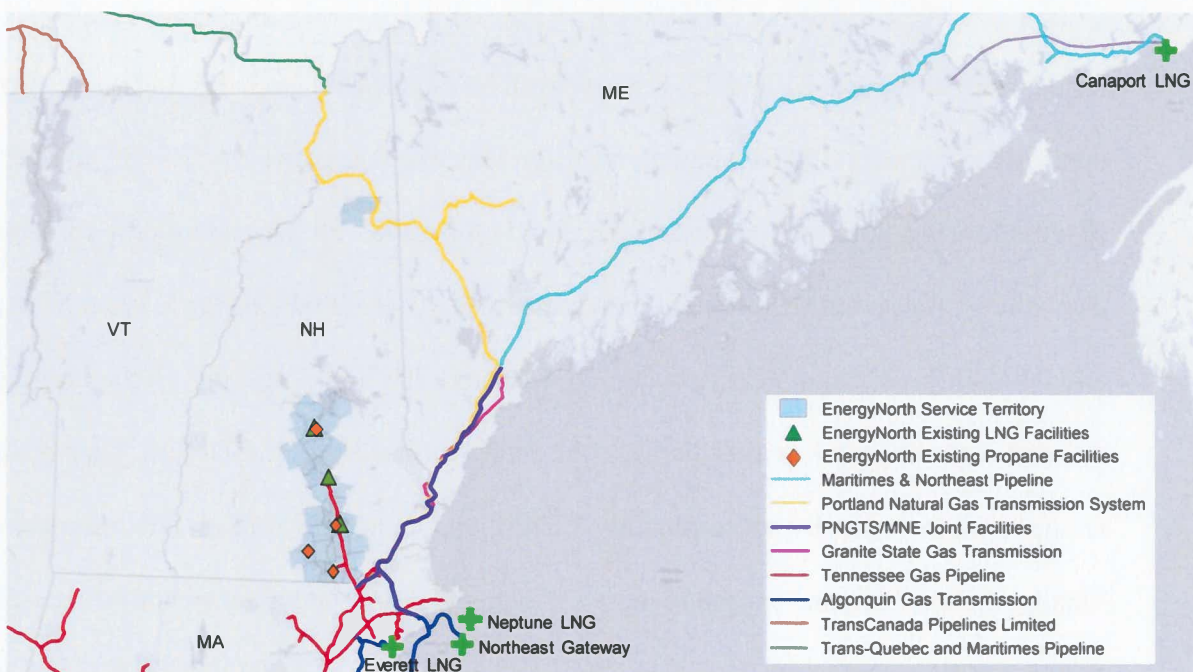
1 **V. REVIEW OF ENERGNORTH'S CURRENT NATURAL GAS PORTFOLIO**

2 **A. Resource Portfolio Overview**

3 **Q. Prior to discussing the Company's resource portfolio, please provide an overview of**  
4 **the EnergyNorth service territory and the physical and contractual supply assets**  
5 **available to the Company.**

6 A. EnergyNorth currently provides natural gas service to customers in southern and central  
7 New Hampshire, as well as in the city of Berlin. As illustrated in Figure 23 below, the  
8 EnergyNorth service territory is served exclusively by Tennessee's Concord Lateral,  
9 except for the city of Berlin, which is served by PNGTS.

10 **Figure 23: EnergyNorth Service Territory and Infrastructure Map<sup>57</sup>**



11  
<sup>57</sup> Source: S&P Global Market Intelligence [modified by ScottMadden].

1 As shown by Figure 23 above, the upstream natural gas supply options available to the  
2 Company are determined based on the ability of a particular resource to access Tennessee.  
3 Stated differently, since Tennessee is the only feed to almost all of the EnergyNorth service  
4 territory, it is currently determinative with respect to upstream supply decisions.

5 **Q. Please summarize the current EnergyNorth natural gas supply portfolio.**

6 A. To meet Design Day and Design Year sendout requirements, the Company's portfolio is  
7 comprised of the following resources: (1) long-haul and short-haul transportation capacity;  
8 (2) underground storage; and (3) on-system peak-shaving LNG and propane facilities. A  
9 summary of EnergyNorth's current resource portfolio, with associated contract expiration  
10 dates, is provided in Table 3 below.

1

**Table 3: EnergyNorth Design Day Resources<sup>58</sup>**

| Gas Supply  | Contract Entity | Contract Number | Contract End Date | Contract MDQ (Dth/day) |
|---|-----------------|-----------------|-------------------|------------------------|
| <b>Canadian Supply</b>  |                 |                 |                   |                        |
| East Hereford   | PNGTS           | FT (#1999-001)  | 11/30/2032        | 1,000                  |
| Dawn  | Union Gas       | FT (#M12200)    | 10/31/2022        | 4,092                  |
|   | TCPL            | FT (#41232)     | 10/31/2022        | 4,047                  |
|   | Iroquois        | RTS (#470-01)   | 11/1/2022         | 4,047                  |
|   | Tennessee       | FT-A (#95346)   | 11/30/2021        | 4,000                  |
| Niagara   | Tennessee       | FT-A (#2302)    | 10/31/2020        | 3,122                  |
| <b>U.S. Domestic Supply</b>                                     |                 |                 |                   |                        |
| Dracut  | Tennessee       | FT-A (#42076)   | 10/31/2020        | 20,000                 |
| Dracut  | Tennessee       | FT-A (#72694)   | 10/31/2029        | 30,000                 |
| Gulf (Zone-0 100 Leg)   | Tennessee       | FT-A (#8587)    | 10/31/2020        | 7,035                  |
| Gulf (Zone-1 100 Leg)   | Tennessee       | FT-A (#8587)    | 10/31/2020        | 523                    |
| Gulf (Zone-1 800 Leg)   | Tennessee       | FT-A (#8587)    | 10/31/2020        | 4,536                  |
| Gulf (Zone-1 500 Leg)   | Tennessee       | FT-A (#8587)    | 10/31/2020        | 9,502                  |
| Storage (Zone 4)  | Tennessee       | FT-A (#8587)    | 10/31/2020        | 3,811                  |
|   | Tennessee       | FT-A (#8587)    | 10/31/2020        | 25,407                 |
| Storage   | Tennessee       | FS-MA (#523)    | 10/31/2020        | 21,844                 |
|   | Tennessee       | FT-A (#632)     | 10/31/2020        | 15,265                 |
| Storage   | Honeoye         | SS-NY (#11234)  | 3/31/2020         | 1,957                  |
| Storage   | Dominion        | GSS (#300076)   | 3/31/2021         | 934                    |
| Storage   | National Fuel   | FSS (#O02357)   | 3/31/2019         | 6,098                  |
|   | National Fuel   | FST (#N02358)   | 3/31/2019         | 6,098                  |
|   | Tennessee       | FT-A (#11234)   | 10/31/2020        | 9,039                  |
| <b>Total Firm Transportation</b>                                |                 |                 |                   | <b>107,833</b>         |
| LNG Daily Operational Capacity (Concord/Manchester/Tilton)      |                 |                 |                   | 12,600                 |
| Propane Daily Deliverability (Amherst/Manchester/Nashua/Tilton) |                 |                 |                   | 34,600                 |
| <b>TOTAL DESIGN DAY RESOURCES</b>                               |                 |                 |                   | <b>155,033</b>         |

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As illustrated in Table 3 above, EnergyNorth has firm transportation contracts on Tennessee (106,833 Dth per day) and PNGTS (1,000 Dth per day) to provide a total daily deliverability of 107,833 Dth per day to its city-gate stations from three natural gas supply sources (Canadian supply, domestic U.S. supply, and underground storage in Pennsylvania

<sup>58</sup>

Please note that certain contracts are organized by path, with only the contract that ultimately delivers to EnergyNorth included in the total resource calculation.



1 and New York). In addition, the Company owns three LNG facilities in Concord,  
2 Manchester, and Tilton with a combined daily operational vaporization and storage  
3 capacity of approximately 12,600 Dth. Finally, there are three propane facilities located in  
4 Manchester, Nashua, and Tilton that are directly connected to the Company's distribution  
5 system, and a fourth "satellite" propane facility in Amherst.<sup>59</sup> The propane facilities have  
6 a combined vaporization rate of approximately 34,600 Dth per day and storage capacity of  
7 approximately 108,397 Dth. In total, EnergyNorth has Design Day resources of  
8 approximately 155,033 Dth per day.

9 **B. Transportation Capacity**

10 **Q. Please describe the existing pipeline delivery options to the EnergyNorth service**  
11 **territory.**

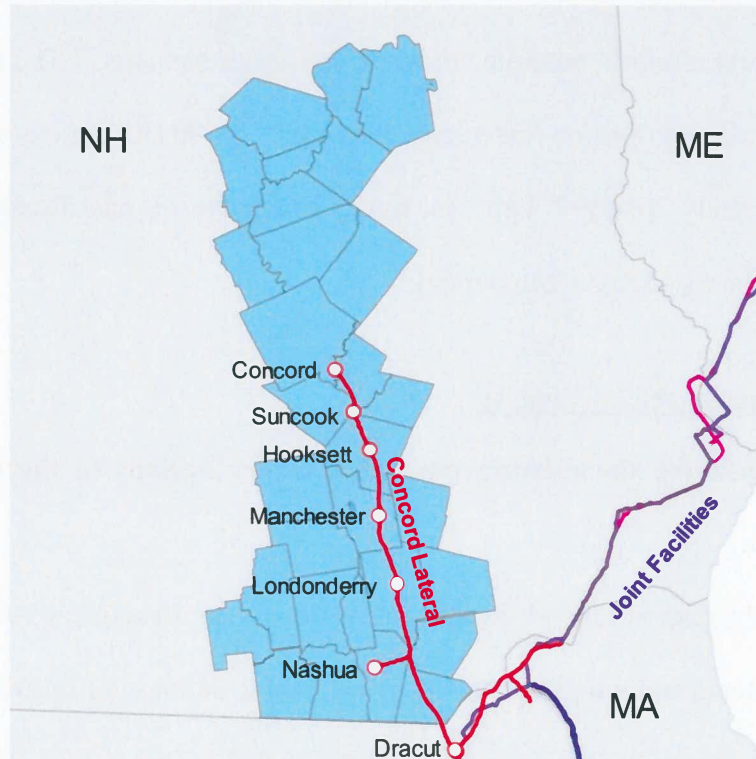
12 A. The TGP Concord Lateral, which was originally constructed in 1951, is the primary and,  
13 for all intents and purposes, the only feed for the delivery of upstream gas supplies to the  
14 EnergyNorth service territory. Approximately 99% of the pipeline deliveries (106,833 Dth  
15 per day of the 107,833 Dth per day of total firm transportation contract MDQ) to the  
16 EnergyNorth service territory are from the TGP Concord Lateral, while only 1% (1,000  
17 Dth per day) of the pipeline deliveries are from PNGTS, which directly serves the city of  
18 Berlin. With respect to the physical path of the TGP Concord Lateral, it originates near  
19 Dracut, where Tennessee has interconnections with MNE-US and PNGTS, and traverses

---

<sup>59</sup> The propane facility in Amherst is used solely for storage.

1 north along Interstate 93 terminating near Concord, New Hampshire. Figure 24 is an  
2 illustrative map of the TGP Concord Lateral.

3 **Figure 24: Illustrative TGP Concord Lateral Map<sup>60</sup>**



4  
5 **Q. Please summarize the upstream resources in EnergyNorth's existing supply portfolio.**

6 **A.** Table 4 below is a summary of the Company's existing firm transportation capacity (as  
7 provided in Table 3 above) by upstream supply source.

<sup>60</sup> Source: S&P Global Market Intelligence [modified by ScottMadden and EnergyNorth].

**Table 4: EnergyNorth Upstream Supply Sources**

| Gas Supply                       | Contract MDQ<br>(Dth/day) | % of Total<br>Resources |
|----------------------------------|---------------------------|-------------------------|
| Canadian Supply                  | 8,122                     | 8%                      |
| Dracut                           | 50,000                    | 46%                     |
| Long-line                        | 21,596                    | 20%                     |
| Storage                          | 28,115                    | 26%                     |
| <b>Total Firm Transportation</b> | <b>107,833</b>            | <b>100%</b>             |

As illustrated by Table 4, the combined long-line and storage resources provide 46% of the total firm pipeline capacity, while the transportation contracts from Dracut also provide 46% of the pipeline capacity. The capacity contracts associated with Canadian supply contribute the smallest percentage (i.e., 8%) of the pipeline capacity.

**C. Supplemental Peaking Resources**

**Q. Please summarize the existing LNG and propane resources of the Company.**

A. EnergyNorth has three existing LNG facilities with a combined daily operational and storage capacity of 12,600 Dth. The maximum daily design vaporization capacity of the three LNG facilities is 22,800 Dth, which may be achieved if the Company refills the storage tanks using additional LNG truck loads (i.e., the storage capacity of 12,600 Dth is cycled). The propane facilities of the Company have a daily vaporization capability of 34,600 Dth with a storage volume of approximately 108,397 Dth. Table 5 below is a summary of the LNG and propane facilities by location.

**Table 5: EnergyNorth Supplemental Peaking Resources<sup>61</sup>**

| Location                        | LNG or Propane | Design Vaporization | Storage Capacity |
|---------------------------------|----------------|---------------------|------------------|
| Concord                         | LNG            | 4,800               | 4,200            |
| Manchester                      | LNG            | 8,400               | 4,200            |
| Tilton                          | LNG            | 9,600               | 4,200            |
| <b>Total LNG Facilities</b>     |                | <b>22,800</b>       | <b>12,600</b>    |
| Amherst                         | Propane        | n/a                 | 26,088           |
| Manchester                      | Propane        | 21,600              | 51,219           |
| Nashua                          | Propane        | 11,000              | 25,968           |
| Tilton                          | Propane        | 2,000               | 5,122            |
| <b>Total Propane Facilities</b> |                | <b>34,600</b>       | <b>108,397</b>   |

**Q. Please discuss the role of the LNG and propane facilities in meeting the Company's Design Day demand.**

**A.** EnergyNorth's existing LNG capacity is minimal. The combined daily operational vaporization capacity of the three existing LNG facilities is approximately 12,600 Dth, which represents only 8% of the Company's total Design Day resources as shown in Table 6 below.

**Table 6: EnergyNorth Design Day Resource Portfolio**

| Gas Supply                        | Contract MDQ (Dth/day) | % of Total Resources |
|-----------------------------------|------------------------|----------------------|
| Canadian Supply                   | 8,122                  | 5%                   |
| Dracut                            | 50,000                 | 32%                  |
| Long-line                         | 21,596                 | 14%                  |
| Storage                           | 28,115                 | 18%                  |
| <b>Total Firm Transportation</b>  | <b>107,833</b>         | <b>70%</b>           |
| LNG Daily Operational Capacity    | 12,600                 | 8%                   |
| Propane Daily Deliverability      | 34,600                 | 22%                  |
| <b>TOTAL DESIGN DAY RESOURCES</b> | <b>155,033</b>         | <b>100%</b>          |

<sup>61</sup> EnergyNorth's share of the Amherst storage capacity is 26,088 Dth, which represents 50% of the total storage capacity of 52,176 Dth.

1 Finally, the deliverability of the propane facilities is a large component of EnergyNorth's  
2 Design Day resources, representing approximately 22% of the total Design Day  
3 deliverability as shown in Table 6 above. As discussed in the Company's recent regulatory  
4 filings with the Commission (e.g., Docket Nos. DG 14-380 and DG 16-814), the  
5 EnergyNorth propane facilities have been in service for over 50 years, and the injection of  
6 propane into the Company's distribution system may cause issues with certain customers'  
7 high efficiency equipment.

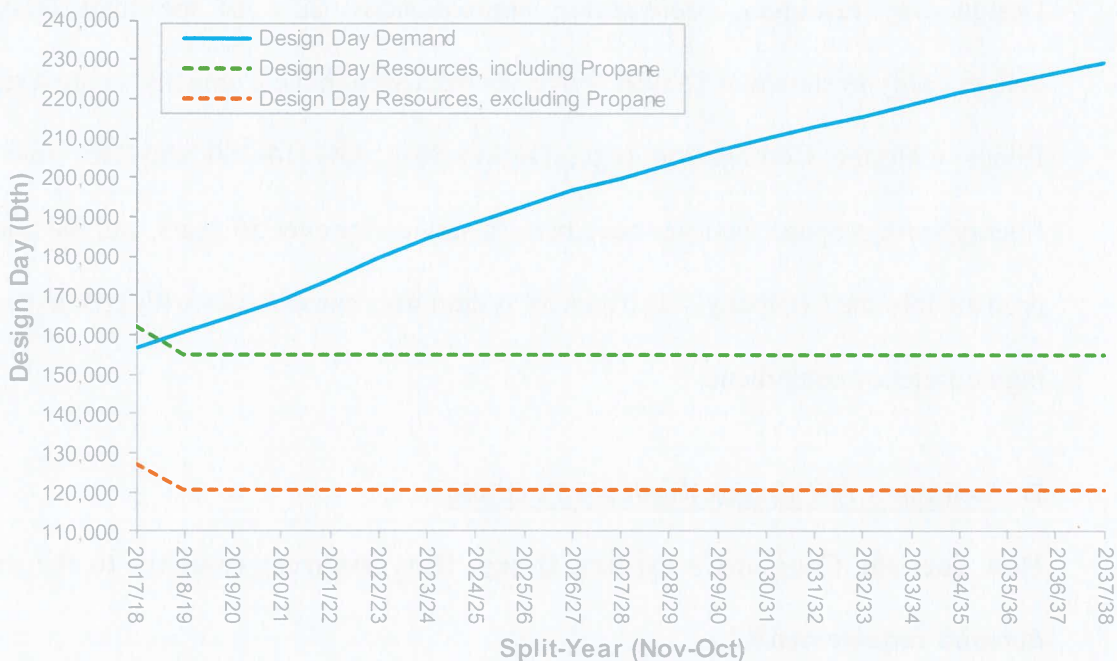
8 **D. Summary of Current Resource Portfolio**

9 **Q. How does the Company's existing Design Day resources compare to the projected**  
10 **demand requirements?**

11 A. As illustrated in Figure 25 and Table 7 below, the Company has a resource shortfall on  
12 Design Day beginning in 2018/19 of 5,956 Dth. Excluding the daily deliverability of the  
13 propane facilities of 34,600 Dth would increase the 2018/19 resource shortfall to 40,556  
14 Dth. By the 2037/38 split-year, the resource shortfall on Design Day is approximately  
15 75,000 Dth (or over 109,000 Dth excluding the propane facilities).

1

**Figure 25: EnergyNorth Design Day Demand and Resources<sup>62</sup>**



2

<sup>62</sup> As discussed previously, the 2017/18 Design Day resources include the contract with ENGIE for a combination liquid/vapor service for up to 7,000 Dth per day, which terminates on March 31, 2018.

1

**Table 7: EnergyNorth Design Day Resource Shortfall (Dth)<sup>63</sup>**

| Split-Year (Nov-Oct) | Design Day Demand | Design Day Resources, including Propane | Reserve / (Deficiency) including Propane | Reserve / (Deficiency) excluding Propane |
|----------------------|-------------------|---|--|--|
| 2017/18              | 156,822           | 162,033                                 | 5,211                                    | (29,389)                                 |
| 2018/19              | 160,989           | 155,033                                 | (5,956)                                  | (40,556)                                 |
| 2019/20              | 164,640           | 155,033                                 | (9,607)                                  | (44,207)                                 |
| 2020/21              | 168,934           | 155,033                                 | (13,901)                                 | (48,501)                                 |
| 2021/22              | 173,917           | 155,033                                 | (18,884)                                 | (53,484)                                 |
| 2022/23              | 179,382           | 155,033                                 | (24,349)                                 | (58,949)                                 |
| 2023/24              | 184,432           | 155,033                                 | (29,399)                                 | (63,999)                                 |
| 2024/25              | 188,856           | 155,033                                 | (33,823)                                 | (68,423)                                 |
| 2025/26              | 192,933           | 155,033                                 | (37,900)                                 | (72,500)                                 |
| 2026/27              | 196,785           | 155,033                                 | (41,752)                                 | (76,352)                                 |
| 2027/28              | 199,954           | 155,033                                 | (44,921)                                 | (79,521)                                 |
| 2028/29              | 203,491           | 155,033                                 | (48,458)                                 | (83,058)                                 |
| 2029/30              | 206,790           | 155,033                                 | (51,757)                                 | (86,357)                                 |
| 2030/31              | 210,016           | 155,033                                 | (54,983)                                 | (89,583)                                 |
| 2031/32              | 212,972           | 155,033                                 | (57,939)                                 | (92,539)                                 |
| 2032/33              | 215,843           | 155,033                                 | (60,810)                                 | (95,410)                                 |
| 2033/34              | 218,828           | 155,033                                 | (63,795)                                 | (98,395)                                 |
| 2034/35              | 221,631           | 155,033                                 | (66,598)                                 | (101,198)                                |
| 2035/36              | 224,148           | 155,033                                 | (69,115)                                 | (103,715)                                |
| 2036/37              | 226,863           | 155,033                                 | (71,830)                                 | (106,430)                                |
| 2037/38              | 229,590           | 155,033                                 | (74,557)                                 | (109,157)                                |

2

<sup>63</sup> As discussed previously, the 2017/18 Design Day resources include the contract with ENGIE for a combination liquid/vapor service for up to 7,000 Dth per day, which terminates on March 31, 2018.

1 **VI. ENERGYNORTH'S RESOURCE EVALUATION APPROACH**

2 **A. Portfolio Planning Objectives**

3 **Q. What are the overall objectives of EnergyNorth's resource portfolio planning**  
4 **process?**

5 A. The primary goal of the Company's resource planning process is to meet the expected  
6 demand requirements of its customers in a reliable manner at the best cost. The Company's  
7 resource plan maintains or enhances the reliability of the overall resource portfolio to meet  
8 the various forecasted planning scenarios. As market conditions continue to change and  
9 evolve, the Company's gas supply portfolio needs to have the flexibility and optionality to  
10 adapt to these new conditions while maintaining reliability. While the objectives of  
11 reliability, flexibility, diversity, and viability are paramount, it is important to achieve these  
12 objectives in a reasonable manner at the best cost.

13 **Q. Are EnergyNorth's resource planning objectives consistent with other LDCs?**

14 A. Yes. In our experience, EnergyNorth's gas supply portfolio objectives are consistent with  
15 the objectives of other LDCs.

16 **B. Evaluation of Resource Alternatives**

17 **1. Deliveries to City-gates**

18 **Q. Please discuss the resource options evaluated by EnergyNorth as part of its long-term**  
19 **resource planning process to meet the projected demand requirements.**

20 A. As part of EnergyNorth's evaluation of its long-term gas supply portfolio, the Company  
21 assessed not only the available gas supply options, but also the delivery options associated



1 with those supplies. Since certain gas supplies may rely on, or be enabled by, delivery  
2 options, EnergyNorth's evaluation of these delivery options is discussed first.

3 **Q. Please summarize the delivery options evaluated by the Company.**

4 A. EnergyNorth evaluated two pipeline delivery options that could provide incremental gas  
5 supplies to its service territory. The first option evaluated was an expansion of the existing  
6 pipeline connection between Tennessee and EnergyNorth (i.e., the TGP Concord Lateral).  
7 The second option analyzed was the construction of the Granite Bridge Pipeline that would  
8 connect the Joint Facilities to the TGP Concord Lateral.

9 **Q. Please describe the first option (i.e., the TGP Concord Lateral).**

10 A. As discussed previously in Section V, the TGP Concord Lateral is the primary and, for all  
11 intents and purposes, the only feed for the delivery of pipeline gas supplies to  
12 EnergyNorth's service territory. The TGP Concord Lateral runs from Dracut, along  
13 Interstate 93 terminating near Concord.

14 **Q. Is there available capacity on the TGP Concord Lateral?**

15 A. No, there is not. The TGP Concord Lateral, which was last expanded in 2009 when the  
16 Company contracted for 30,000 Dth per day of capacity, is fully subscribed.<sup>64</sup> Therefore,  
17 any additional requests to increase capacity and deliverability will, at a minimum, require  
18 incremental facilities on the Tennessee system.

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<sup>64</sup> The Commission issued an order approving the Settlement Agreement relating to the Company's transportation agreement on the TGP Concord Lateral expansion in Order No. 24,825 (Feb. 29, 2008). The TGP Concord Lateral expansion was approved for construction by the FERC in Docket No. CP 08-65-000.

1 **Q. Please describe the second delivery option (i.e., the Granite Bridge Pipeline).**

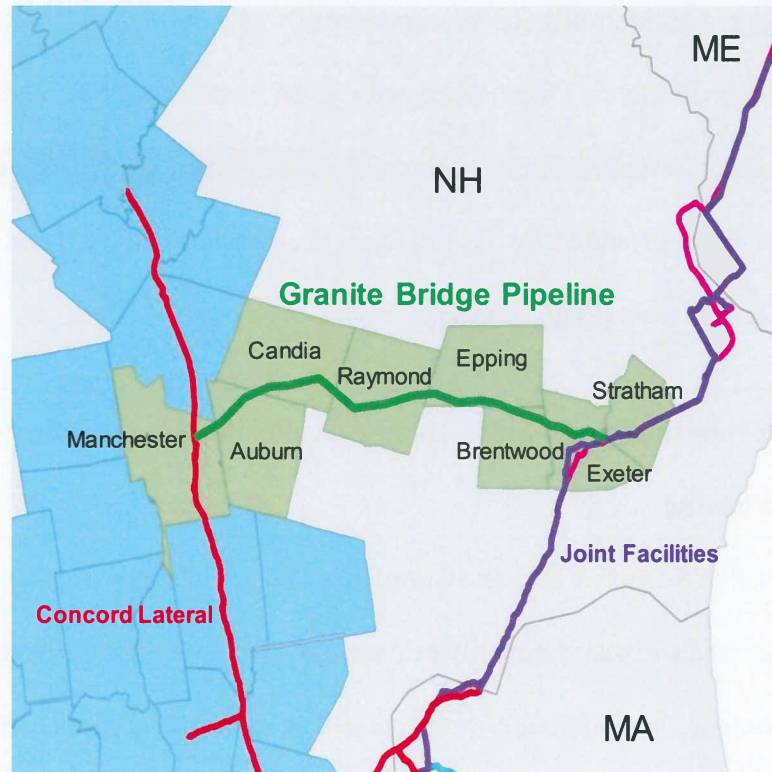
2 A. As discussed in the Fleck/DaFonte Testimony, the proposed Granite Bridge Pipeline would  
3 originate at the Joint Facilities in Stratham, and stay within the New Hampshire  
4 Department of Transportation (“NHDOT”) right-of-way along Route 101<sup>65</sup> to connect to  
5 the TGP Concord Lateral in Manchester. The Granite Bridge Pipeline would add a second  
6 pipeline feed to EnergyNorth’s existing service territory, and would enable upstream  
7 supplies on PNGTS and MNE-US to be delivered to the TGP Concord Lateral. In addition,  
8 re-gasified LNG from the proposed Granite Bridge LNG facility would connect to the  
9 Granite Bridge Pipeline for ultimate delivery to EnergyNorth. Figure 26 below is an  
10 illustrative map of the proposed Granite Bridge Pipeline.

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<sup>65</sup> In 2016, the New Hampshire Legislature passed a law (i.e., House Bill 626-FN-A) designating Route 101 as one of the state’s Energy Infrastructure Corridors.

1

**Figure 26: Illustrative Granite Bridge Pipeline Map<sup>66</sup>**



2

3 **Q. Did the Company conduct a quantitative and qualitative comparison of the two**  
4 **delivery options?**

5 A. Yes, the Company developed both a quantitative (i.e., cost comparison) and a qualitative  
6 (i.e., other benefits) assessment of the two delivery options.

7 **Q. Please summarize the cost for the first delivery option (i.e., an expansion of the TGP**  
8 **Concord Lateral).**

9 A. In its evaluation of potential gas supply options, EnergyNorth had discussions with  
10 Tennessee regarding an expansion of the existing facilities on the Tennessee system.

<sup>66</sup> Source: S&P Global Market Intelligence [modified by ScottMadden and EnergyNorth].

1 Pursuant to those confidential discussions, the Company received an estimate of the capital  
2 costs and indicative rates for an expansion of approximately 75,000 Dth per day on the  
3 TGP Concord Lateral. These estimated capital costs and associated indicative daily rates  
4 were based on certain delivery assumptions [REDACTED]

5 The daily rates provided by Tennessee to EnergyNorth for expanding the TGP Concord  
6 Lateral ranged from [REDACTED] to [REDACTED] per Dth.

7 **Q. Please review the Company's cost analysis for the second delivery option, the Granite**  
8 **Bridge Pipeline.**

9 A. As detailed in Section VII.C, the Company used a multi-step process to develop a levelized  
10 cost of service and resulting daily rate estimate for the Granite Bridge Pipeline. The results  
11 of the Company's modeling effort produced an estimated daily rate of approximately \$0.47  
12 per Dth based on the estimated levelized annual cost of \$12.75 million and capacity of  
13 75,000 Dth per day for the Granite Bridge Pipeline. The daily rate for the Granite Bridge  
14 Pipeline was estimated based on a capacity of 75,000 Dth per day to provide an "apples-  
15 to-apple" unit cost comparison to the expansion of the TGP Concord Lateral. If the daily  
16 rate of the Granite Bridge Pipeline was estimated based on the operating capacity of  
17 approximately 150,000 Dth per day, the resulting unit cost would be cut in half. Please see  
18 the direct testimony of Timothy S. Lyons for a more detailed discussion of the levelized  
19 cost of service model and Granite Bridge Pipeline unit cost estimate.

1 **Q. Please discuss the results of the Company's cost analysis of the two delivery options.**

2 A. The estimated daily rate associated with the Granite Bridge Pipeline is significantly lower  
3 than the estimated daily rate for an expansion of the TGP Concord Lateral. The estimated  
4 daily rate to expand the TGP Concord Lateral ranged from [REDACTED] to [REDACTED] per Dth, whereas  
5 the estimated daily rate for constructing the Granite Bridge Pipeline was approximately  
6 \$0.47 per Dth, which is approximately [REDACTED] and [REDACTED] lower than the low and high end of  
7 the daily rate for the expansion of the TGP Concord Lateral, respectively. Stated  
8 differently, the cost to construct the Granite Bridge Pipeline could increase by over [REDACTED]  
9 [REDACTED] and the resulting rate would still be lower than the low end of the estimated daily rate  
10 to expand the TGP Concord Lateral.

11 **Q. Please discuss your observations with respect to the Company's cost analysis for the**  
12 **two delivery options.**

13 A. The methodologies used to develop the quantitative analysis for the two delivery options  
14 were reasonable and allowed the Company to review the options on a comparable basis, as  
15 each option had a daily rate for service that reflected a similar volume of delivery. With  
16 respect to the first delivery option (i.e., an expansion of the TGP Concord Lateral), the  
17 Company relied on the owner and operator of the Tennessee system to provide the  
18 estimated capital requirement and associated daily rate for the expansion project. The  
19 owner and operator of existing pipeline infrastructure is generally best positioned to  
20 provide an estimate of the capital costs and expected daily rate associated with an  
21 expansion of that infrastructure. Therefore, the Company's reliance on the capital cost and

1 daily rate information from Tennessee regarding an expansion of the TGP Concord Lateral  
2 is appropriate and reasonable.

3 Regarding the second physical delivery option (i.e., the Granite Bridge Pipeline), the  
4 Company developed a levelized cost of service model to estimate the daily rate for the  
5 Granite Bridge Pipeline, which allowed the Company to compare it to the estimated daily  
6 rate for an expansion of the TGP Concord Lateral on an apples-to-apples basis. The  
7 levelized cost of service model included an estimate of the initial capital cost of the project  
8 supported by a conceptual engineering design provided by CHA Consulting, Inc. (“CHA”),  
9 which included detailed mapping of the proposed route and reflected several discussions  
10 with the NHDOT. In addition, the levelized cost of service model included estimates for  
11 various financial and operational assumptions or costs, which were developed by the  
12 Company. This detailed modeling approach to develop a daily rate for the Granite Bridge  
13 Pipeline is appropriate and reasonable.

14 **Q. Did EnergyNorth consider the qualitative benefits provided by the Granite Bridge**  
15 **Pipeline?**

16 A. Yes. The Company evaluated various qualitative benefits, including reliability, flexibility,  
17 diversity, and viability of the Granite Bridge Pipeline.

18 **Q. Please review the qualitative benefits associated with the Granite Bridge Pipeline.**

19 A. There are five primary qualitative benefits associated with the Granite Bridge Pipeline:

- 1           • First, an additional pipeline feed to the Company (i.e., the Granite Bridge Pipeline)  
2           increases the diversity of EnergyNorth’s delivery infrastructure, which  
3           significantly increases the reliability and security of gas supply deliveries.
- 4           • Second, a new delivery connection increases delivery options as the Company  
5           could access natural gas supplies that are delivered or pathed on the Granite Bridge  
6           Pipeline, the TGP Concord Lateral, the proposed Granite Bridge LNG facility, or  
7           directly to the city-gates. This increase in gas supply diversity and options increases  
8           the reliability of the overall gas supply portfolio and provides more price stability  
9           for the customers of EnergyNorth.
- 10          • Third, the Granite Bridge Pipeline would provide pressure support to the TGP  
11          Concord Lateral as the Granite Bridge Pipeline will connect with the Tennessee  
12          system in Manchester, with the capability to deliver 750 pounds per square inch  
13          (“psi”) into the TGP Concord Lateral, where pressures at times have dropped to  
14          300 psi or less during the winter.
- 15          • Fourth, the Granite Bridge Pipeline would provide the Company with negotiation  
16          leverage. As discussed in Section V.B above, the Company’s current resource  
17          portfolio has two Tennessee contracts that originate at Dracut and have a total MDQ  
18          of 50,000 Dth per day, which is nearly 50% of the Company’s total pipeline  
19          capacity. When these two Tennessee contracts come up for renewal, the Granite  
20          Bridge Pipeline could provide a replacement option for EnergyNorth, thus  
21          providing leverage in the negotiation with Tennessee regarding these contracts.

- 1           • Finally, the Granite Bridge Pipeline would allow the Company the opportunity to  
2           provide natural gas as a fuel choice to communities along the construction path of  
3           the pipeline; specifically, the towns of Epping, Raymond, and Candia. As such,  
4           towns, businesses, and homes that currently do not have access to natural gas, given  
5           the absence of gas infrastructure, would now have choices with respect to their  
6           energy decisions.

7   **Q.    Please explain in detail the increase in diversity and reliability associated with the**  
8   **Granite Bridge Pipeline.**

9   A.    Although both delivery options (i.e., the Granite Bridge Pipeline and an expansion of the  
10   TGP Concord Lateral) increase the reliability of gas supply deliveries and reduce the  
11   reliance on the Company's aging propane facilities to meet Design Day and extreme cold  
12   weather demand, the Granite Bridge Pipeline significantly diversifies the physical  
13   infrastructure associated with supplying the Company and, importantly, provides  
14   additional pressure support to the existing TGP Concord Lateral, thus providing a higher  
15   level of reliability than an expansion of the TGP Concord Lateral. The Granite Bridge  
16   Pipeline will be connected on its east end to the Joint Facilities, which has a maximum  
17   allowable operating pressure ("MAOP") of 1,440 psi, as compared to Tennessee's MAOP  
18   of 750 psi. More importantly, Tennessee is only obligated to provide a minimum of 100  
19   psi on the TGP Concord Lateral. Given the higher inlet pressure from the Joint Facilities,  
20   the Granite Bridge Pipeline will help bolster the TGP Concord Lateral pressures to the  
21   south and north during peak winter periods, which would significantly enhance the  
22   reliability of gas supply deliveries to the Company.



1 Further, EnergyNorth would no longer depend on one feed or line (i.e., the TGP Concord  
2 Lateral) for almost all of its pipeline supplies, and would now have access to the proposed  
3 Granite Bridge LNG facility and supplies on the Joint Facilities, enhancing the diversity  
4 and flexibility of supplies. Simply stated, a second feed would: (i) provide the Company  
5 with an alternative means of delivering gas supplies should the other line experience  
6 service disruption; and (ii) bolster the TGP Concord Lateral pressures in general. This  
7 increase in physical delivery reliability and supply security is achieved only with a second  
8 line and not with an expansion of the TGP Concord Lateral.

## 9 2. Upstream Gas Supplies

10 **Q. Once EnergyNorth identified the Granite Bridge Pipeline as the preferred delivery**  
11 **option, what was the next step in the Company's analysis?**

12 A. After establishing the Granite Bridge Pipeline as the preferred delivery option, the  
13 Company next focused on the evaluation of specific natural gas supply options within the  
14 context of the overall resource portfolio. The options evaluated for upstream gas supply  
15 covered a variety of supply and volume options, including: (1) pipeline supplies (e.g.,  
16 PNGTS); (2) imported LNG (e.g., Repsol and ENGIE); and (3) on-system assets.

17 **Q. Please describe the process used by the Company to analyze the gas supply options.**

18 A. EnergyNorth utilized the following framework to evaluate the natural gas supply options.  
19 First, the Company identified gas supply options that were available in the marketplace or  
20 have certain development activity underway. Next, EnergyNorth determined which gas  
21 supply options should be considered for further quantitative analysis, modeled using the

1 SENDOUT® portfolio optimization software, and qualitative analysis (i.e., other benefits  
2 such as portfolio diversity). Stated differently, the Company identified the supply options  
3 that were viable for further analysis. Finally, based on the totality of the analysis,  
4 EnergyNorth identified the appropriate volumes and contract terms for certain gas supply  
5 options.

6 **Q. Prior to discussing the Company's gas supply evaluation process, please describe the**  
7 **SENDOUT® model.**

8 A. The SENDOUT® model is a proprietary linear programming model owned by ABB  
9 (formerly, Ventyx) and used by EnergyNorth since 1996 to: (1) determine the adequacy of  
10 the Company's existing and potential gas supply portfolio in meeting projected  
11 requirements; and (2) identify any supply or volume shortfalls during the analysis period.  
12 The results of the SENDOUT® model provide the Company with the least-cost, economic  
13 dispatch of its existing resources subject to the underlying assumptions (e.g., contractual  
14 and operating constraints), and assist with identifying the need for, and type of, additional  
15 resources required during the analysis period. The SENDOUT® model calculates the  
16 optimal portfolio based on certain Company-specific assumptions including, daily demand,  
17 weather patterns, pipeline and storage contract volumes, rates, and costs, gas supply prices  
18 for various indices, and contractual paths for the various supplies. Based on these operating  
19 and market assumptions, the SENDOUT® model can be used to determine the best use of  
20 a given portfolio of supply, capacity, and storage contracts to meet a specified demand.  
21 Please note that the SENDOUT® model dispatches the portfolio based on the resources

1 with the lowest variable cost over the duration of the modeling period to meet demand  
2 since the demand charges are fixed and, therefore, unavoidable.

3 EnergyNorth has used the SENDOUT® model in several recent regulatory filings with the  
4 Commission, including the Company's cost of gas submissions, the NED Market and  
5 Supply Path filings, and IRP filings. For this proceeding, EnergyNorth also used the  
6 Resource Mix module of the SENDOUT® model, in which the appropriate mix of  
7 incremental resources and associated volumes or contract sizes are determined and  
8 optimized within the SENDOUT® model itself. Stated differently, the Resource Mix  
9 module allows the Company to input various gas supply resource options that the  
10 SENDOUT® model can include or exclude to determine the optimal portfolio. As such,  
11 the Company does not need to define scenarios that include certain resources and exclude  
12 others. Rather, the Resource Mix module of the SENDOUT® model will select the  
13 resource and the associated volume from the available options that achieves the optimal  
14 solution. To do this, the SENDOUT® model analyzes the available contracts and the size  
15 of each contract (e.g., MDQ) to determine the combination of resources that results in the  
16 lowest total cost over the duration of the modeling period, considering both variable and  
17 fixed costs.

18 **Q. Please discuss the first step in the Company's analysis framework (i.e., identifying gas**  
19 **supply options).**

20 **A.** The first step in the EnergyNorth framework was to identify the range of likely or viable  
21 natural gas supply resources that are currently under development, being marketed to the

1 Company, or have been identified as a potential supply option. The list of gas supply  
2 resource options was broad and based on the market insight and knowledge of the  
3 EnergyNorth Energy Procurement Group, who are active in industry organizations and  
4 trade groups as well as participants at energy conferences, pipeline customer groups, and  
5 regulatory proceedings. Based on the knowledge of the EnergyNorth personnel, the  
6 following gas supply resource options were identified:

- 7 • Pipeline transportation capacity from the Dawn Hub on the Union Gas, TCPL  
8 Canadian Mainline, and PNGTS pipeline systems;<sup>67</sup>
- 9 • Pipeline transportation capacity on Tennessee (i.e., service on the Tennessee  
10 Mainline from receipt points upstream of Dracut);
- 11 • Pipeline transportation capacity on Algonquin (i.e., Enbridge expansion of the  
12 Algonquin and MNE pipeline systems);
- 13 • Imported LNG supplies from Repsol;
- 14 • Imported LNG supplies from ENGIE delivered to the EnergyNorth city-gates; and
- 15 • An on-system LNG facility (i.e., the Granite Bridge LNG facility).

16 **Q. Please review the gas supply options that were considered for further evaluation.**

17 **A.** After reviewing the various gas supply alternatives, the following options were short-listed  
18 as viable options and considered for further evaluation:

---

<sup>67</sup> As discussed in Section VII.B, the Union Gas capacity is a component of the TCPL Canadian Mainline via a TBO.

- 1           • Pipeline transportation capacity from the Dawn Hub on the TCPL Canadian
- 2           Mainline and PNGTS pipeline systems;
- 3           • Imported LNG supplies from Repsol;
- 4           • Imported LNG supplies from ENGIE delivered to the EnergyNorth city-gates; and
- 5           • An on-system LNG facility (i.e., the Granite Bridge LNG facility).

6           These supply alternatives cover a wide breadth of gas supply options, including pipeline  
7           capacity, winter season services, and peaking supplies.

8   **Q.   Why were the pipeline transportation capacity paths on the Tennessee Mainline and**  
9   **Algonquin excluded from the short-listed options?**

10  A.   The Tennessee Mainline path was not included as a short-listed option for two primary  
11  reasons. First, the Tennessee Mainline is fully subscribed for capacity from west-to-east  
12  (e.g., from Wright, New York to Dracut, Massachusetts or EnergyNorth city-gates).  
13  Incremental capacity on the Tennessee Mainline associated with volumes originating at  
14  Wright or other points west of Dracut, would require incremental facilities on the  
15  Tennessee Mainline, which would be costly as evidenced by the estimated daily rate to  
16  expand the TGP Concord Lateral discussed above, or would require a greenfield expansion,  
17  such as the canceled TGP NED project.

18           Second, the PNGTS path provides access to the Dawn Hub, which is one of the more liquid  
19  natural gas trading points in North America, while the Tennessee Mainline path would  
20  originate at points west of Dracut, Massachusetts, such as Wright, New York. Although

1 the Wright point may become more liquid if incremental gas pipeline capacity is  
2 constructed to Wright, it is considered a less liquid point today especially when compared  
3 to the Dawn Hub. As a result, the PNGTS path was the preferred pipeline option relative  
4 to a Tennessee Mainline option.

5 Finally, with respect to the Algonquin path, EnergyNorth did not identify an active  
6 Enbridge project on Algonquin and/or MNE to evaluate. As discussed in Section III.B,  
7 Algonquin has withdrawn its Access Northeast project from the pre-filing review process  
8 at the FERC and no other Enbridge sponsored project was identified by the Company for  
9 evaluation.

10 **Q. Prior to discussing why EnergyNorth included an on-system LNG facility as a short-**  
11 **listed supply option, please describe the proposed Granite Bridge LNG facility.**

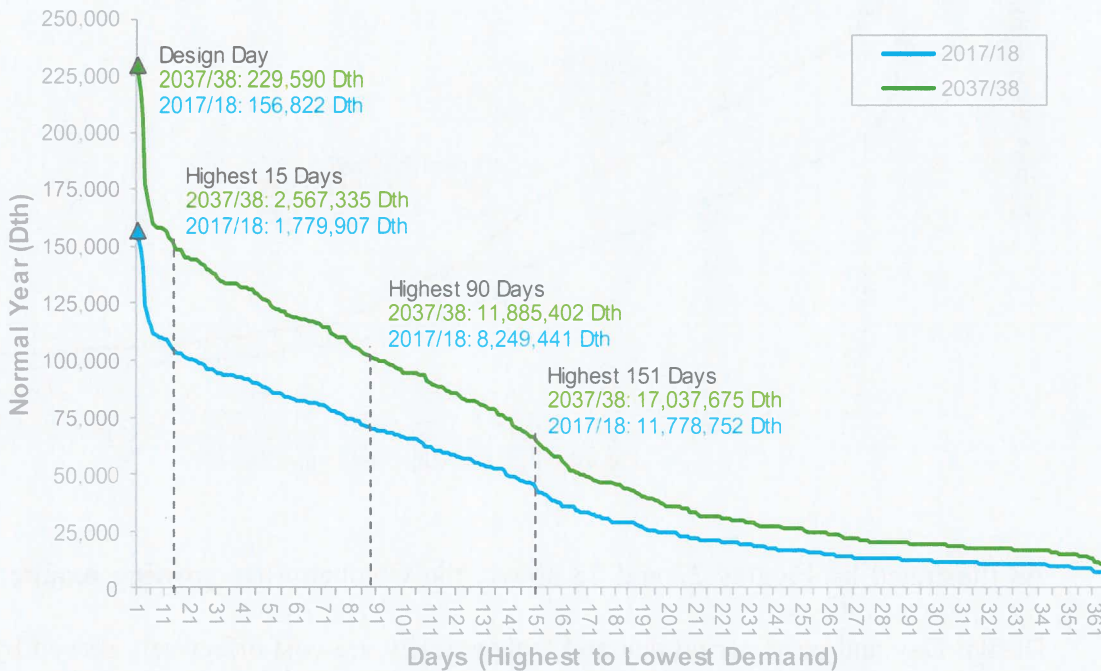
12 A. As detailed in the Fleck/DaFonte Testimony, EnergyNorth is proposing to construct an on-  
13 system LNG facility, the Granite Bridge LNG facility, which would connect to the  
14 proposed Granite Bridge Pipeline. The Granite Bridge LNG facility would consist of 2 Bcf  
15 of storage capacity, 150,000 Mcf per day of vaporization, and 8,000 Mcf per day of  
16 liquefaction.

17 **Q. Please discuss the inclusion of an on-system LNG facility as a short-listed option.**

18 A. The Company used two distinct analyses to conclude that an on-system LNG facility  
19 should be evaluated as part of the quantitative analysis (i.e., the SENDOUT® modeling).  
20 First, as discussed previously in Section IV.B, the Company developed a load duration

1 curve analysis to review the projected demand requirements as shown in Figures 27 and 28  
2 below.

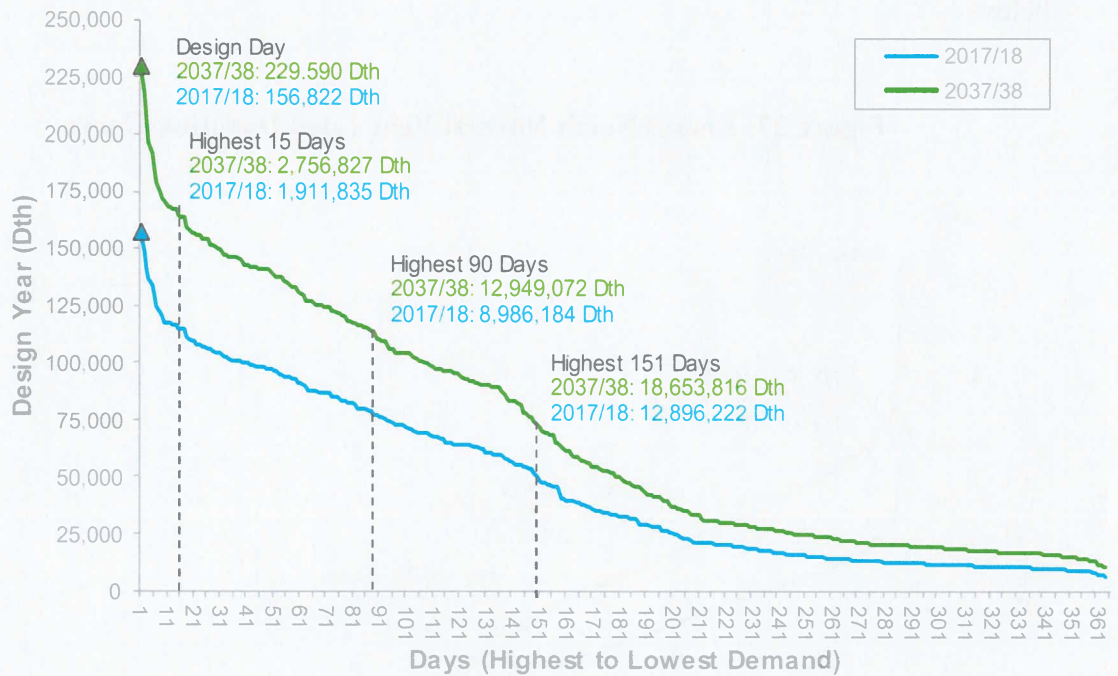
3 **Figure 27: EnergyNorth Normal Year Load Duration Curve**



4

1

**Figure 28: EnergyNorth Design Year Load Duration Curve**



2

3

As illustrated by Figures 27 and 28 above, the Company has growing requirements in Design Day and peak period demand that typically are cost effectively served by a peak supply resource such as on-system LNG. Therefore, including an on-system LNG facility (i.e., the Granite Bridge LNG facility) as an option for consideration in the resource portfolio was reasonable and appropriate.

8

The second analysis undertaken by the Company regarding on-system LNG was to compare or benchmark the role of on-system LNG in the existing EnergyNorth portfolio relative to the level of on-system LNG in the supply portfolios of other LDCs in New England. Given the similarities in demand requirements (i.e., heating sensitive customers) and, therefore, winter demand requirements of New England LDCs, the LNG

12



1 benchmarking analysis offers a good comparison of the role of on-system LNG in the  
2 various LDC portfolios. For the first benchmarking metric, the Company compared on-  
3 system LNG vaporization relative to expected Design Day demand and, for the second  
4 benchmarking metric, the Company compared LNG storage relative to LNG vaporization  
5 (i.e., days of LNG storage). The following table summarizes the results of the LNG  
6 benchmarking analysis.

7 **Table 8: Summary of LNG Benchmarking Analysis<sup>68</sup>**

| LDC   | LNG Storage Capacity (MMBtu) | LNG Vaporization (MMBtu) | Design Day Demand (MMBtu) | % LNG Vaporization of Design Day | Days of LNG Storage |
|---|------------------------------|--------------------------|---------------------------|----------------------------------|---------------------|
| Berkshire Gas Company                                 | 12,260                       | 3,300                    | 64,705                    | 5%                               | 3.7                 |
| Columbia Gas of Massachusetts (Bay State Gas Company) | 1,810,004                    | 112,500                  | 502,152                   | 22%                              | 16.1                |
| Eversource Energy (NSTAR Gas)                         | 3,650,000                    | 210,000                  | 517,000                   | 41%                              | 17.4                |
| Eversource Energy (Yankee Gas Services Company)       | 1,200,000                    | 105,000                  | 465,411                   | 23%                              | 11.4                |
| Liberty Utilities (New England Gas Company)           | 164,000                      | 18,500                   | 77,260                    | 24%                              | 8.9                 |
| National Grid (Boston Gas/Colonial Gas)               | 4,934,319                    | 507,641                  | 1,403,000                 | 36%                              | 9.7                 |
| National Grid (Narragansett Electric Company)         | 802,000                      | 113,000                  | 354,000                   | 32%                              | 7.1                 |
| UIL (Connecticut Natural Gas Corporation)             | 1,200,000                    | 97,500                   | 347,137                   | 28%                              | 12.3                |
| UIL (Southern Connecticut Gas Company)                | 1,200,000                    | 82,500                   | 318,950                   | 26%                              | 14.5                |
| Unitil (Fitchburg Gas & Electric)                     | 4,326                        | 3,172                    | 22,198                    | 14%                              | 1.4                 |
| Unitil (Northern Utilities)                           | 13,335                       | 10,000                   | 162,759                   | 6%                               | 1.3                 |
| Total   | 14,990,244                   | 1,263,113                | 4,234,572                 | 30%                              | 9.4                 |

8  
9 With respect to the first benchmarking metric (LNG vaporization relative to Design Day  
10 demand), the existing LNG vaporization for EnergyNorth represents about 8% of the  
11 Design Day demand.<sup>69</sup> Conversely, for the comparison group, the ratio of on-system LNG  
12 vaporization capability compared to Design Day demand averaged 30%, with Eversource  
13 Energy (NSTAR Gas) having the highest LNG vaporization to Design Day demand ratio  
14 at 41%. Regarding the second benchmarking metric (days of LNG storage), the Company

<sup>68</sup> Please note, the Design Day demand represents the projected demand for 2017/18. Sources: most recently filed Integrated Resource Plan for each respective LDC.

<sup>69</sup> Please note, EnergyNorth's vaporization capacity is limited by the storage capacity.

1 has less than one day of storage, while the comparator group average is almost 10 days of  
2 LNG storage, with several LDCs having 12 to 16 days of LNG storage.

3 As shown by the above table and analysis, the Company does not have the LNG  
4 vaporization relative to Design Day demand as its peer group, nor does EnergyNorth have  
5 the days of LNG storage that is typical of New England LDCs. Therefore, including on-  
6 system LNG (i.e., the Granite Bridge LNG facility) as a resource option for further  
7 evaluation was reasonable and appropriate.

8 **Q. Once the short-listed resource options were identified, how did the Company organize**  
9 **its SENDOUT® modeling?**

10 A. The Company's SENDOUT® modeling was organized into two resource planning  
11 scenarios, which centered on the resources available to serve the projected Design Day and  
12 peak period demands (i.e., including or excluding the Granite Bridge LNG facility, and  
13 whether the existing propane facilities are retired). Specifically, the two resource planning  
14 scenarios used by EnergyNorth are summarized below:

- 15 • Base Case: includes the Granite Bridge LNG facility, and assumes the existing  
16 propane facilities are retired;
  - 17 ○ Base Case Sensitivity: includes the Granite Bridge LNG facility, and  
18 assumes the existing propane facilities remain in service;
- 19 • Alternative Case: excludes the Granite Bridge LNG facility, and assumes the  
20 existing propane facilities are retired; and

- 1                   ○ Alternative Case Sensitivity: excludes the Granite Bridge LNG facility, and  
2                   assumes the existing propane facilities remain in service.

3                   In addition, given the lead time required for infrastructure developments and the long-term  
4                   nature of pipeline capacity contracts, EnergyNorth performed cost simulations using the  
5                   SENDOUT® model for the 21-year period from November 1, 2017, through October 31,  
6                   2038, for each resource planning scenario.

7                   **Q. Please briefly review the SENDOUT® modeling assumptions that are common across**  
8                   **the four resource planning scenarios.**

9                   A. The Company used the following key assumptions in the SENDOUT® modeling  
10                  regardless of the resource planning scenario:

- 11                  • All legacy contracts for pipeline capacity and storage service expiring during the  
12                  forecast period would be renewed for the length of the analysis with no change in  
13                  rates, quantities, or operating characteristics.
- 14                  • The existing LNG facilities remain in service for the duration of the analysis and,  
15                  as needed, liquid-only supply is available to refill the LNG storage inventory.
- 16                  • The natural gas prices are based on monthly closing prices on August 18, 2017,  
17                  from S&P Global Market Intelligence. The Company used the natural gas prices  
18                  for the length of the time period provided by S&P Global Market Intelligence and,  
19                  for the remaining years in the analysis, the natural gas prices are escalated at 1%.

- 1           • Gas supplies are available at Dracut, with the winter price for those supplies  
2           reflective of the daily weather pattern (i.e., colder weather days will have higher  
3           daily prices at the Dracut point), and the summer price for those supplies are based  
4           on monthly closing prices on August 18, 2017, from S&P Global Market  
5           Intelligence.

6   **Q.   How were the gas supply resource options analyzed by the Company in SENDOUT®?**

7   **A.   First, EnergyNorth included the following resources in each resource planning scenario:**

- 8           • The capacity contract with ENGIE for 90-day winter, combination (i.e., liquid  
9           and/or vapor) service with an MDQ of 7,000 Dth per day was included through  
10          March 31, 2022.
- 11          • Pipeline transportation capacity from the Dawn Hub on the TCPL Canadian  
12          Mainline and PNGTS pipeline systems was phased-in over three-years, with an  
13          MDQ of 1,784 Dth per day starting on November 1, 2018, 4,432 Dth per day  
14          starting on November 1, 2019, and 5,000 Dth per day starting on November 1, 2020.
- 15          • The Granite Bridge Pipeline was placed in service on November 1, 2021, and there  
16          was no expansion of the TGP Concord Lateral.

17          Then the Company outlined the following gas supply options for the Resource Mix module:

- 18          • Repsol delivered service with an MDQ of up to 150,000 Dth per day and a seasonal  
19          maximum capacity of 6,000,000 Dth, beginning on November 1, 2021, through the  
20          end of the forecast horizon.

- 1 • Pipeline transportation capacity from the Dawn Hub on the TCPL Canadian  
2 Mainline and PNGTS pipeline systems with an MDQ of up to 150,000 Dth per day  
3 beginning on November 1, 2021, through the end of the forecast horizon.
- 4 • ENGIE 90-day winter, combination service with an MDQ of up to 7,000 Dth per  
5 day beginning on November 1, 2022, through the end of the forecast horizon.

6 As discussed above, the Resource Mix module of the SENDOUT® model selects the  
7 resource and the associated volume from the available options that achieves the optimal  
8 solution (i.e., lowest total cost over the duration of the forecast period, considering both  
9 variable and fixed costs) to meet the projected demand requirements.

10 **Q. Please summarize the results of the SENDOUT® model runs.**

11 A. The SENDOUT® results for the Base and Alternative Cases are summarized in Table 9  
12 below and the detailed SENDOUT® reports are provided as Exhibits WRK/JMS-4 through  
13 WRK/JMS-7.

14 **Table 9: EnergyNorth SENDOUT® Model Runs**

| Resource Planning Scenario   | Exhibit No. | Granite Bridge LNG | Propane Facilities | Resource Mix Results |                  |                 | Total System Cost (\$000) | Comparison to Base Case (\$000) |
|------------------------------|-------------|--------------------|--------------------|----------------------|------------------|-----------------|---------------------------|---------------------------------|
|                              |             |                    |                    | Dawn (Dth/day)       | Repsol (Dth/day) | ENGIE (Dth/day) |                           |                                 |
| Base Case                    | WRK/JMS-4   | 2.0 Bcf            | No                 | 9,470                | 0                | 0               | \$2,797,138               | \$ -                            |
| Base Case Sensitivity        | WRK/JMS-5   | 2.0 Bcf            | Yes                | 9,260                | 0                | 0               | \$2,797,226               | \$ 88                           |
| Alternative Case             | WRK/JMS-6   | No                 | No                 | 6,840                | 105,360          | 1,150           | \$2,976,108               | \$ 178,970                      |
| Alternative Case Sensitivity | WRK/JMS-7   | No                 | Yes                | 19,230               | 51,210           | 7,000           | \$2,800,530               | \$ 3,392                        |

16 As shown in Table 9, under the Base Case resource planning scenario (which includes the  
17 Granite Bridge LNG facility and assumes retirement of the existing propane facilities), the  
18 Company would develop and construct the Granite Bridge LNG facility, which is expected

1 to commence service on April 1, 2022, and would phase out the use of the existing propane  
2 facilities depending on the timing of the in-service date of the Granite Bridge LNG facility.  
3 In addition, the Resource Mix module results included capacity on the Dawn to PNGTS  
4 path of approximately 9,470 Dth per day and zero Repsol and ENGIE capacity. The total  
5 cost of the Base Case portfolio was approximately \$2.797 billion over the analysis period,  
6 which was the lowest total cost of the four resource planning scenarios analyzed. Under  
7 the Base Case Sensitivity where the propane facilities remain in-service, the Resource Mix  
8 module results were essentially unchanged and the total portfolio cost was equivalent (i.e.,  
9 approximately \$2.797 billion). In other words, the inclusion of the Granite Bridge LNG  
10 facility provides the Company a low to no cost option with respect to including or retiring  
11 the aging propane facilities.

12 The Alternative Case resource planning scenario (which excludes the Granite Bridge LNG  
13 facility and assumes the retirement of the existing propane facilities) results in a total  
14 portfolio cost of \$2.976 billion over the analysis period, which is nearly \$180 million more  
15 than the Base Case scenario. Under the Alternative Case, the results of the Resource Mix  
16 module included a volume of approximately 6,840 Dth per day on the Dawn to TCPL  
17 Canadian Mainline to PNGTS path, a volume of over 105,000 Dth per day from Repsol,  
18 and 1,150 Dth per day of ENGIE supply. Under the Alternative Case Sensitivity (which  
19 excludes the Granite Bridge LNG facility and the propane facilities remain in service), the  
20 results of the Resource Mix module included a volume of approximately 19,230 Dth per  
21 day on the Dawn to TCPL Canadian Mainline to PNGTS path, a volume of approximately  
22 51,000 Dth per day from Repsol, and 7,000 Dth per day of ENGIE supply. The cost

1 associated with the Alternative Case Sensitivity was approximately \$2.801 billion over the  
2 analysis period, which is approximately \$3 million more than the Base Case and Base Case  
3 Sensitivity scenarios.

4 **Q. Please review the cost implications for retiring the Company's propane facilities in**  
5 **the Base Case and Alternative Case.**

6 A. In the Base Case, the decision to retire the propane facilities would result in a cost decrease  
7 of approximately \$88,000. In other words, in the Base Case, the inclusion or retirement of  
8 the propane facilities is a "no cost" option as the Granite Bridge LNG facility provides the  
9 Company with significant flexibility. In the Alternative Case, the cost to retire the propane  
10 facilities is equal to approximately \$176 million, as the Company does not have the  
11 flexibility and daily capability of the Granite Bridge LNG facility. It is interesting to note  
12 that the cost to retire the propane facilities in the Alternative Case is nearly as much as the  
13 estimated capital cost of the Granite Bridge LNG facility of approximately \$201.7 million,  
14 which is discussed in Section VII.C below.

15 **Q. Based on the results of the SENDOUT® analysis, did the Company further evaluate**  
16 **the natural gas supply from Repsol?**

17 A. Yes, EnergyNorth was engaged in discussions with Repsol for winter peaking supply.  
18 However, the Company determined that the Repsol supply was not a viable long-term  
19 option for three reasons. First, the Resource Mix results for the Base Case resource  
20 planning scenarios indicated that the Repsol supply was not cost-effective compared to the  
21 alternative resource options. Second, the full MDQ of the Repsol service would commence

1 on November 1, 2018, and, thus, would not provide EnergyNorth with incremental supply  
2 to meet its Design Day and peak season needs until the Granite Bridge Pipeline was placed  
3 into service. Third, the proposed contract terms would not provide the Company and its  
4 customers with [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]

11 [REDACTED]

12 **Q. Did EnergyNorth consider the qualitative benefits provided by each of the preferred**  
13 **upstream gas supply options?**

14 A. Yes, the Company evaluated each of the supply resource options on a qualitative basis  
15 (e.g., reliability, flexibility, and diversity) and as part of the Company's overall gas supply  
16 portfolio.

17 **Q. What are the qualitative benefits associated with the ENGIE combination service**  
18 **contract?**

19 A. The ENGIE combination service contract provides two unique benefits that will increase  
20 the flexibility and reliability of EnergyNorth's resource portfolio in the near-term. First,  
21 the ENGIE supply is the only resource option that can be delivered, on a firm basis, to the



1 EnergyNorth city-gates. Therefore, it is the only pipeline-based option that can provide  
2 incremental supply in the near-term to meet the Company's growing Design Day demand.  
3 Secondly, EnergyNorth has the option to receive the ENGIE volume as vapor or liquid.  
4 The ENGIE supply can be delivered as vapor to the Company's city-gate stations, as liquid  
5 via trucks to refill the Company's on-system LNG facilities, or as a combination of vapor  
6 and liquid. This option to receive the product as vapor or liquid enhances the reliability of  
7 the EnergyNorth portfolio and provides the Company with increased flexibility to meet  
8 various demand scenarios. In addition to these two unique benefits, the ENGIE price  
9 structure provides more cost stability to the EnergyNorth portfolio as the price is based on  
10 [REDACTED]. This price structure benefits the Company and its  
11 customers as [REDACTED]

12 [REDACTED]  
13 [REDACTED]  
14 **Q. What are the qualitative benefits of the TCPL/PNGTS transportation capacity?**

15 **A.** The TCPL/PNGTS capacity increases the reliability, flexibility, and supply diversity of the  
16 Company's resource portfolio by providing additional access to the Dawn Hub, which is  
17 one of the most liquid gas supply points in North America, with access to numerous  
18 suppliers and significant storage capacity. In addition, the TCPL/PNGTS capacity provides  
19 delivery flexibility. As currently structured, the Company's precedent agreement with  
20 PNGTS has Dracut as the primary delivery point for the capacity. Since Dracut is the  
21 interconnection point with Tennessee, EnergyNorth could use its existing capacity on  
22 Tennessee to transport the PNGTS supply to the Company's city-gates. However, it only

1 becomes an incremental supply resource once the Granite Bridge Pipeline is placed into  
2 service, at which time EnergyNorth will have the option to move the primary delivery point  
3 to the interconnection between PNGTS and the Granite Bridge Pipeline, thus providing  
4 incremental volumes to meet projected demand.

5 As discussed in Section VII.B below, the PNGTS precedent agreement has a TBO  
6 component which provides for transportation capacity from the Dawn Hub on Union Gas  
7 and the TCPL Canadian Mainline, and PNGTS will assign the associated transportation  
8 capacity on each pipeline (i.e., Union Gas and the TCPL Canadian Mainline) to  
9 EnergyNorth upon the in-service date for each phase. With respect to rates, expansions on  
10 Union Gas and the TCPL Canadian Mainline are typically rolled into the overall cost of  
11 service for the respective pipeline system and the rates for service are set by the Ontario  
12 Energy Board (for Union Gas) or the National Energy Board of Canada (for the TCPL  
13 Canadian Mainline). This regulatory approach for toll setting is similar to the approach  
14 used by the FERC to set the rates for certain of the Company's transportation and storage  
15 contracts on Tennessee, National Fuel, Dominion, and Iroquois. Finally, the rate for the  
16 capacity on PNGTS is a negotiated rate with a cap on cost overruns, which not only limits  
17 the Company's exposure but provides cost and rate certainty to its customers.

18 **Q. Please discuss the qualitative benefits of the Granite Bridge LNG facility.**

19 A. There are four primary qualitative benefits associated with the proposed Granite Bridge  
20 LNG facility:

- 1           • First, the Granite Bridge LNG facility will increase the Company's on-system  
2           assets, which will increase the reliability of the Company's gas supply portfolio.  
3           As demonstrated in the LNG benchmarking analysis discussed above, EnergyNorth  
4           does not have the same level of LNG vaporization relative to Design Day demand  
5           as its peer group, nor does EnergyNorth have the days of LNG storage that is typical  
6           of New England LDCs. The Granite Bridge LNG facility will be a cost-effective  
7           addition to the Company's peaking resources, and will also ensure the continued  
8           flow of natural gas supply to the Company's customers should there be a restriction  
9           on the upstream pipelines.
- 10          • Second, the Granite Bridge LNG facility will provide for load following service,  
11          which greatly enhances the flexibility of the Company's resource portfolio. As  
12          demand within a day fluctuates, the Company can use the vaporization flexibility  
13          of the Granite Bridge LNG facility to meet that change in demand and reduce its  
14          exposure to volatile intraday spot gas purchase prices and pipeline imbalance  
15          charges.
- 16          • Third, the Granite Bridge LNG facility diversifies the Company's supply assets,  
17          reduces price volatility during peak periods, and is a peaking supply resource to  
18          meet the growing requirements for Design Day and peak period demand. The  
19          Granite Bridge LNG facility provides the Company with a physical hedge product  
20          that allows EnergyNorth to purchase supply during the off-peak season, when  
21          prices are generally lower, liquefy that supply, store it in its tank, and vaporize the

1 liquid to meet demands during the peak period when natural gas prices are generally  
2 higher.

- 3 • Finally, the Granite Bridge LNG facility provides EnergyNorth with a cost-  
4 effective option with respect to maintaining or retiring the Company's aging  
5 propane facilities. As demonstrated by the results of the Company's SENDOUT  
6 analysis in Table 9 above, the Granite Bridge LNG facility provides the Company  
7 with a low to no cost option to retain or retiring the propane facilities.

8 **Q. How did EnergyNorth determine the appropriate volumes for each of the resource**  
9 **options?**

10 A. Given the projected Design Day and peak season demand requirements, and since the  
11 ENGIE contract is the only available resource option to provide incremental supply on a  
12 firm basis to EnergyNorth's city-gates in the interim period, the Company concluded that  
13 the full capacity of 7,000 Dth per day offered by ENGIE would be appropriate. As  
14 discussed above, the ENGIE contract would provide the Company with several unique  
15 qualitative benefits, and would allow the Company to transition to the long-term resource  
16 portfolio by providing incremental supply through March 2022.

17 As shown in Table 9 above, the SENDOUT® Resource Mix module selected the  
18 TCPL/PNGTS capacity from Dawn in all four resource planning scenarios. The resulting  
19 Resource Mix volume for the TCPL/PNGTS capacity ranged from 6,840 Dth per day in  
20 the Alternative Case to 9,470 Dth per day in the Base Case scenario, and from 9,260 Dth  
21 per day to 19,230 Dth per day in the Base Case Sensitivity and Alternative Case Sensitivity

1 scenarios, respectively. Based on the Company's review of the analytical results, and  
2 taking into consideration the qualitative benefits associated with the TCPL/PNGTS  
3 capacity, EnergyNorth concluded that some volume on the TCPL/PNGTS transportation  
4 path from Dawn would be appropriate at this time.<sup>70</sup> Given the long-term capacity  
5 commitment associated with the TCPL/PNGTS contract (a 22-year contract term), the  
6 Company determined a volume level of 5,000 Dth per day allows the Company to meet its  
7 requirements, while maintaining near term portfolio flexibility, which best positions the  
8 Company to adjust to changing market conditions.

9 **Q. Did the Company analyze different storage tank sizes for the Granite Bridge LNG**  
10 **facility?**

11 **A.** Yes, it did. As discussed in Section VII.C, the Company conducted an assessment of  
12 engineering requirements and construction costs associated with an on-system LNG  
13 facility, which included initial capital cost estimates from Sanborn, Head & Associates  
14 ("Sanborn Head") for various storage tank sizes. With respect to the Granite Bridge LNG  
15 facility, the Company performed additional SENDOUT® analyses to determine the cost  
16 implications associated with various tank sizes. Based on the results of the SENDOUT®  
17 analyses, a facility with 2 Bcf of LNG storage capacity is the lowest cost option for its  
18 customers. Specifically, as shown in Table 10 below, the Base Case resource planning

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<sup>70</sup> The Company also analyzed the Base Case scenario using the SENDOUT® Resource Mix module for the interim period (i.e., through 2021/22). The Resource Mix results for the interim period included a TCPL/PNGTS volume of 7,120 Dth per day and zero Repsol volumes, which aligns with the Company's conclusion that contracting on the TCPL/PNGTS path from Dawn would be appropriate.

1 scenario with a 2 Bcf LNG storage facility is approximately \$12 million and \$79 million  
2 lower in total system cost than a 1.2 Bcf or 2.5 Bcf tank size, respectively.

3 **Table 10: EnergyNorth SENDOUT® Model Runs – LNG Tank Size Scenarios**

| Resource Planning Scenario | Exhibit No. | Granite Bridge LNG | Propane Facilities | Resource Mix Results |                  |                 | Total System Cost (\$000) | Comparison to 2.0 Bcf Tank (\$000) |
|----------------------------|-------------|--------------------|--------------------|----------------------|------------------|-----------------|---------------------------|------------------------------------|
|                            |             |                    |                    | Dawn (Dth/day)       | Repsol (Dth/day) | ENGIE (Dth/day) |                           |                                    |
| Base Case                  | WRK/JMS-4   | 2.0 Bcf            | No                 | 9,470                | 0                | 0               | \$2,797,138               | \$ -                               |
| Base Case                  | WRK/JMS-8   | 1.2 Bcf            | No                 | 12,550               | 0                | 1,850           | \$2,809,145               | \$ 12,007                          |
| Base Case                  | WRK/JMS-9   | 2.5 Bcf            | No                 | 8,700                | 0                | 0               | \$2,876,272               | \$ 79,134                          |

4  
5 **Q. How will the addition of each resource option impact the Company’s Design Day**  
6 **resource shortfalls?**

7 A. The ENGIE contract provides EnergyNorth with incremental supply of 7,000 Dth per day  
8 in the interim period from November 1, 2018, to March 31, 2022. As discussed previously,  
9 given the current deliverability to the Company’s city-gates, the TCPL/PNGTS contract  
10 would not provide the Company with incremental capacity until the Granite Bridge  
11 Pipeline is placed in-service. Specifically, beginning on November 1, 2021, the  
12 TCPL/PNGTS contract would provide EnergyNorth with incremental capacity of 5,000  
13 Dth per day through the end of the analysis period. Table 11 below summarizes the  
14 Company’s Design Day demand and resources with the addition of the proposed ENGIE  
15 and TCPL/PNGTS contracts.

**Table 11: EnergyNorth Design Day Resource Shortfall  
with Addition of Proposed Resource Options (Dth)**

| Split-Year (Nov-Oct) | Design Day Demand | Current Design Day Resources, including Propane | Reserve / (Deficiency) including Propane | Reserve / (Deficiency) including Propane and ENGIE | Reserve / (Deficiency) including Propane, ENGIE and TCPL/PNGTS |
|----------------------|-------------------|---|--|--|--|
| 2017/18              | 156,822           | 162,033   | 5,211                                    | 5,211  | 5,211  |
| 2018/19              | 160,989           | 155,033   | (5,956)                                  | 1,044  | 1,044  |
| 2019/20              | 164,640           | 155,033   | (9,607)                                  | (2,607)  | (2,607)  |
| 2020/21              | 168,934           | 155,033   | (13,901)                                 | (6,901)  | (6,901)  |
| 2021/22              | 173,917           | 155,033   | (18,884)                                 | (11,884)   | (6,884)  |
| 2022/23              | 179,382           | 155,033   | (24,349)                                 | (24,349)   | (19,349)   |
| 2023/24              | 184,432           | 155,033   | (29,399)                                 | (29,399)   | (24,399)   |
| 2024/25              | 188,856           | 155,033   | (33,823)                                 | (33,823)   | (28,823)   |
| 2025/26              | 192,933           | 155,033   | (37,900)                                 | (37,900)   | (32,900)   |
| 2026/27              | 196,785           | 155,033   | (41,752)                                 | (41,752)   | (36,752)   |
| 2027/28              | 199,954           | 155,033   | (44,921)                                 | (44,921)   | (39,921)   |
| 2028/29              | 203,491           | 155,033   | (48,458)                                 | (48,458)   | (43,458)   |
| 2029/30              | 206,790           | 155,033   | (51,757)                                 | (51,757)   | (46,757)   |
| 2030/31              | 210,016           | 155,033   | (54,983)                                 | (54,983)   | (49,983)   |
| 2031/32              | 212,972           | 155,033   | (57,939)                                 | (57,939)   | (52,939)   |
| 2032/33              | 215,843           | 155,033   | (60,810)                                 | (60,810)   | (55,810)   |
| 2033/34              | 218,828           | 155,033   | (63,795)                                 | (63,795)   | (58,795)   |
| 2034/35              | 221,631           | 155,033   | (66,598)                                 | (66,598)   | (61,598)   |
| 2035/36              | 224,148           | 155,033   | (69,115)                                 | (69,115)   | (64,115)   |
| 2036/37              | 226,863           | 155,033   | (71,830)                                 | (71,830)   | (66,830)   |
| 2037/38              | 229,590           | 155,033   | (74,557)                                 | (74,557)   | (69,557)   |

**Q. Please describe how the Company will manage any resource shortfall or reserve capacity shown in Table 11 above.**

**A.** Prior to the proposed in-service date of the Granite Bridge LNG facility, the Company is projected to have a Design Day capacity deficiency of 2,607 Dth per day in 2019/20, 6,901 Dth per day in 2020/21, and 6,884 Dth per day in 2021/22. Once operational, the proposed Granite Bridge LNG facility would meet the Company’s Design Day resource needs in the 2022/23 through 2037/38 time period. In addition, the Granite Bridge LNG facility

1 provides the Company with the option to retire the aging propane facilities. If the existing  
2 propane facilities were retired, the Design Day resource shortfall shown in Table 11 above  
3 would increase from 69,557 Dth per day to 104,157 Dth per day in 2037/38, which can be  
4 met by the Granite Bridge LNG facility.

5 As a temporary solution to meet the Design Day resource shortfall in the interim period,  
6 EnergyNorth will likely need to increase the utilization of the Company's existing LNG  
7 facilities beyond the daily operational and storage capacity of 12,600 Dth and contract for  
8 additional winter liquid-only supply and LNG trucking service. By contracting for this  
9 winter refill arrangement, EnergyNorth would be able to cycle the LNG inventory and use  
10 the available daily vaporization capacity as a short-term solution to meet the Company's  
11 Design Day deficiency. At this time, the Company has not contracted for additional liquid-  
12 only supply or dedicated trucking service. If it is determined that there is still a capacity  
13 deficiency for those upcoming winters, the Company will issue an RFP for liquid refill in  
14 the preceding summers to meet the then-anticipated supply shortfall.

15 With regard to any reserve capacity, the Company will continue its efforts to mitigate the  
16 cost of underutilized capacity as it does today through various resource optimization  
17 strategies, including asset management agreements, capacity releases, and off-system  
18 sales. In addition, the Company will continue to review the feasibility of maintaining its  
19 propane facilities after the Granite Bridge LNG facility is placed in-service. Depending on  
20 the condition of the facilities and the market dynamics at the time, a combination of the



1 facilities could be “mothballed” if that is deemed as being in the best interest of the  
2 customers.

3 **Q. Please summarize the conclusions regarding the Company’s long-term supply**  
4 **strategy (i.e., the Granite Bridge Project and TCPL/PNGTS pipeline capacity).**

5 A. As demonstrated by the Company’s quantitative and qualitative analyses, the Granite  
6 Bridge LNG facility and TCPL/PNGTS pipeline capacity when paired with the Granite  
7 Bridge Pipeline results in a best-cost portfolio for its customers over the long-term. The  
8 Granite Bridge LNG facility is a cost-effective resource that will also provide the Company  
9 with significant qualitative benefits, which increase the reliability and flexibility of the  
10 EnergyNorth resource portfolio and diversifies the Company’s supply assets. In addition,  
11 the Granite Bridge LNG facility will provide the Company with flexibility to maintain or  
12 retire the Company’s propane facilities. The TCPL/PNGTS capacity will access natural  
13 gas supplies at the Dawn Hub and, together with the Granite Bridge Project, provide the  
14 Company with several qualitative benefits (e.g., increased reliability, supply diversity, and  
15 delivery flexibility). The Granite Bridge Pipeline will be required to facilitate the delivery  
16 of each of these resource options and the associated benefits.

17 **Q. Please summarize the Company’s conclusion regarding the interim resource option,**  
18 **the ENGIE contract?**

19 A. Prior to the implementation of the long-term resource strategy, the Company needed to  
20 develop an interim gas supply strategy to meet its growing incremental demand  
21 requirements and associated resource shortfall on Design Day and peak winter periods.

1 The incremental supply provided by the ENGIE contract helps to meet that near-term  
2 demand requirement, and is a cost-effective resource that provides unique qualitative  
3 benefits to the Company (e.g., firm deliveries to the Company's city-gates, and  
4 combination vapor and/or liquid service).

5 **VII. SUMMARY OF ENERGYNORTH'S SUPPLY STRATEGY**

6 **Q. Please summarize the supply and capacity contracts and proposed infrastructure**  
7 **projects for which the Company seeks Commission approval.**

8 A. As detailed in the Fleck/DaFonte Testimony, EnergyNorth is seeking approval from the  
9 Commission for its interim and long-term natural gas supply strategy, which includes: (1)  
10 the supply and capacity contract with ENGIE; (2) the precedent agreement with PNGTS  
11 that includes capacity on PNGTS, the TCPL Canadian Mainline, and Union Gas; (3) the  
12 development and construction of the proposed Granite Bridge Pipeline to facilitate the  
13 delivery of supplies from PNGTS and the Granite Bridge LNG facility; and (4) the  
14 development and construction of the Granite Bridge LNG facility. A review of the  
15 associated tolls/rates, operational parameters, key contract terms, and timing of resource  
16 availability for each of the gas supply and capacity resources is provided below.

17 **A. ENGIE Capacity**

18 **Q. Please summarize the ENGIE service for which EnergyNorth has requested approval.**

19 A. EnergyNorth entered into a Transaction Confirmation with ENGIE on July 19, 2017, which  
20 is subject to a Base Contract between the parties dated December 19, 2011. The four-year  
21 contract with ENGIE begins in November 2018 and terminates in March 2022; and

1 provides EnergyNorth with up to 7,000 Dth per day of firm, delivered service to  
2 EnergyNorth city-gates. In addition, the total annual contract quantity (“ACQ”) of 630,000  
3 Dth can be delivered to EnergyNorth as vapor and/or liquid.

4 The price structure of the ENGIE contract includes a demand charge, or call payment, of  
5 [REDACTED] per year, and the commodity price is based on [REDACTED]  
6 [REDACTED]. This price structure reflects the delivered nature of the ENGIE contract where  
7 supply and capacity are bundled for a city-gate product. In addition, the price structure  
8 reflects the option to receive the ENGIE volume as liquid.

9 **Q. Please discuss the regulatory approval provision outlined in the Transaction**  
10 **Confirmation between EnergyNorth and ENGIE.**

11 A. EnergyNorth has negotiated a provision with ENGIE that allows the Company to terminate  
12 the arrangement should the Commission not approve the service as outlined in the  
13 Transaction Confirmation. The deadline for the Commission’s decision with respect to  
14 approval of this contract is [REDACTED]

15 [REDACTED] The regulatory approval provision provides the Company with  
16 the opportunity to seek and receive approval for the service outlined in the Transaction  
17 Confirmation prior to initiation of service, thus mitigating risk for the Company and its  
18 customers.

1 **Q. Does the ENGIE service require expansion of existing pipeline facilities or any other**  
2 **construction requirements?**

3 A. No, it does not. The ENGIE service as contracted by EnergyNorth can be provided by  
4 existing infrastructure so there is no need for facility expansion or construction. As a result,  
5 the ENGIE service is not subject to project development risk.

6 **B. PNGTS Precedent Agreement**

7 **Q. Please summarize the precedent agreement with PNGTS for which EnergyNorth**  
8 **requests approval.**

9 A. EnergyNorth has entered into a precedent agreement with PNGTS associated with the  
10 Portland XPress Project on October 4, 2017, for 5,000 Dth per day of firm transportation  
11 capacity from the Dawn Hub (the receipt point) to Dracut (the delivery point), which will  
12 be phased in over three years. Specifically, the Company will receive 1,784 Dth per day  
13 beginning November 2018, 4,432 Dth per day in November 2019, and 5,000 Dth per day  
14 in November 2020. As structured in the PNGTS precedent agreement, EnergyNorth has  
15 contracted for transportation capacity on the following pipelines:

- 16 • Union Gas: EnergyNorth has contracted with Union Gas via a TBO in the TCPL  
17 Canadian Mainline agreement from the Dawn Hub to an interconnection with the  
18 TCPL Canadian Mainline at Parkway, Ontario;
- 19 • TCPL Canadian Mainline: The Company has a contract with the TCPL Canadian  
20 Mainline from Parkway to East Hereford (i.e., the interconnection point between

1           the TCPL Canadian Mainline and PNGTS) via a TBO in the PNGTS precedent  
2           agreement; and

- 3           • PNGTS: EnergyNorth has contracted for transportation capacity from East  
4           Hereford to Dracut, which is the interconnection point between PNGTS and  
5           Tennessee.

6           As discussed, the PNGTS precedent agreement structure has a TBO component that allows  
7           EnergyNorth to contract with PNGTS for the entire path from the Dawn Hub to Dracut.  
8           PNGTS will assign the associated transportation capacity on each pipeline (i.e., Union Gas,  
9           TCPL Canadian Mainline) to EnergyNorth upon the in-service date for each phase. This  
10          structure enhances the regulatory approval requirement as discussed below.

11   **Q.    Does the PNGTS precedent agreement provide EnergyNorth with flexibility with**  
12   **respect to [REDACTED]?**

13   **A.    Yes, the precedent agreement negotiated by the Company with PNGTS provides**  
14   **significant flexibility with respect to [REDACTED]**  
15   **[REDACTED]**  
16   **[REDACTED]**  
17   **[REDACTED]**  
18   **[REDACTED]**

1 **Q. Please discuss the negotiated rate and the associated cap on construction cost**  
2 **overruns.**

3 A. As outlined in the PNGTS precedent agreement, EnergyNorth has negotiated a fixed daily  
4 rate of [REDACTED] per Dth on PNGTS for the initial term of the contract. [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 **Q. Please discuss the rates for transportation service on the TCPL Canadian Mainline**  
10 **and Union Gas.**

11 A. The capacity service provided by the TCPL Canadian Mainline and Union Gas is regulated  
12 by the National Energy Board of Canada and the Ontario Energy Board, respectively. As  
13 such, the Company, similar to other shippers on these pipelines, will pay a cost of service  
14 rate as approved by the specific regulatory authority. This type of rate structure is also  
15 similar to the approach used by the FERC to regulate rates in certain of the legacy  
16 transportation and storage contracts in the Company's portfolio.

17 **Q. Please discuss the regulatory approval provision outlined in the PNGTS Precedent**  
18 **Agreement.**

19 A. EnergyNorth negotiated a provision with PNGTS that allows the Company to terminate  
20 the arrangement should the Commission not approve the contract as structured. The  
21 deadline for the Commission's decision with respect to approval of this precedent

1 agreement is [REDACTED]

2 [REDACTED] The regulatory approval provision provides the Company with the opportunity  
3 to seek and receive approval for the terms and conditions of service as outlined in the  
4 precedent agreement prior to initiation of service, thus mitigating risk for the Company and  
5 its customers.

6 **Q. Does the regulatory approval clause in the PNGTS precedent agreement include the**  
7 **transportation capacity on the TCPL Canadian Mainline and Union Gas?**

8 A. Yes, it does. Since EnergyNorth executed one contract with PNGTS for all three service  
9 components (i.e., transportation on Union Gas, the TCPL Canadian Mainline, and  
10 PNGTS), the regulatory approval clause applies to all three components.

11 **Q. Does the PNGTS service require expansion of existing pipeline facilities or any other**  
12 **construction requirements?**

13 A. Yes, it does. As part of the approximately \$80 million Portland XPress Project, PNGTS  
14 will need to develop and construct certain enhancements to existing infrastructure,  
15 including upstream capacity expansions.<sup>71</sup> These facility additions are relatively minor  
16 and, in the case of PNGTS, are upgrades at certain compressor stations. Given the  
17 relatively minimal construction required, the capacity associated with the PNGTS  
18 precedent agreement is likely subject to minimal development risk.

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<sup>71</sup> See, TC PipeLines, LP Announces 2017 Third Quarter Financial Results, News Release, November 6, 2017.

1 **C. Granite Bridge Project**

2 **Q. Please describe the project facilities associated with the Granite Bridge Project.**

3 A. As detailed in the Fleck/DaFonte Testimony, the proposed Granite Bridge Project is  
4 comprised of (i) the Granite Bridge Pipeline, which provide a second delivery feed to the  
5 EnergyNorth service area by November 1, 2021; and (ii) the Granite Bridge LNG facility,  
6 which would connect to the proposed Granite Bridge Pipeline and be placed in service by  
7 April 1, 2022.

8 **Q. Has the Company assessed the costs of the proposed Granite Bridge Pipeline and  
9 Granite Bridge LNG facility?**

10 A. Yes, EnergyNorth has conducted a detailed assessment of the engineering, regulatory and  
11 permitting requirements, and expected costs. Specifically, an estimate of the initial capital  
12 cost of the Granite Bridge Lateral was developed based on a conceptual engineering design  
13 provided by CHA. For the Granite Bridge LNG facility, EnergyNorth has engaged Sanborn  
14 Head to provide a detailed evaluation of the engineering requirements and construction  
15 costs associated with an on-system LNG facility.

16 **Q. What is the initial capital cost estimate for the proposed Granite Bridge Pipeline?**

17 A. The initial capital cost estimate to construct the proposed Granite Bridge Pipeline is  
18 approximately \$110.0 million as discussed in the direct testimony of Timothy S. Lyons.

19 **Q. Please describe the estimated daily rate for the Granite Bridge Pipeline.**

20 A. The Company used the following four-step process to develop a levelized cost of service  
21 and resulting daily rate estimate for the Granite Bridge Pipeline: (1) the likely path for the



1 Granite Bridge Pipeline was identified resulting in an approximate length of the pipeline;  
2 (2) a cost per mile to construct the pipeline was developed and applied to the estimated  
3 length of the pipeline based on conceptual engineering completed by CHA; (3) a cost  
4 estimate for two gate stations on either end of the pipeline in Manchester and Stratham, as  
5 well as a metering station connected to the Granite Bridge LNG facility in Epping, were  
6 also considered as part of the cost of the pipeline; (4) certain required assumptions for a  
7 levelized cost of service model were developed, including financial elements (e.g., cost of  
8 capital, income and property taxes, and depreciation) and operational costs (e.g., O&M  
9 expenses); and (5) the various inputs and assumptions were modeled in an Excel-based  
10 cost of service model. The results of this modeling effort produced an estimated daily rate  
11 of approximately \$0.47 per Dth based on the estimated levelized annual cost of \$12.8  
12 million and capacity of 75,000 Dth per day for the Granite Bridge Pipeline. Please see the  
13 direct testimony of Timothy S. Lyons for a more detailed discussion of the levelized cost  
14 of service model and Granite Bridge Pipeline cost estimate.

15 **Q. Please outline the cost estimate for the proposed Granite Bridge LNG facility.**

16 A. The initial capital cost estimate to construct the proposed Granite Bridge LNG facility is  
17 approximately \$201.7 million as discussed in the direct testimony of Timothy S. Lyons.

18 **Q. Has EnergyNorth estimated the annual levelized cost associated with the proposed  
19 Granite Bridge LNG facility?**

20 A. Yes, it has. Specifically, the Company developed a levelized cost of service model that  
21 calculated the annual cost of service associated with the proposed Granite Bridge LNG

1 facility under certain financial and operating assumptions (e.g., capital structure, income  
2 and property taxes, depreciation, and O&M expenses). The results of the levelized cost of  
3 service model is an annual cost of approximately \$28.0 million. Please see the direct  
4 testimony of Timothy S. Lyons for more detail regarding the levelized cost of service  
5 analysis for the proposed Granite Bridge LNG facility.

6 **Q. How will EnergyNorth meet the projected increase in demand if the supply and  
7 capacity contracts and investment decisions are not approved by the Commission?**

8 A. In the interim period, the ENGIE contract is the only incremental supply option available  
9 to the Company at this time. Should the Commission not approve the ENGIE contract,  
10 EnergyNorth would not be able to meet the resource deficiency in the near-term as there  
11 are no available alternatives to provide incremental supply to the Company's city-gates.  
12 Although EnergyNorth could increase its reliance on its existing supplemental peaking  
13 LNG and propane resources, that option would not be a viable long-term solution. The  
14 Company's propane facilities are more than 50 years old and require continued investment  
15 in maintenance, and the limited storage capacity of the existing LNG facilities would  
16 require frequent trucking of LNG to replenish the Company's inventory, which could pose  
17 significant reliability concerns. It is also important to note that even with the inclusion of  
18 the ENGIE contract, EnergyNorth would still need to increase its reliance on the existing  
19 peaking facilities to meet the Company's incremental demand requirements in the 2019/20  
20 to 2021/22 time period (as discussed in Section VI.B).

1 EnergyNorth's quantitative and qualitative analyses demonstrate that a gas supply resource  
2 portfolio including pipeline transportation on TCPL/PNGTS from Dawn, in conjunction  
3 with investments in the Granite Bridge Pipeline and the Granite Bridge LNG facility,  
4 results in the best-cost portfolio to reliably meet the long-term requirements of its  
5 customers. Should the Commission not approve EnergyNorth's strategy regarding long-  
6 term supply resources, the Company would need to consider other available capacity  
7 alternatives in the marketplace at the time the Commission's decision is issued. An  
8 expansion of the TGP Concord Lateral, if it is viable at that time, would be an alternative  
9 for incremental capacity to the Company's city-gates. Other supply resource alternatives  
10 would be revised values for PNGTS, ENGIE, or Repsol should those options still be viable  
11 at that time. However, without incremental capacity to the EnergyNorth city-gates, those  
12 options alone would not provide incremental supply to meet the Company's projected  
13 demand requirements.

14 **VIII. CONCLUSION**

15 **Q. Please summarize the conclusions with respect to the Company's natural gas supply**  
16 **strategy and associated infrastructure development and contract decisions to meet its**  
17 **projected long-term demand requirements.**

18 **A.** As discussed herein, the Company is forecasting continued growth in natural gas demand,  
19 particularly in the Design Day and winter periods, from customers within its existing  
20 footprint and from customers in new service areas. To meet this forecasted demand and to  
21 increase the reliability, flexibility, and diversity of its natural gas supply portfolio,  
22 EnergyNorth has developed a comprehensive natural gas supply strategy based on

1 extensive quantitative and qualitative analyses of reasonably available resource  
2 alternatives. As a result, the Company is requesting approval of its contract with ENGIE  
3 and the precedent agreement with PNGTS, in conjunction with the authority to develop the  
4 Granite Bridge Pipeline and Granite Bridge LNG facility.

5 The interim and long-term supply strategy positions the Company to: (i) serve natural gas  
6 demand requirements under various scenarios; (ii) provide energy choice to more New  
7 Hampshire communities, businesses, and residents; and (iii) significantly increase the  
8 reliability of the gas supply portfolio by adding a second feed (Granite Bridge Pipeline)  
9 and a flexible on-system asset (Granite Bridge LNG facility). Importantly, the Company's  
10 plan for a long-term natural gas portfolio results in the lowest total system cost for the  
11 customers of EnergyNorth as illustrated by the results of the SENDOUT® analysis, and  
12 provides EnergyNorth with a no cost option to retire some or all of the aging propane assets.

13 **Q. Does this conclude your testimony?**

14 **A.** Yes, it does.