STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DG 17-198

IN THE MATTER OF:
LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES
PETITION TO APPROVE FIRM SUPPLY AND TRANSPORTATION AGREEMENTS AND THE GRANITE BRIDGE PROJECT

DIRECT TESTIMONY OF

JOHN ANTONUK, JOHN ADGER, AND JAMES LETZELTER
OF
THE LIBERTY CONSULTING GROUP

REDACTED

SEPTEMBER 13, 2019

<u>Introduction</u>

Q. Please state your names and addresses.

A. My name is John Antonuk. I am President of The Liberty Consulting Group ("Liberty Consulting") and I have directed the work that has led to this testimony.

My name is John Adger. I am a Senior Consultant for Liberty Consulting.

My name is Dr. James Letzelter. I am an Executive Consultant for Liberty Consulting.

Our business address is c/o The Liberty Consulting Group, 1451 Quentin Road, Suite 400 #343, Lebanon, PA 17042.

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

A. Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (EnergyNorth, Liberty Utilities, or the Company) in this proceeding seeks Commission approval of:

- A four-year contract with Constellation LNG, LLC (Constellation)[1] for a 90-day winter supply service of up to 7,000 Dth/day for the winters of 2018/19 through 2021/22
- A 22-year contract with the Portland Natural Gas Transportation System (PNGTS) for 5,000 Dth/day of year-round firm pipeline transportation capacity from Dawn, Ontario, to EnergyNorth delivery points

[1] Following an October 1, 2018 acquisition of the Everett Liquefied Natural Gas Facility, Constellation became the assignee of an ENGIE Gas & LNG, LLC ("ENGIE") and Liberty Utilities contract, which is among the items under review by the Commission in this docket. (Motion of Constellation LNG, LLC for Leave to Intervene Out-of-Time (12/13/18) at 1).

- A new 16-inch high-pressure Granite Bridge Pipeline connecting with the Concord Lateral near Manchester, New Hampshire
- A new two-billion-cubic-foot LNG manufacturing and storage facility (the Granite Bridge LNG Facility) to be located in Epping, NH and connected to the Granite Bridge Pipeline (collectively, the Granite Bridge Project).

We have evaluated Liberty Utilities' request for these approvals, following examination of its testimony in support of those requests, review of responses to numerous data requests by us and by others, and participation in a number of technical sessions. This testimony summarizes the results of our evaluation, and presents our recommendations with respect to approval of the Company's requests and the reasons for those recommendations.

Q. Please provide summaries of your qualifications in this matter.

A. John Antonuk is a founder of The Liberty Consulting Group, which has served more than 40 utility regulatory authorities and a similar number of energy utilities across more than thirty years of service. He has served as the firm's president for many years. He has managed over 200 Liberty Consulting projects. Most of them have examined utility management and operations, and dozens have addressed the areas of natural gas and electricity supply planning and energy acquisition. His work on behalf of this Commission and its Staff extends across more than two decades. It includes directing and testifying about the results of a recent examination of a range of Liberty Utilities and affiliate functions and activities, including program and project planning and execution.[2] Members of that team conducted a review in 2017 to assess management's progress in implementing the audit's recommendations.[3]

Mr. Adger has led the firm's Natural Gas Practice Area for two decades. Since leaving government service as an Office Director at the U. S. Federal Energy Regulatory Commission, he has served clients in all segments of the natural gas industry in the United States (U.S.) and Canada. He began his association with The Liberty Consulting Group in 1991, joining the firm full-time in 1994.

Mr. Adger has extensive experience with natural gas in the Northeast U.S. and Maritimes Canada. From late 1999 through 2004, he served as an adjunct resource (termed "extension") of the Staff of Connecticut's Department of Public Utility Control, predecessor to today's Public Utilities Regulatory Authority. He participated in a number of proceedings during that period, including that agency's consideration of an LNG facility proposed to be constructed in Waterbury, Connecticut. The facility was authorized, and Mr. Adger returned in 2007 to assist with the Staff's evaluation of its costs. In 2013, he returned as a member of a Liberty Consulting team to assist the Staff in evaluating the Natural Gas Infrastructure Expansion Plan of Connecticut's gas distribution companies. That plan envisioned increasing the number of gas customers in Connecticut by almost 50 percent over 10 years.

[2] See The Liberty Consulting Group, "Final Report on a Management and Operations Audit of the Customer Service and Accounting Functions of Liberty Utilities," presented to the New Hampshire Public Utility Commission, August 12, 2016. The Liberty Consulting team that produced that report filed testimony about its investigations on December 16, 2016, in Docket No. DE 16-383.

[3] See The Liberty Consulting Group, "Recommendations Verification of Liberty Utilities", presented to the New Hampshire Public Utility Commission on November 1, 2017, filed as attachment SPF-8 in the Direct Testimony of Steven P. Frink on November 30, 2017, in Docket No. DG-17-048.

Mr. Adger was also a member of Liberty Consulting's team that served Nova Scotia's Utility and Review Board for 14 years (2004-2018), examining Nova Scotia Power's fuel-supply planning and management. His responsibilities included fuel-requirements forecasting and natural-gas supply planning, contracting, and management.

In New Hampshire, Mr. Adger led a Liberty Consulting team that evaluated EnergyNorth's supply planning and asset-management agreements in 2004 and 2005. That assignment included a review of EnergyNorth's then-current Integrated Resource Plan. The team returned in 2007 to assist the Commission Staff in its evaluation of EnergyNorth's proposal to enter a contract with the Tennessee Gas Pipeline Company (TGP) to expand the Concord Lateral. In early 2008, Mr. Adger and a colleague filed testimony in Docket No. DG 07-101 supporting the Company's proposal, which this Commission accepted. That expansion is covered by what EnergyNorth now refers to as its "Dracut 30" transportation contract with TGP.

Mr. Adger is currently serving as Lead Consultant for a comprehensive examination of the natural gas supply procurement and management practices of Northern Utilities, Inc.'s Maine Division for the Maine Public Utilities Commission. Northern also provides natural gas service in parts of New Hampshire. The personnel and processes used in Maine also support Northern's gas operations in New Hampshire.

Dr. James Letzelter is a management consultant with over 30 years of experience in the energy industry, having served in management consultant, project manager, and executive positions. His career includes roles as a Principal of Hagler Bailly Consulting, Managing Director of Platts Research & Consulting, and President of GenMetrix. At Liberty Consulting, Dr. Letzelter serves regulatory agencies with his expertise in energy markets, asset valuation, financial analyses, and asset optimization. Previously for the New Hampshire Public Service Commission, Dr. Letzelter developed a detailed asset valuation model to predict the value of Eversource's power plants.

Attachment 1 of this testimony present more complete descriptions of our backgrounds and experience.

Q. Please summarize your understanding of the Company's proposals in this proceeding.

A. The Company refers to its Least Cost Integrated Resource Plan (LCIRP), filed in October 2017 in Docket No. DG 17-152, as establishing a need for additional peak-day natural gas supply capacity. In this proceeding (Docket No. DG 17-198), the Company requests Commission approval for the following:

- A four-year contract with Constellation for a 90-day winter gas supply service of up to 7,000 Dth/day for the winters of 2018/19 through 2021/22 (since extended to 2022/23). This contract provides for the delivery of liquefied natural gas (LNG), trucked to EnergyNorth's peaking facilities, or as vapor, delivered to EnergyNorth's city gates on pipeline capacity under contract to Constellation. The Company characterizes this supply as a short-term solution, to be used until its proposed Granite Bridge Project is complete and in service.

- A 22-year contract with the Portland Natural Gas Transportation System (PNGTS) for 5,000 Dth/day of year-round firm pipeline transportation capacity from Dawn, Ontario, to EnergyNorth delivery points. This contract includes capacity on upstream pipeline systems TransCanada PipeLines (TCPL) and the Union Gas system in Ontario, Canada. The contract began in November 2018, and will deliver initially to TGP's Concord Lateral, for re-delivery to EnergyNorth. As proposed by the Company, when the Granite Bridge Project is complete and in service, the delivery point would move to the interconnect of the Granite Bridge Pipeline with the "Joint Facilities Pipeline," near Stratham, New Hampshire. PNGTS and the Maritimes & Northeast Pipeline system (M&NP) jointly own the Joint Facilities pipeline, which extends from the point where the two pipelines come together, near Westbrook, Maine, to the Dracut, Massachusetts interconnect with TGP ("Dracut").
- A new 16-inch high-pressure pipeline – the Granite Bridge Pipeline -- connecting the Joint Facilities with the Concord Lateral near Manchester, New Hampshire. The costs of this pipeline are proposed to be recovered through EnergyNorth's distribution rates.
- A new two-billion-cubic-foot the Granite Bridge LNG Facility, an LNG manufacturing and storage facility to be located in Epping, NH and connected to the Granite Bridge Pipeline. The costs of this facility are proposed to be recovered in EnergyNorth's purchased-gas costs.

Q. Has the Company made any related requests for Commission approval?

A. Yes. The Company's LCIRP filing[4] requests that the Commission approve renewal of all its "legacy" contracts for pipeline and storage services. The following table lists those contracts, as identified in the LCIRP filing.[5] In that filing, the Company also recommends replacement of its propane-based peaking facilities.[6] Its subsequent Granite Bridge Project filing described its intent as to create the *option* to replace these facilities.

Contract Entity	Rate Schedule	Contract Number	MDQ/MDWQ (Dth)	Storage MSQ (Dth)	Expiration Date
Pipeline Transportation					
Union Gas System	M12	M12200	4,092	-	10/31/2022
TCPL	FT	41232	4,047	-	10/31/2022
Iroquois	RTS	470-01	4,047	-	11/1/2022
PNGTS	FT	1999-001	1,000	-	10/31/2019
TGP	FT-A (Zone 5 to Zone 6)	95346	4,000	-	11/30/2021
TGP	FT-A (Zone 5 to Zone 6)	2302	3,122	-	10/31/2020
TGP	FT-A (Zones 0,1 to Zone 6)	8587	25,407	-	10/31/2020
Underground Storage and Associated Pipeline Transportation					
TGP	FS-MA	523	21,844	1,560,391	10/31/2020
TGP	FT-A (Zone 4 to Zone 6)	632	15,265	-	10/31/2020
Honeoye	SS-NY	11234	1,957	245,280	3/31/2020
TGP	FT-A (Zone 5 to Zone 6)	11234	1,957	-	10/31/2020
Dominion	GSS	300076	934	102,700	3/31/2021
TGP	FT-A (Zone 4 to Zone 6)	11234	932	-	10/31/2020
National Fuel	FSS	O02357	6,098	670,800	3/31/2019
National Fuel	FST	N02358	6,098	-	3/31/2019

[4] Docket No. DG 17-152, LCIRP at 47 (Bates Page 051), filed 10/2/17.
[5] *Ibid.*
[6] *Ibid.* See page 48.

TGP	FT-A (Zone 4 to Zone 6)	11234	6,150	-	10/31/2020

Q. Please summarize your findings regarding the Company's projections of need for additional capacity.

A. Our examination of EnergyNorth's proposal for the Granite Bridge Project identified issues concerning key assumptions driving management's conclusion that the pipeline and LNG facility comprise a sound approach to meeting the future energy needs of EnergyNorth's customers. Our review of the Company's requirements forecast in the LCIRP proceeding found that forecast to be aggressive.

We believe that EnergyNorth's recent customer-growth experience confirms a near-term need for additional capacity over the five-year period covered by the LCIRP forecast period. However, EnergyNorth would have to experience sustained growth at its projected levels for the Granite Bridge LNG Facility to produce positive economic benefits, at currently-estimated installation costs. Even at management's estimated installation costs and its forecasted growth rates, those benefits would be barely positive - - insufficient, in our view - - to justify committing now to the LNG facility at customer cost. Variations from management's expectations with respect to estimated installation costs and forecasted growth rates risk even larger economic harm for customers.

We thus consider that relying on sustained continuation of EnergyNorth's projected customer growth rates does not form a foundation for committing now to the Granite State LNG facility. We also consider it unsound to rely on currently-projected installation costs, which form a primary driver of customer costs. We see a large potential for substantial LNG facility installation costs to grow substantially from the current estimate. Three factors underlie this observation: (a) the LNG facility's current state of development (not well advanced), (b) management's lack of familiarity with projects of this scope and complexity, and (c) in particular, a well-founded concern about reliance on management's ability to execute projects in accord with its cost estimates.

Put simply, committing now to the Granite Bridge LNG Facility, with the Company's customers at risk for the consequences of reduced demand or cost escalation, or both, has not been justified by Liberty Utilities. Despite concluding, however, that management has not presented a sound basis for proceeding now with the proposed LNG facility, we nevertheless do find sound the Company's conclusion that its needs for the next five years require additional capacity to support its gas-supply requirements. Specifically, we find increased pipeline capacity to be necessary, but we believe that management has not undertaken sufficient analysis to demonstrate that the proposed Granite Bridge Pipeline is the best alternative for providing that capacity.

We also do not find the Company's recommendation in the LCIRP proceeding to retire its propane-based peaking facilities necessary or appropriate. We consider continuing reliance on them a useful and economic element in maintaining reliable service while optimizing portfolio costs.

We address EnergyNorth's LCIRP recommendations regarding its legacy pipeline and storage capacity in our testimony filed in Docket No. 17-152 on September 6, 2019.

Q. What then do you recommend with respect to the capacity needs that you acknowledge?

A. We recommend that the Commission:

- Approve the Constellation and PNGTS contracts
- Not approve the proposed LNG facility
- Not approve the proposed Granite Bridge Pipeline, pending a robust and objective analysis of expansion of the Concord Lateral as an alternative, and of the optimum sizing of the Granite Bridge Pipeline, following elimination of the Granite Bridge LNG Facility from consideration.

<u>The Constellation and PNGTS Contracts</u>

Q. Please explain your recommendation regarding the Constellation contract.

A. We recommend, for several reason, approval of the Constellation contract to provide the near-term increase in delivery capacity that the Company needs. First, for a limited term (initially four years, now extended to five) the Constellation contract brings the option of liquid or vapor, and provides an immediate addition to EnergyNorth's gas-supply capacity because Constellation has its own contract for capacity on the Concord Lateral.

Second, it also compares favorably with the other supply options currently available. Extensive SENDOUT analyses[7] show that the Constellation supply is taken at 100 percent of

[7] Source: Company's responses to Set 6 of the Staff's data requests.

availability for the duration of the current contract, which would be allowed to expire when the proposed LNG facility would enter service. If the LNG facility does not become available, the SENDOUT analyses show extension of the Constellation contract as sound in most cases, if it remains available on the current terms.

Q. Please explain the use of SENDOUT in the context of examining the Constellation contract.

A. Industry participants broadly use SENDOUT, a natural gas-supply planning model. SENDOUT offers a well-established analytical tool for supporting investment decisions and regulatory proceedings. ABB licenses this proprietary model for use in natural gas supply-planning initiatives. SENDOUT works by using linear programming algorithms to simulate gas operations and optimize results. Linear programming forms the core of many commercial software models used to perform simulations and optimizations. SENDOUT considers demand forecasts, available supply and delivery options, and the costs associated with them to produce projections of costs for meeting demand with various combinations of supply options. It solves for the least-cost mix of options for meeting demand. Ultimately, SENDOUT provides users with an estimate of annual delivered supply cost that considers all costs.

Q. Please explain your recommendation regarding the PNGTS contract.

A. The 22-year PNGTS contract reflects a long-term commitment. We find it appropriate, based on favorable commodity prices, as an alternative for increased capacity. The contract brings access to the Dawn, Ontario supply point. Dawn promises the likelihood of lower prices and a much deeper market when compared with Dracut. EnergyNorth’s SENDOUT analyses confirm the benefits of PNGTS supply from Dawn. They show a much higher load factor when compared with the Dracut 20 and Dracut 30 contracts, both before and after the Granite Bridge Pipeline or Concord Lateral expansion alternatives would become available. That load factor difference confirms the pricing advantage of PNGTS at Dawn over purchases at Dracut.

The PNGTS contract will not bring additional capacity to EnergyNorth’s city gates until either the new Granite Bridge Pipeline is in service, or the Concord Lateral is expanded. Until that time, the supply it brings will be delivered on one of the Company’s current contracts on the Concord Lateral. The Dracut 20 and Dracut 30 contracts connect Dracut to the Company’s service territory. They are currently used to deliver gas that is purchased at Dracut.

We believe that the Company’s analyses show the need for more capacity than this contract brings, even if its rate of customer additions in its existing service territory is less than forecasted, and even if it does not secure authority to expand into additional service territories.

<u>The Granite Bridge LNG Facility</u>

Q. Explain your reasons for concluding that the Commission should not approve the Granite Bridge LNG Facility.

A. The facility as proposed would require a long-term commitment to a massive increase in supply capacity extending well beyond the Company’s forecasted requirements 20 years from now. The Company's adjusted forecasts[8] show a current peak-day capacity requirement of 164,571 Dth/day, increasing to 225,306 Dth/day in 2038/39. The current supply-capacity portfolio amounts to 162,033 Dth/day, consisting of:[9]

- 56,833 Dth/day of legacy pipeline and storage capacity contracts that connect the Company's southern New Hampshire territories to production areas in the U.S. Gulf Coast and storage areas in Pennsylvania and southern Ontario, Canada
- 1,000 Dth/day of pipeline capacity that serves the Company's Berlin service territory
- 50,000 Dth/day of current capacity on the Concord Lateral that connects the Company's southern New Hampshire city gates to the mainline TGP system at Dracut, MA
- 47,200 Dth/day of on-system peaking capacity
- The Constellation contract (7,000 Dth/day).

Attainment of the Company's forecast would add requirements of 63,273 Dth/day above the capacity of its current portfolio. Therefore, the 150,000 Dth/day capacity of the proposed LNG facility exceeds the forecasted increase by a factor of 2.37. Adding the LNG facility would triple on-system peaking resources, currently rated at 12,600[10] Dth/day from LNG and

[8] See Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen, filed in Docket No. 17-198 on March 15, 2019, at 49 (Bates Page 053).
[9] The new PNGTS contract does not add to this total until capacity is added to move it from either a delivery point on the Joint Facilities or Dracut.
[10] The LNG storage capacity is 12,600 Dth. The maximum daily design vaporization capacity of the three existing LNG facilities is 22,800 Dth, which can be achieved by refilling the storage tanks more often. See Direct Testimony of William R. Killeen and James M. Stephens, filed on December 22, 2017, in Docket No. DG 17-198, at 55 (Bates Page 167).

34,600 Dth/day from its propane-based peaking plants. It would also quadruple the capacity of the propane facilities that management might[11] retire.

Looked at another way, the addition of the Granite Bridge LNG Facility would provide 139 percent[12] of 2038/39 capacity requirements as EnergyNorth has forecasted them before retirement of the propane facilities. Even were management eventually to retire those propane facilities, the supply capacity added by the LNG storage facility would produce an excess of 23 percent above forecasted needs.[13]

Q. What economic impacts to customers of the LNG facility has EnergyNorth projected?

A. The Company performed analyses with SENDOUT to project the cost savings associated with the LNG facility. The summary is that a very large $260.5 million dollar projected capital investment[14] would result in only a 0.8 percent[15] reduction in the cost of serving customers. This marginal forecast of economic benefits to customers depends both on load growth at the sustained levels management has projected and delivery of the facility at the costs it has estimated. Even without growth and cost risks, such a small benefit would not appear to justify so large an investment today. Adding them underscores the wisdom of not exposing customers to what we view as material risks in both cases.

---

[11] In its filings in this proceeding the Company refers to the LNG Facility as providing "the option" to retire the propane facilities, suggesting that they might be retained. See, *e.g.*, the Direct Testimony of Susan L. Fleck and Francisco C. DaFonte, filed on December 22, 2017, in Docket No. DG 17-198, at 17 (Bates Page 021), lines 19-21.
[12] (162,033 + 150,000 = 312,033)/225,306 = 1.39
[13] (127,433 + 150,000 = 277,433)/225,306 = 1.23
[14] Source: Attachment Liberty Response to Staff Data Request 7-1
[15] ($2,820,168,000 (Exh. FCD/WRK-4) - $2,796,648,000 (Exh. FCD/WRK-2))/$2,820,168 = 0.008

Q. Describe your concerns about construction cost risk.

A. The Granite Bridge LNG project would require strong management and control in areas where EnergyNorth lacks substantial experience. Moreover, as we reported in our 2016 report,[16] and as we testified that year in a Liberty Utilities rate case,[17] Liberty Utilities has demonstrated an historical pattern of poor performance in project estimating and budgeting for capital projects. Quoting our December 2016 testimony, for example:

> *The audit observed very large capital expense variances in 2014 and 2015. Their frequency and magnitude confirmed a lack of management of and effective control over capital expenditures. Combined, the electric and gas businesses in New Hampshire experienced capital budget over-runs of over 70 percent in 2014, driven by many individual variances, some of them extremely large. We found large variances, both positive and negative, across a wide range of projects and project types.* (at 13)

The factors identified in our cited report and testimony diminish confidence in current estimates of project costs.

In fact, with the LNG project still at relatively low levels of engineering completion, cost estimates have already grown dramatically, underscoring the asymmetry of cost risk -- costs are far more likely to increase than to decrease as the project proceeds.

Q. What is the history of cost estimates for the Granite Bridge LNG project?

A. Management's estimates of LNG costs have increased substantially since its initial testimony in support of the project. The December 21, 2017 testimony of Mr. Lyons provided an

---

[16] The Liberty Consulting Group, "Final Report on a Management and Operations Audit of the Customer Service and Accounting Functions of Liberty Utilities," presented to the New Hampshire Public Utility Commission on August 12, 2016.

[17] NH PUC Docket No. 16-383, *In the Matter of Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities Request for Change in Rates,* Direct Testimony of John Antonuk, Randall Vickroy and Christine Kozlosky of The Liberty Consulting Group, filed December 16, 2016.

estimate of $201.7 million.[18] A more recent estimate places LNG facility costs at $246 million[19] - - a 22 percent increase. The Company's witnesses attributed this increase to changes to the initial plant design, including on-site generation, increased liquefaction capacity, and different technology for pretreatment and liquefaction.[20]

In May 2019, the Company reported varying stages of engineering and design completion for LNG project components; *e.g.*, LNG tank (approximately 40 percent complete), balance of plant (approximately 25 percent complete), and site engineering (approximately 15 percent complete).[21] Management expects completion of a recently-commissioned Front End Engineering and Design study around the beginning of October 2019. That study is intended to reflect design engineering at a minimum of 30 percent complete.[22] Management expects the cost estimate resulting from the engineering advance to produce a confidence interval around the estimate from negative 10 to 20 percent to positive 10 to 30 percent.[23]

Even if the forthcoming estimate can be considered reliable in setting such a range, its 10 to 30 percent exposure on the cost-increase side creates risk substantially greater than the barely positive economic impacts projected by management, even if its growth assumptions prove accurate. Given, at best, the extremely thin margin postulated by EnergyNorth, the risk of

[18] Direct Testimony of Timothy S. Lyons, filed on December 21, 2017, in Docket No. DG 17-198, at 18 (Bates Page 092)
[19] Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen, filed on March 15, 2019, in Docket No. DG 17-198, at 35 (Bates Page 039).
[20] *Ibid.*, at 33 (Bates Page 037).
[21] Source: Response to DR Staff 7-27.
[22] Source: Response to DR Staff 7-2.
[23] Source: Responses to DRs Staff 7-2 and 7-27.

cost increase is far too high in likelihood and magnitude to justify the LNG facility on the basis of customer cost benefit.

Q. What significance do LNG levelized costs have in analyzing economic benefits?

A. The Company evaluated its resource options using levelized cost, which is an equivalent annual cost for a resource option, factoring in all capital and operating expenses and the time value of money.

Q. What implications do higher-than-expected construction costs have for levelized costs of the LNG facility?

A. Construction cost increases produce commensurate increases in other key components of the levelized cost. These components include Allowance for Funds Used During Construction (AFUDC), Depreciation Expense, Property Taxes, Property Insurance, Interest Expense, Return Requirement, and Income Taxes. O&M Expenses would be unaffected. We tested the impact that varying construction cost levels would have on levelized project costs using the Company's financial model provided in response to Confidential Data Request PLAN 8-10. To do this, we adjusted the spending (construction draw-down) in $10 million increments, spreading these funds over the construction years in the same proportion as the Company's current plan.

Our testing using the Company's financial model determined that every $10 million increase in LNG construction costs results in an annual levelized cost increase of [redacted]. Accordingly, even a small percentage increase in LNG construction costs, compared to the current Company estimate, would more than eliminate the very small economic benefits management has quantified. Large overruns could be far worse.

Q. What do you understand to be the nature of the Company's observation about LNG facility value, had it been available in the past?

A. We understand the Company to conclude that, had the LNG facility been in service for the five December-through-February winter periods beginning with 2013-14, it would have produced substantial economic benefits to its customers. The Company appears to find these benefits driven primarily by commodity-cost savings achieved by displacing local December-through-February gas purchases with LNG produced from gas bought during the previous summer. It presents support for its belief in two ways, as discussed below.

Q. What is your view of the accuracy of the Company's calculations?

A. The calculations do not support the Company's conclusion, because the logic and execution of both calculations contain material flaws.

First, the Company posits that savings from displacing just baseload city-gate purchases (*i.e.*, just a portion of <u>all</u> local purchases) nearly covers the cost of the LNG facility when added to the Customer Benefit Guarantee and to savings from terminating certain firm transportation capacity contracts. The calculation seeks to show what customers would have saved had EnergyNorth been able to substitute December-through-February gas purchases at Dracut or its city-gates with 2,070,000 Dth of summer gas that the LNG facility could have provided.

See the savings referenced at pages 63 to 65 (Bates Pages 067-069) of the Supplemental Direct Testimony of Francisco D. DaFonte and William R. Killeen.[24]

The Company's estimates[25] show [redacted] benefits totaling [redacted] million, consisting of:

- Baseload commodity-purchase savings of [redacted] million
- Customer Benefit Guarantee totals of [redacted] million ([redacted] million per year)
- Capacity-contract savings of [redacted] million ([redacted] million per year).

This reported [redacted] million compares to a facility cost of [redacted] million ([redacted] million per year in levelized cost). Thus, the LNG facility would produce net costs, not benefits, when considering only the commodity-cost savings from baseload purchases. Customers would, on this basis be down [redacted] million -- not ahead -- had the Granite Bridge LNG Facility operated in the years modeled by the Company.[26]

A significant error arose in the Company's calculation of the volume of gas purchases that the LNG facility could have displaced. The Company's hypothetical used actual baseload city-gate volumes purchased in each year of the five-year periods. These volumes amounted to approximately 1.4 million Dth. However, the Company could not have displaced this much purchase volume with LNG -- management's calculations did not properly account for an assumed contractual arrangement allocating [redacted] Dth of the 2.07 million Dth

[24] Filed on March 15, 2019 in Docket No. DG 17-198. The calculation of the savings is in Exhibit FCD/WRK-8, attached to the testimony.
[25] Excel workbook; Confidential Attachment OCA TS 1-3.b. The Company has deemed this file confidential, and thus it is not included as an attachment.
[26] Confidential Attachment OCA TS 1-3.b, Column J, Row 30.

capacity to a third party.[27] The Company's analysis included the revenues produced by this use of the [redacted] Dth, but only [redacted] Dth, after that [redacted] Dth, would remain available for using stored LNG to substitute for winter-period purchases, rather than the approximately 1.4 million Dth in the Company's calculation.

Reducing available volumes under the Company's hypothetical reduces the commodity-purchase savings from the [redacted] million the Company's analysis calculated to [redacted] million. This, in turn, increases the negative economic impact of the cost of the LNG facility in the historical period management selected from [redacted] million to [redacted] million.

Q. Please describe the second approach that the Company used to demonstrate the benefits of the Granite Bridge LNG Facility.

A. Using generally the same model,[28] the Company added to its baseload city-gate buys other forms of local purchases. This second hypothetical added to baseload city-gate purchase transactions such as call options and spot-market purchases. The second hypothetical used the same December-to-February periods of the same five winters (2013-14 through 2017-18).

Q. What do you conclude about this second hypothetical explored by the Company?

A. It incorporates the same error as the first did, but the magnitude of the error became much higher, because of the vastly greater volumes displaced in the second analysis. The second

[27] Information regarding the MOU was provided in an updated response to DR PLAN 2-6. Attachment PLAN 2-6.1 provides some background information, an overview and a description of its benefits. Attachment PLAN 2-6.2 is the text of the MOU.

[28] Confidential Attachment OCA TS 1-3.b

hypothetical used the entire 2,070,000 Dth capacity of the LNG tank to compute savings. Use of the entire capacity of the facility to store gas for system-supply customers would leave no capacity available for optimization. The second hypothetical also began by taking credit for the Customer Benefit Guarantee revenues. Reducing the amount of stored LNG by the same [redacted] Dth "used twice" in the first hypothetical reduces the calculated savings to customers from [redacted] million to just [redacted] million, virtually eliminating any net benefit that the retrospective analysis produced.

Q. Do you have any additional concerns about the Company's calculations?

A. Yes. Both of the Company's calculations assume that the entire 2,070,000 Dth would have been available for the two purposes:

1. To store gas purchased and liquefied over the summer before the five winter periods used for the calculations, and
2. To offer [redacted] Dth for optimization in order to produce revenues to support the Customer Benefit Guarantee.

In fact, an LNG tank cannot be emptied completely. A small amount must be left in the tank to prevent warming. This amount would have to be deducted from the capacity available for the two purposes. Thus, counting the full 2,070,000 Dth overstates the potential benefit from them.

Q. How would you propose to correct the Company's calculation?

A. We would not. It does contain material calculation errors, but correcting it mathematically would still render it inapt. Correct numbers would still leave a comparison that sheds no meaningful light on an examination of the costs and benefits that the Granite Bridge would bring for customers across many decades.

Q. Please summarize your overall conclusion about the Company's use of historical data to judge the economics of the Granite Bridge LNG Facility.

A. Even if historical analysis were valid here, which is not the case, the results that management produced undermine, rather than support the economics of the LNG facility. When corrected for clear error, even a best-case for the LNG facility produced either negative economic results (harm) to customers, or, at best, razor-thin benefits, depending on which of management's two approaches one favors.

Investments are judged on forecasts and expectations about future needs and markets. This retreat into a self-selected historical cocoon, even apart from the error it introduces or the magnitude of the savings it generates, is no more helpful than a similar retreat to a time period selected to prove the opposite.

Q. Describe your view of the risks that customers bear with respect to forecasts of future requirements.

A. Commitment to the LNG facility would involve considerable risk to system-supply customers. The risk that projected load additions will not materialize is among the most prominent. EnergyNorth has employed total costs over 20 years as a metric for comparing alternatives. At currently-estimated facility costs, and including the Customer Benefit Guarantee offered for the first [redacted] of facility operation, the 20-year metric favors the LNG facility by less than one percent[29] over a no-LNG alternative that retains the propane facilities.[30] That comparison turns negative if the Sales & Marketing Adjustment to forecasted customer growth is removed.[31]

If EnergyNorth adds load only at the econometrically-forecasted rate, rather than at the faster rate forecast by its Sales & Marketing Department, its customers would be worse off economically with the LNG facility than under alternatives, such as: (a) retention of the propane facilities, (b) renewal of the Constellation supply, and (c) obtaining the balance of requirements from Repsol.[32] Thus, with the LNG facility, EnergyNorth's capacity-assigned and supply-service customers would be exposed to far greater economic harm if load additions are lower than currently forecasted. That diseconomy would become all the more adverse with increased capital costs to place the facility into operation.

Customer migration presents another risk source. The Capacity-Exempt customer class comprised about 11 percent of the Company's throughput in 2018.[33] That class pays no

---

[29] ($2,820,168,000 (Exh. FCD/WRK-4) - $2,796,648,000 (Exh. FCD/WRK-2))/$2,820,168 = 0.008. See Table 2 on page 52 (Bates Page 056) in March 15, 2019 DaFonte-Killeen Supplemental Direct Testimony.
[30] Referred to as "Alternative Case Sensitivity Supplemental" in March 15, 2019 DaFonte-Killeen Supplemental Direct Testimony. See page 52 (Bates Page 056).
[31] ($2,498,061,000 – $2,535,390,000)/$2,535,390,000 = -0.015. See cases OCA 12-18.b.1 and OCA 12-18.b.2..
[32] This is "Alternative Case Sensitivity Supplemental," Confidential Exhibit FCD/WRK-4 from the Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen. It is compared to the Company's preferred case, "Base Case Supplemental – Customer Benefit Guarantee", Confidential Exhibit FCD/WRK-2 in Table 2 at 52 (Bates Page 056) of the referenced Supplemental Direct Testimony.
[33] Source: Annual Report of Liberty Utilities (EnergyNorth Natural Gas) Corp. to the Public Utilities Commission of the State of New Hampshire for the Year Ended December 31, 2018, at 30-32.

supply costs. To the extent that increased gas-supply costs cause large-volume customers to avoid the system-supply and capacity-assigned classes, remaining system-supply and capacity-assigned customers would pay more.

Q. Please describe your views of the Company's proposed "Customer Benefit Guarantee."

A. The Company has cited the ability to place any capacity not required by its customers into secondary markets ("optimizing" capacity) as mitigating revenue requirements associated with the Granite Bridge LNG facility. The Company offers a Customer Benefit Guarantee, whose effect is to eliminate charges to on-system customers for [redacted] of the facility's costs for each of the [redacted] of its operation, totaling [redacted].

While forming a source of cost mitigation, the guarantee covers only [redacted] of an expected annual $29.4 million[34] in such costs, and for only [redacted]. We do not consider that amount sufficiently material to address the economic risk to customers over the 21 years of the forecast period or the additional decades of the LNG facility's economic life, during which customers would be responsible for facility costs.

Q. How do you view the distribution of risk and reward in the Company's proposal?

A. The Company's proposed distribution of risk and reward skews heavily toward Liberty Utilities, which will earn returns whether or not its cost estimates (albeit presumably subject to prudence review) or its growth forecasts prove accurate. Customers take installation cost

[34] Source: Confidential Attachment OCA TS 1-3.b.

and growth risk, in return for barely positive benefits even if those estimates and forecasts prove accurate.

Customers might receive a benefit of [redacted] million[35] in levelized costs, spread out over 20 years under those circumstances. That "return" for customers is far too low, uncertain, and subject to reversal to justify obliging them to carry the costs of an investment of some $260.5 million. In stark contrast, the Company's calculations show it receiving cumulative Net Income of [redacted] over the same period.[36] Moreover, the very same cost growth that threatens even the marginal Company-forecasted customer economic benefits, further benefits the Company through higher returns recovered through customer rates.

Q. What is your view of the balance of risks and rewards with respect to the Granite Bridge Pipeline?

A. The Company's analysis suggests that customers would save approximately $51 million in reduced TGP charges[37] over the forecast period. At the current cost estimates, the Company would receive approximately [redacted] in Net Income over the forecast period.[38] Again, customers would bear the risk of reduced load growth and increased costs, but those risks would be spread over all customers, rather than just Sales and Non-Exempt Transportation

---

[35] Source: Confidential Exhibits FCD/WRK-4 minus FCD/WRK-2 from Table 2 at page 52 (Bates page 056) of the Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen, filed in this proceeding on March 15, 2019.
[36] Source: Confidential Attachment PLAN 8-10, Granite Bridge LNG (2.0 Bcf) tab. The indicated amount is the sum of Line 85 from 2023 (Column B) through 2039 (Column R). The Company has deemed this file confidential, and thus it is not included as an attachment.
[37] Source: Attachment Staff TS 10-1, Column F minus Column H
[38] Source: Confidential Attachment PLAN 8-10, Granite Bridge Pipeline tab. The indicated amount is the sum of Line 86 from 2023 (Column B) through 2039 (Column R). Note that the number is a little low because the pipeline would be scheduled to enter service before 2023.

customers. The Company's income stream would last until well after the forecast period, but the benefits of the pipeline would be similarly long-lived.

Q. How do you view the connection between the Granite Bridge LNG Facility and the sizing of the Granite Bridge Pipeline?

A. The Granite Bridge Pipeline appears sized to support operation of the proposed Granite Bridge LNG Facility, rather than optimized to meet the needs of EnergyNorth's customers. As currently configured and costed, the Granite Bridge Pipeline has a throughput capacity of about 200,000 Dth/day.[39] As previously noted, EnergyNorth's current peak-day capacity requirements are 164,571 Dth/day, and are forecast to increase to 225,306 Dth/day by 2038/39.

The Company has stated that it:

> *… wanted to ensure that the proposed Granite Bridge Pipeline was sized appropriately so that it could meet its customers' long-term capacity requirements at the least possible cost.*[40]

It would seem clear, however, that the pipeline as proposed would provide capacity that is well in excess of EnergyNorth's utility-service customers' long-term requirements. Legacy pipeline and storage capacity amounts to 57,833 Dth/day. The Company's LNG-based peaking resources can deliver 12,600 Dth/day. Therefore, even assuming that the Company were to: (a) relinquish its Dracut 20 and Dracut 30 contracts, (b) retire its propane-based peaking facilities, and (c) not renew its Constellation contract, adding the Granite Bridge

[39] The Company's response to DR OCA 1-8 gives the capacity of the proposed pipeline as 149,000 Mcf/day. The response to PLAN 8-5 says the capacity would be "approximately 203,000 Mcf per day".
[40] *Ibid.*

Pipeline would provide 120 percent of the capacity that the Company is forecasted to need 20 years from now.[41] That much capacity is clearly not required for serving utility-service customers.

Q. How may Granite Bridge Pipeline sizing be affected by eliminating the proposed Granite Bridge LNG facility at the present time?

A. The Company has stated that the cost of 12-inch pipe is only $3.3 million less than the cost of 16-inch pipe; *i.e.*, only 1.8 percent of the total proposed cost of the pipeline as currently estimated. [42] We consider it appropriate to consider the "marginality" of added costs into sizing a facility like the Granite Bridge Pipeline. However, we believe that, with the Granite Bridge LNG Facility eliminated, it would be appropriate for the Company to study more carefully the optimum design and cost structure of a pipeline sized without reference to the LNG facility. Should there be a case for preserving extra capacity for a future option for a storage facility such as the proposed Granite Bridge LNG Facility, it would be appropriate to evaluate that optionality, its impacts on current costs, and whether the value of the option would justify the increase in costs.

Q. Why particularly do you recommend further study of Granite Bridge Pipeline optimization?

A. We see a need for added capacity. We consider the Concord Lateral an alternative to the Granite Bridge Pipeline. However, we do not think that alternative has been seriously explored by the Company. It should be, and promptly. Development of more data and

[41] (57,833 + 12,600 +200,000 = 270,433)/225,306 = 1.20
[42] 12 inches in diameter, rather than 16 inches in the Company's proposals. See the Company's response to DR PLAN 8-4, dated April 19, 2019.

analysis about both the Granite Bridge Pipeline and the Concord Lateral alternatives is necessary to permit a fully-informed decision between them.

In examining additional gas-supply capacity to serve growth on its system, the Company has generally looked for an additional connection to the interstate pipeline system. Its objectives have been twofold:

- Increased reliability, accomplished by reducing its dependence on the Concord Lateral
- Moving the receipt point for a large share of its gas supply to points upstream of Dracut, MA.

The last two increments of the Company's gas-supply capacity[43] have used Dracut as their receipt point. Dracut now comprises almost 44 percent[44] of the Company's off-system supplies. The Company is concerned about the level of dependence on that receipt point, as pricing at that point tends to be both high and volatile.

Liberty Utilities considers expansion of the Concord Lateral as a less desirable alternative. However, in our view, the analyses leading to that conclusion have not been sufficiently comprehensive. Moreover, as is true of management's estimates of LNG facility costs, costs for its preferred alternative, the Granite Bridge Pipeline, have also dramatically increased. Mr. Lyon's December 22, 2017 testimony placed estimated Granite Bridge Pipeline costs at \$110 million. They have increased since by 53 percent, based on the Company's more recent

---

[43] This is the Dracut 20 and Dracut 30 contracts, entered in 2001 and 2009, respectively.
[44] 50,000/(107,833 + 7,000) = 0.435

estimate of $167.7 million.[45] This estimate remains based on a fairly low level of preliminary engineering, specifically, the 30 percent minimum required by the New Hampshire Department of Transportation for a Preliminary Conceptual Feasibility Study.

Q. In what ways do you consider management's analysis of Concord Lateral expansion insufficiently comprehensive?

A. Based on the record, the circumstances surrounding Liberty Utilities' discussions and leading to its conclusions about expansion costs do not indicate that management gave the pipeline owner a basis for believing that it faced a serious counterparty. Moreover, management does not appear to have given substantial consideration to phased expansion of the Concord Lateral. A phased expansion, matched to Liberty Utilities' needs as and to the extent those needs continue to grow, appears to comprise a logical alternative. This approach, if otherwise sound and economical, could mitigate the risk that a single, larger expansion would eventually prove excessive, should demands not continue to grow at projected levels.

At most, the information secured so far by the Company is far too preliminary for making a choice between the Concord Lateral and the Granite Bridge Pipeline as one-to-one alternatives.

Q. What basis do you have for concern about the pipeline owner's sense of materiality in responding to Liberty Utilities' inquiries and discussions about Concord Lateral expansion?

[45] Source: Attachment Staff 7-1. Allowance for Funds Used During Construction (AFUDC) would bring this amount to $179.0 million.

A. The Company made clear to TGP that its need for information was in case the NH PUC ruled against the Company's preferred option.[46] That context indicates more a request for information to support a decision already made, not to support one yet to come following detailed data gathering, analysis, and reflection.

Q. Whether reliable or not, what information did the Company's efforts secure?

A. Note, for example, the Concord Lateral expansion presented as an alternative to the Granite Bridge Pipeline. That expansion would amount to 75,000 Dth/day -- a close to 50 percent increase above the Company's current peak-day requirements (164,571Dth/day).

Discussion leading to this alternative[47] began soon after TGP abandoned the Northeast Energy Direct (NED) Project. EnergyNorth had contracted for 115,000 Dth/day of capacity on that project - - 50,000 Dth/day to move the receipt points for the Dracut 20 and Dracut 30 contracts upstream, and 65,000 Dth/day of new capacity. Neither of these additions would have required expansion of the Concord Lateral. The Dracut 20 and Dracut 30 contracts would have provided the capacity to move the 50,000 Dth/day from Dracut to the Company's city gates. The new capacity would have delivered to a new interconnect with the new pipeline, to be located in Merrimack, NH.

Liberty Utilities first requested that TGP provide estimates for two alternatives:

---

[46] These conversations occurred through e-mail exchanges, perhaps elaborated through telephone calls. A record of the e-mail exchanges was provided in response to a data request from the Office of the Consumer Advocate. See Attachment OCA 2-46 , at 1-2 to the Company's response to DR OCA 2-46.
[47] *Ibid.* See pages 1-2.

- One for moving the receipt point for part of the existing capacity to TGP's interconnection with the Everett LNG receiving terminal, and adding 25,000 Dth/day to receipts at Dracut
- A second for an increase of 50,000 Dth/day delivered to Dracut.

The first of those alternatives would have required an increase of 25,000 Dth/day to the capacity of the Concord Lateral, the second an increase of 50,000 Dth/day.

Indicative costs[48] provided by TGP to EnergyNorth turned out to be comparatively very high for both alternatives. The capital costs for the all-Dracut alternative were estimated at [redacted], and those for the Everett-and-Dracut alternative were [redacted]. [redacted].

Liberty Utilities waited about six months, then asked TGP for facilities costs and indicative rates for a 75,000 Dth/day expansion of the Concord Lateral. Management appears not to have [redacted], either then or in the interim.

[48] Attachment OCA 2-46. See page 13.

Q. What is your view of the Company's observation that the Granite Bridge Pipeline would produce benefits by eliminating dependence on a single connection to the interstate pipeline system?

A. Multiple connections theoretically produce benefits, but they need to be placed into context. First, we understand that the Concord Lateral has performed for nearly 70 years without incident. We have experience with or knowledge about other gas distribution systems that rely on single sources as well. Management has cited to us a single incident affecting the National Grid system in Rhode Island last winter as illustrating the risk associated with dependence on a single feed to a lateral.[49] No supporting data permits a conclusion, or even an inference, that the causes of that incident have relevance to circumstances here, or even to fears of recurrence of such an event in Rhode Island.

There appears to be no dispute about the observation that the Concord Lateral has had a long, sound performance history. Particularly given that history, it is difficult to see how citing a problem in Rhode Island, as yet unconnected to the circumstances in New Hampshire, bears on spending very large sums to back up the capability it provides to EnergyNorth in New Hampshire. From a planning perspective, it would appear the Company agrees. It has provided no analysis of the costs relative to the reliability benefits of providing a second supply source.

The same conclusion applies to pricing benefits. While interesting theoretically, there is again no analysis, claim, or quantification of lower gas costs resulting from access to a

[49] See, *e.g.*, https://patch.com/rhode-island/newport/national-grid-gas-outage-affects-over-7-000-newport

greater number of suppliers than those already available through the Concord Lateral. If any such support does exist, the more robust study we recommend of the Granite Bridge Pipeline and Concord Lateral expansion would provide an opportunity to explore them specifically, carefully, and more meaningfully.

Other gas distribution companies, in our experience, operate service territory sectors served from single connections to an interstate pipeline system. While all might prefer multiple connections to gas sources, economic considerations and the configurations of service territories and pipeline systems sometimes preclude them. The more central question is the cost at which multiple connections would come, compared with the anticipated benefits produced.

Q. What is your view about pricing and availability of supply at Dracut?

A. Other market participants address the problem of volatile pricing at New England market-area locations through contracting strategies, such as specifying pricing at other locations in their requests for proposals for gas supplies. Other possibilities, such as the Company's attempt in the NED project to move the receipt points upstream for some of its supplies, remain to be explored. This problem is not sufficient justification for abandoning expansion of the Concord Lateral as an option.

Q. What do you recommend with respect to comparing the Granite Bridge Pipeline proposal with expansion of the Concord Lateral as an alternative?

A. We recommend a careful comparison of incremental expansion of the Concord Lateral sized to support load, if and as it may grow, with the Company's proposed Granite Bridge Pipeline. That comparison should provide more detailed analysis of the costs of various sizes, equipment configurations, and optionality for the Granite Bridge Pipeline.

Both alternatives have advantages and disadvantages. With respect to ***capacity costs***, unit capacity costs for the new pipeline would likely be lower, but capacity could not be added incrementally; its full length would require construction at once. Thus, customers would be exposed to the risk that some of the installed capacity might not be needed for a long time, or might never be needed. Some cost could be deferred by constructing a smaller-diameter pipeline initially, then adding capacity later, using compression or looping. On the other hand, adding a connection to two other pipeline systems[50] could give bargaining leverage over TGP and its other upstream pipeline resources that could result in lowering the costs of those resources, or even eliminating some of them. In particular, the Company has observed that, with the Granite Bridge Pipeline, it could switch to Interruptible Transportation or Authorized Overrun service for volumes purchased at Dracut, allowing it to terminate the Dracut 20 and Dracut 30 contracts. That change would save $5.5 million per year in fixed costs.[51]

[50] The Joint Facilities, to which the Granite Bridge Pipeline would be connected, in turn connects to the Portland Natural Gas Transportation System and the Maritimes & Northeast Pipeline System. Those two pipelines own the Joint Facilities.
[51] See the response to DR Staff TS 10-1.

With respect to ***reliability***, we are not persuaded that a second feed is necessary to avoid service interruptions such as the one experienced last winter by some of National Grid's Rhode Island customers. Nevertheless, we acknowledge that connection to a second pipeline would bring additional reliability, perhaps marginally reducing the risk of service interruption from very small to very, very small (subject to further study and analysis by the Company).

Management has stated that delivery pressures to its gate stations can decline to relatively low levels at times of high demand. Adding the Granite Bridge Pipeline would support higher delivery pressures at the Company's Concord Lateral gate stations downstream of Manchester.

With respect to ***extending service***, if the Granite Bridge Pipeline secures approval, the Company proposes to extend natural gas service along the route of the pipeline to communities that currently do not have access to service. Perhaps this extension is not feasible from the Concord Lateral, or is only feasible at costs that are prohibitive. The Company should present a careful comparison of the alternatives on this point.

Finally, in terms of ***customer impact***. The Company reports that its approved distribution rate base as of December 31, 2016 totaled $244,389,428.[52] The Granite Bridge Pipeline is estimated to cost $178,957,376, including AFUDC.[53] Adding the pipeline as part of the

[52] Source: Response to DR Staff 9-1.
[53] Source: Attachment Staff 7-1

distribution system would increase rate base by about 73 percent.[54] Adding the estimated cost of the Granite Bridge pipeline to the December 31, 2016 rate base increases the return requirement by $12.2 million, from $16.6 million to $28.8 million.[55] As a system cost, that increase would be spread among the various customer classes according to the Company's rate design.

Increased costs resulting from adding the Granite Bridge LNG tank would be recovered through cost-of-gas rates. Those costs would fall disproportionately onto Firm Sales customers. Non-exempt Transportation customers would share in any cost increase, but Capacity-Exempt Transportation customers would escape any increase. Details of the impacts would be left to rate design, but, as identified in the earlier discussion of the LNG facility, the ability to avoid this cost might serve as an incentive for new customers to choose Capacity-Exempt service.

The Company should develop comparisons, on these characteristics and any others that should be considered, and present them for examination such as that allowed in this proceeding. The comparisons should include a full examination of rate impacts of the alternatives.

The Propane-Based Peaking Plants

Q. What is the Company recommending regarding its propane-based peaking plants?

[54] $178,957,376/$244,389,428 = 0.732
[55] Calculated using the Computation of Revenue Requirement in Order No. 26,122, Appendix 1, Page 1 of 16.

A. The Company's intentions regarding its propane-based peaking plants are not fully clear. As noted earlier, it recommends replacing them in its LCIRP filing.[56] In this proceeding, however, Company Witnesses Fleck and DaFonte[57] and Killeen and Stephens[58] refer to an "option" regarding the retirement of the existing propane facilities. Witnesses Fleck and DaFonte speak of "retir[ing] the aging propane facilities should that be determined to be in the best interest of our customers."[59]

Q. Do you consider the propane-based peaking plants valuable assets?

A. Yes. The propane plants provide reserve supplies at very competitive cost at times when other supplies would be very costly, let alone potentially not available at all.

Q. How much does the Company use the propane plants?

A. The table below shows the number of days in the five winters 2013-14 through 2017-18 on which it dispatched at least some propane[60]. Our understanding is that capacity-exempt customers were part of the load on all of these days.

[56] LCIRP at 48, in Docket No. DG 17-152.
[57] Direct Testimony of Susan L. Fleck and Francisco C. DaFonte, filed on December 21, 2017, in Docket No. DG 17-198, at 17 (Bates Page 021).
[58] See, *e.g.*, Direct Testimony of William R. Killeen and James M. Stephens, filed on December 21, 2017, in Docket No. DG 17-198, at 82 (Bates Page 194).
[59] Fleck and DaFonte, *Op. cit.*, at 17 (Bates Page 021).
[60] Response to DR Staff 4-3.

	Total Number of Days Dispatched	**Number of Days w/ Small (< 1,000 Dth) Dispatch**	**Maximum Dth Dispatched**	**Date of Maximum Dispatch**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The Company reported only four days within the last six years during which all three of the Company's propane facilities operated on the same day, and no days in the last six years when the Company used the entire capacity of all of them for 24 hours.[61]

The winter season covers a period of 151 (or 152) days. Full capacity of the propane plants is 34,600 Dth/day. In that context, we would say that the propane facilities are not used extensively, but appear quite valuable when used.

Q. Are there other aspects that give the propane facilities value?

A. Yes. The storage at the propane plants is helpful in enabling the Company to satisfy PUC Rule 506.03, which requires the Company to maintain sufficient upstream and on-system supplies to satisfy the coldest seven-day period on record. Moreover, we understand that the propane plants are "grandfathered" with respect to the current Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations, and the current safety codes under the National Fire Protection Association standards. Any effort to modify those facilities would likely result in loss of that status, resulting in loss of supply capacity at important points within the Company's distribution system.

[61] Response to DR OCA TS 1-1. The Company has deemed this file confidential, and thus it is not included as an attachment.

Q. What about the Company's concern about the impact of propane on its service quality?

A. The impact of the propane-air blend on high-efficiency heating equipment does raise material concern. The benefit of the propane facilities for the majority of the Company's customers, however, calls for a more comprehensive analysis of the options for resolving that concern before concluding that replacing the propane facilities with a costly new LNG facility is preferred.

Q. What is your view of the reliability of the propane facilities or the costs of maintaining them, given their age?

A. As a general matter, we find no evidence to suggest that well-maintained propane-air plants are unreliable, even if 50 years old like some of EnergyNorth's. We asked the Company for:

- Maintenance activities scheduled and performed for each of the past five years
- O&M and capital expenditures for the last five years
- O&M and capital budgets this year and next year
- O&M and capital expense forecasts for as many years as are available
- Performance data compiled against metrics used by management to assess the condition, availability, reliability or other performance characteristics of each plant
- Condition assessments, remaining life analyses, and any other reports addressing the physical condition of each of the plants.

The Company provided records of monthly and annual inspections,[62] which showed no unusual problems. Management reported that discussions with operators revealed difficulties in starting air compressors in Manchester on three days during the most recent winter, and in Nashua on one day. The problem equipment was identified as *rental* air compressors, with no additional information regarding why the equipment was rented, or how the problem is being addressed.[63]

The following shows Company data on recent capital expenditures on the propane plants.[64]

2014	2015	2016	2017	2018
$108,000	$15,000	$61,000	$25,000	$150,000

The next table summaries recent O&M expense.[65]

2013	2014	2015	2016	2017	2018
$213,174	$47,452	$270,140	$451,236	$466,522	$401,193

A Company accounting change between 2016 and 2017 had the effect of including 60 percent of 2017 expenditures and 83 percent of 2018 expenditures in cost codes that do not appear prior to 2017. Thus, much of the values in those years appear to reflect accounting changes, rather than real increases in expenditures. That does leave a material increase in 2016, but that increase arose in several labor accounts whose amounts dropped off subsequently. It appears, for reasons not apparent to us, that the Company began including operating personnel costs first in 2017. These personnel costs totaled $270,149 in 2017 and

[62] Response to DR Staff TS 10-2.a.
[63] Response to DR Staff TS 10-4.
[64] Source: Attachment Staff 10-2.c.
[65] Source: Attachment Staff TS 10-2.d

$333,234 in 2018. Excluding them would change recent O&M expenses by year to the following:

2013	2014	2015	2016	2017	2018
$213,174	$47,452	$270,140	$451,236	$196,373	$67,959

We inferred from responses to our requests about cost information that EnergyNorth has no budget for propane facility capital costs for the next several years.[66] Nor has it developed performance or reliability metrics for them.[67] It has commissioned no studies or assessments of propane-plant conditions or life expectancies.[68] In our experience, careful attention to possible retirement decisions has been accompanied by oversight in a manner not seen at EnergyNorth -- such as through forecasts of capital and operating costs, performance trending using measures, and condition assessments. The Company has not established that retiring the propane facilities on the basis of not being reliable is appropriate.

Q. What is your recommendation regarding the Company's propane facilities?

A. As noted earlier, we believe that the propane plants comprise valuable assets. We recommend that the Company develop a strategy for dealing with any service-quality issues that they present, and that it take strong and proactive measure to maintain them, so that they can be relied on without hesitation.

Q. Does this complete your testimony?

A. Yes, it does.

[66] Response to DR Staff TS 10-3.
[67] Response to DR Staff TS 10-4.
[68] Response to DR Staff TS 10-5.