REDACTED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 20-105

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

DIRECT TESTIMONY

OF

WILLIAM J. CLARK

AND

MARK R. STEVENS

July 31, 2020

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS

THIS PAGE INTENTIONALLY LEFT BLANK

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full names, positions, and business addresses.

A. (WC) My name is William J. Clark and I am the Senior Director, Business Development. My business address is 116 North Main Street, Concord, New Hampshire.

(MS) My name is Mark R. Stevens and I am a Business Development Professional. My business address is 116 North Main Street, Concord, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("Liberty"), which provides services to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or "the Company") along with other regulated utility affiliates, including Granite State Electric.

Q. Please describe your educational and professional background.

A. (WC) I graduated from St. Anselm College in Goffstown, New Hampshire, with a Bachelor of Science degree in Financial Economics in 1991. I have twenty-five years of experience in the natural gas and electric utility industries with roles in Operations, Sales, Marketing, and Business Development. I joined Liberty in 2012 as a Key Account Manager and progressed into my current position as Senior Director, Business Development East Region. In this role I am responsible for strategic investment opportunities including acquisitions, emerging technologies and organic growth.

(MS) I graduated from Saint Anselm College in Goffstown, New Hampshire, with a Bachelor of Science degree in Business in 2000. I have approximately five years of experience in the natural gas utility industry with roles in Sales and Business Development. I joined Liberty in July 2015 as a Sales Account Manager and have been in my current position as a Business Development Professional since January 2019. In my current role I am responsible for strategic growth and expansion opportunities for both EnergyNorth and Granite State Electric.

Q. Have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission?

A. (WC) Yes, I have previously testified before the New Hampshire Public Utilities Commission (the "Commission") with respect to EnergyNorth's various growth initiatives such as the Managed Expansion Program (Docket No. DG 16-447), the Windham and Pelham Franchise Expansion (Docket No. DG 15-362), the Liberty Utilities and Concord Steam Joint Petition for Approval of an Asset Purchase Agreement (Docket No. DG-16-770), and the Company's special contract with the New Hampshire Department of Administrative Services ("NHDAS") (Docket No. DG 17-035).

(MS) No, I have not previously testified before the Commission.

Q. What is the purpose of your testimony?

A. Our testimony provides status updates regarding two special contracts approved by the Commission in Docket Nos. DG 14-091 and DG 17-035, including information in support of the Company's request for recovery of certain costs associated with these contracts that are not already being recovered through rates.

In Docket No. DG 14-091 the Commission approved a lease and special contract between EnergyNorth and Innovative Natural Gas ("iNATGAS") related to the construction of a compressed natural gas ("CNG") facility on Company-owned property.[1] The iNATGAS contract is discussed in more detail in Section II of our testimony.

In Docket No. DG 17-035, the Commission approved a special contract between EnergyNorth and the NHDAS for temporary gas boiler installation at certain state office buildings in Concord, New Hampshire.[2] The NHDAS contract is discussed in more detail in Section III of our testimony.

II. iNATGAS SPECIAL CONTRACT UPDATE

Q. Please describe the iNATGAS Special Contract.

A. In Docket No. DG 14-091, EnergyNorth filed a petition for approval of a special contract and lease agreement with iNATGAS related to construction of a CNG facility.

In order to facilitate the transaction with iNATGAS, EnergyNorth agreed to lease land to iNATGAS for locating the CNG fueling station. Pursuant to the terms of the lease agreement, iNATGAS agreed to pay rent to EnergyNorth during the term of the lease. The lease agreement also outlined the construction obligations of iNATGAS and EnergyNorth. iNATGAS was required, at its sole expense, to construct a CNG fueling station facility. EnergyNorth was required to undertake certain obligations in support of the CNG facility supported by financial considerations outlined in the special contract,

1 See Orders No. 25,694 (July 15, 2014) and No. 26,002 (Apr. 16, 2017).

2 See Order No. 26,018 (May 15, 2017).

including: (1) construct the compressor station; (2) conduct all site work and site preparation; (3) extend a transmission grade natural gas service line to the compressor station; (4) provide a 1250 KVA 3-phase step-down transformer and related electrical connections; (5) install gas conditioner equipment and up to six electric motor-driven compressors; (6) pay the property taxes and costs of snow removal at the compressor station and CNG fueling station; and (7) prepare and submit all necessary permitting with the City of Concord and State of New Hampshire.

The special contract outlined the terms by which EnergyNorth provides firm transportation of CNG to the iNATGAS CNG fueling station. The special contract runs for a term of 15 years and provided that iNATGAS would be a sales customer of the Company for the first year of the special contract. Under the special contract, iNATGAS pays a fixed delivery charge for all therms metered at the delivery point. This charge will remain in effect for the 15-year term of the special contract and is not subject to adjustment. iNATGAS agreed to pay this charge, which was at the time in excess of the Company's tariff, in order to compensate EnergyNorth and its customers for its construction costs and permitting obligations outlined in the lease.

Q. Please describe the projected sales analysis relied on by the Company for approval of the special contract.

A. iNATGAS provided annual sales volume projections for the facility. Using these projections, EnergyNorth developed a cost analysis that considered the benefits associated with three scenarios: a minimum analysis (based on the volumes required under the take or pay obligation discussed below); a baseline analysis; and an accelerated sales analysis. EnergyNorth estimated that it would incur costs between $1.8 and $2.2 million associated with its construction and permitting obligations associated with the lease and special contract.

Based on the projections provided by iNATGAS and the Company's cost estimates, the Company determined that it would be able to recover its investment in 5.5 years under the minimum revenue projection scenario. The Company's analysis also calculated recovery of the investment in as few as three years and four months under the accelerated projection analysis, using data from iNATGAS. EnergyNorth determined that the project was financially beneficial for the Company and its customers based on this analysis because the 5.5 year recoupment timeline was less than the 6-year revenue test required for similar investments under the Company's tariff at the time. Other benefits associated with the arrangement were projected to occur based on the provision in the special contract that iNATGAS would become a sales customer for at least the first year of the special contract, because this would lead to increased off-peak demand on the Company's system allowing EnergyNorth to spread out its fixed costs across greater volumes and thereby reducing the average unit cost to all sales customers.[3]

3 See Order No. 25,694, at 9.

Q. Did the special contract include any provisions to ensure that these benefits to customers would in fact accrue?

A. Yes. iNATGAS agreed to purchase certain minimum quantities of gas over the 15-year term of the special contract (the "minimum take or pay" obligation). The minimum take or pay obligation was set at 300,000 dekatherms ("Dth") of natural gas per year for the first two years of the special contract term; 500,000 Dth for the third and fourth years of the special contract term; and 1,300,000 Dth per year for the remainder of the special contract term (years five through fifteen).

iNATGAS guaranteed its minimum take or pay obligation through personal and corporate guarantees, and by depositing $1.22 million into an escrow account to be used as a backstop in the event payments were not received from iNATGAS pursuant to the minimum take or pay obligation. This escrow amount represented the net present value of the special contract's minimum take or pay obligation over the first five years of the agreement.

The Commission approved the special contract finding that EnergyNorth's investments were more than offset by the anticipated revenues and were similar to upfront investments in physical plant that the Company has made to serve other large customers.[4] The CNG facility was built and placed into service on December 1, 2016.[5] The

4 Order No. 25,694, at 8–10.

5 The Commission approved certain clarifying amendments in Order No. 26,002 (2017).

Commission's approval of the special contract included review of the Company's cost estimate related to its investment under the terms of the lease.

Q. Did EnergyNorth incur costs in excess of the original estimates to facilitate the project?

A. Yes. As referenced above, EnergyNorth incurred costs that were in excess of the original estimates due to the following factors: (1) the Company determined that it was in the best interest of customers to construct a full capacity facility from the start, instead of limiting construction to the proposed phased approach, based on changed market circumstances (approximately $700,000); (2) the City of Concord imposed additional road construction and paving requirements (approximately $600,000); (3) the Company determined that design changes were necessary to ensure protection of the equipment at the facility (approximately $200,000); (4) the Company incurred increased costs for asphalt and concrete work together with minor design changes (approximately $600,000); and (5) the Company's project estimate included only direct costs and therefore did not account for Allowance for Funds Used During Construction ("AFUDC"), overheads, and burdens associated with the project (approximately $435,000). These incremental costs totaled approximately $2.5 million.

Q. How did the Commission address cost recovery for this project in EnergyNorth's 2017 rate case?

A. The Commission previously considered cost recovery of the Company's investment related to the CNG facility in Docket No. DG 17-048, EnergyNorth's 2017 rate case, and approved recovery of the plant up to $2,296,307 consistent with costs projected in Docket No. DG 14-091, but did not allow inclusion of the incremental costs that were not included in the original estimate.[6] The Commission's order in the 2017 rate case did not preclude recovery of these additional costs, subject to a future determination that the special contract could provide customer benefits.[7] The Company has performed an updated discounted cash flow analysis, discussed below and provided as Attachment WJC/MRS-1, that demonstrates there are positive customer benefits even with the additional costs, and that recovery of the total project costs is thus justified. The Company now seeks approval for recovery of the incremental costs associated with the special contract that were not included in the original approval.

Q. Why did the Company decide to move forward with completion of the full capacity facility instead of adhering to the phased construction plan?

A. The original cost estimate was for a first phase of construction that would not have accommodated the accelerated growth model beginning in years 4 and 5, and therefore these costs would have been necessary later in the contract term under the proposed phased construction plan. The decision to build a "full capacity" facility at the outset (instead of following the original phased construction plan) was made following the 2014/15 winter that included polar vortex conditions. Due to these extreme weather conditions during the 2014/15 winter, spot prices for natural gas soared and oil and

6 The Commission denied recovery of these costs by implementing a downward adjustment to the Company's requested revenue requirement which was based on a one-year analysis of the revenue requirement associated with the actual plant investment as compared to the $2,296,307 of capital costs allowed, rather than based on a multi-year discounted cash flow analysis used to approve the contract.

7 Order No. 26,122, at 31.

propane prices were also extremely high. By proceeding with the full capacity construction, the iNATGAS CNG facility would become the only CNG facility in the Northeast with firm capacity on an interstate pipeline capable of providing customers with a cost-effective alternative to oil, propane, or spot gas. Large CNG providers were also announcing frequent new customers at that time. Based on these conditions, EnergyNorth determined that additional customer benefits would be realized if the facility were built at full capacity from the outset.

In order to enable the benefits associated with a full capacity facility, the Company incurred costs of approximately $700,000 that were incremental to the original project cost estimate. It is important to note that these costs were always going to be incurred in order to facilitate the minimum take or pay obligation volumes starting in year five of the special contract; the Company's decision to move forward with the full capacity build out was a timing decision and should not be viewed as a project cost overrun.[8]

Q. Please explain the additional requirements imposed by the City of Concord and why these costs were not included in the project cost estimate.

A. Increased costs were attributed to new conditions imposed by the City of Concord related to reconstruction and paving on Broken Bridge Road where the facility is located. It was after the Commission's order was issued approving the special contract that EnergyNorth

8 EnergyNorth identified these additional costs related to the full capacity facility needs through discovery in Docket No. DG 14-091. See, e.g., Response to Staff 2-8 in DG 14-091 ("At full build out, the station capacity for thermal/filling applications, will be approximately 2,300,000 dth's per year. To achieve this build out, two additional compressors will be required as well some minor extensions of the canopy at the CNG station. Liberty's expected cost for this would be approximately $600,000-$700,000")

was informed for the first time of these new conditions, which included a requirement by the City to install a new water line from the top of Broken Bridge Road to the driveway of EnergyNorth's LNG facility, to reconstruct and repave the length of Broken Bridge Road from the pet crematorium to the end of the public road, and to construct a public turnaround point. Because there is little traffic on Broken Bridge Road other than EnergyNorth (there is one other business and only two homes), and since EnergyNorth has been using the road for decades (its Concord LNG facility is located there), the Company had no reason to believe the City would require an upgrade of almost the entire road, and installation of water service as part of the iNATGAS project. This incremental work required by the City accounted for approximately $600,000 in mandated costs that were incremental to the original estimate.

Q. Please explain why design changes were necessary.

A. The design changes implemented by EnergyNorth were made to better protect the Company's investment in the facility. These design changes were also made to optimize facility run time, which can enhance distribution revenues. The design changes included housing the compressors and control systems within a full, three-sided building, rather than beneath an open canopy, the construction of roof protections over the meters and regulators, and additional equipment behind the compressor building. Making these design changes ensured that the equipment owned by the Company (an investment in excess of $1.3 million) would be better protected, recognizing that damage to this equipment would be the financial responsibility of the Company. Further, by constructing these protections the Company anticipated more available run time at the facility due to the increased reliability and service associated with protection from weather. The other design changes that resulted in incremental costs were minor.

Q. Please explain the additional costs for asphalt and concrete work.

A. The Company incurred costs of $635,000 for additional asphalt and concrete work. These costs were necessary for timely completion of the project. The actual costs (in response to a competitive request for proposals) were higher than projected, likely due to the fact that the work was done at the end of the construction season when asphalt plants were closing for the winter.

Q. Please explain why the Company did not include known, indirect costs including AFUDC in its original cost estimate for the project?

A. The Company agrees that including these indirect costs would have provided a more complete cost estimate. However, as discussed below, even if these costs had been included it would not have changed EnergyNorth's determination that the investment would provide benefits to customers. The Company has also updated its internal processes to ensure that indirect costs are included in all cost-benefit analyses.

Q. Is the special contract beneficial to customers even with the additional costs?

A. Yes. Even with the additional costs incurred by the Company to complete the facility, the project provides positive benefits to customers based on the minimum take or pay obligations over the term of the contract. The minimum take or pay obligation was specifically included in the special contract to ensure benefits to EnergyNorth's customers. The Company has prepared an updated analysis (discussed below) that sets forth these benefits, which analysis is provided as Attachment WJC/MRS-1 and shows a positive net present value ("NPV"), even if revenues do not exceed the minimum take or pay obligation.

Q. Has the Commission previously reviewed the costs associated with the iNATGAS special contract?

A. Yes. As stated above, the Company sought recovery of its total investment ($4,956,658)9 in its 2017 rate case. The Commission's Order allowed EnergyNorth to recover the plant associated with its investment up to the level of costs presented in Docket No. DG 14-091 of $2,245,000, but did not foreclose recovery of the additional costs upon a showing of customer benefit.10

Q. Did the Commission state a reason why it did not approve the Company's total investment in its 2017 base rate case?

A. The Commission determined that the Company's initial analysis in support of its projected investment amount was incomplete as presented in Docket No. DG 14-091 because the original project costs did not include the incremental costs described above.[11]

---

9 See Attachment WJC/MRS-1. The DCF analysis included in the attachment is provided on the same basis as Exhibit 46 in Docket No. DG 17-048, i.e., the amount used in the analysis is exclusive of burdens which brings the adjusted total to $4,815,594, the amount reflected in the DCF analysis.

10 See Order No. 26,122, at 31.

11 Order No. 26,122 at 28-29.

The Commission also questioned whether the benefit analysis presented in support of the project was reliable if it did not account for the costs associated with construction of the complete facility (instead of just the costs associated with the first phase of the project).[12]

Finally, the Commission raised concerns about when the Company became aware of the increased paving and construction requirements imposed by the City of Concord and the increased costs related to design changes. The Commission stated that if these increased costs were known to EnergyNorth prior to approval of the special contract an updated analysis should have been provided.[13]

These concerns led the Commission to initially approve recovery of only the plant associated with the original cost estimate in the 2017 base rate case.

Q. Has EnergyNorth addressed the Commission's findings in the 2017 base rate case?

A. Yes. The Company has updated its analysis for this project to account for these incremental costs, Attachment WJC/MRS-1. This analysis shows that there are still benefits even with the incremental costs. Further, the additional costs incurred by the Company were prudent and were not known at the time that approval of the special contract was requested (or received). The Company provided cost estimates in its filing based on the best information available at that time. The Company now provides a clear justification for each category of increased costs above. The increased costs for paving and materials account for approximately $1,200,000 of the increased costs and were

12 See Order No. 26,122 at 31.

13 See Order 26,122 at 29.

outside of the Company's control. EnergyNorth was required to comply with the requirements of the City of Concord related to paving and road construction.

Further, it was prudent to incur the additional costs associated with the accelerated buildout. As discussed above, after approval of the special contract there was a change in market conditions. This change in market conditions resulted in increased demand due to very cold weather conditions during the winter of 2014/15 coupled with increased prices. Accelerated and expanded buildout of the facilities was prudent in light of these changed market conditions because by building the complete capacity facility, the Company positioned itself to take advantage of these market conditions for the benefit of its customers.

Q. Is the iNATGAS contract currently providing benefits to customers?

A. Yes. Although the CNG facility has seen low actual volumes and iNATGAS purchases have been below the minimum take or pay obligation, EnergyNorth remains entitled to payments for the full minimum take or pay obligations as outlined in the special contract, and has received such payments. iNATGAS has compensated EnergyNorth through a combination of direct payments and through withdrawals from the escrow account that was established under the terms of the agreement. Further, it is EnergyNorth's understanding that iNATGAS is actively pursuing customers to utilize the CNG compression facilities.

Q. Have you prepared an updated Exhibit 46 from Docket No. DG 17-048, and if so what are the results of that analysis?

A. Yes. Exhibit 46 included an NPV analysis based on the actual EnergyNorth construction costs and overheads of the CNG facility over the 15-year term of the contract under three different revenue scenarios, as well as an NPV analysis using the original estimated project costs. Those three revenue scenarios were (a) receipt of the annual take or pay minimum, (b) a baseline scenario of volumes anticipated at the time of the negotiated special contract, and (c) an accelerated volume scenario under a high oil price scenario. Please see Attachment WJC/MRS-1 for the updated analysis of Exhibit 46. The updated results demonstrate a positive NPV based on the 15-year contract term, using the final, actual construction costs of the facility, and under the contracted minimum take or pay scenario.

Q. Does the special contract contain protections for the Company related to the ability of iNATGAS to make payments as required during the remaining contract term?

A. As detailed above, the Company negotiated, and the Commission approved, several provisions in the special contract that are designed to ensure that EnergyNorth receives payments under the contract and/or that the Company has appropriate recourse options. These protections include the escrow account, corporate guarantees, and forced liquidation of iNATGAS assets. Although the Company does not anticipate a default event by iNATGAS, if such an event were to occur, EnergyNorth would take all appropriate steps to enforce the payment provisions of the special contract for the benefit of its customers.

Q. Does the Company have any additional information relevant to the Commission's prior review of the project costs?

A. Yes. The Commission's order in the 2017 rate case proceeding and the resulting rates relied on an analysis performed by Commission Staff that did not account for the increasing minimum pay or take obligation that is set forth in the special contract. As discussed above, iNATGAS' obligation increases pursuant to a set schedule. Starting in year 5 of the special contract, its obligation increases to 1,300,000 Dth. The analysis relied on in the 2017 rate case used the lower minimum take or pay obligation applicable for years 1 and 2 of the contract, which was only 300,000 Dth, and not the higher minimum obligations in subsequent years. As a result, the rates approved for recovery of the costs associated with this special contract should, at a minimum, be updated to reflect the current minimum take or pay obligation. Without this adjustment, the Company will not be collecting an amount that is consistent with the investment approved by the Commission in Docket No. DG 17-048. In fact, when the take or pay obligation increases under the special contract, the Company will begin over-collecting if an adjustment is not made.

III. NEW HAMPSHIRE DEPARTMENT OF ADMINISTRATIVE SERVICES SPECIAL CONTRACT UPDATE

Q. Please describe the circumstances that led to the special contract with the New Hampshire Department of Administrative Services ("NHDAS') that was the subject of Docket No. DG 17-035.

A. The special contract with NHDAS resulted from the wind down of Concord Steam and the Company's agreement to assist NHDAS in connection with that event. Concord Steam was the utility that provided steam service to a number of state-owned buildings in Concord, New Hampshire. In the fall of 2016, Concord Steam announced that it would go out of business, and the Commission authorized Concord Steam to terminate service as of May 31, 2017.[14] The termination of service by Concord Steam meant that its customers, including NHDAS, had to convert to an alternative heating source over a relatively short period of time.

NHDAS is the agency responsible for managing State-owned buildings, including the buildings that were served by Concord Steam. At the time that the Commission authorized termination of service by Concord Steam, NHDAS lacked sufficient time or budget to convert the impacted buildings to another heating source ahead of the May 31, 2017, termination date. NHDAS thus developed a plan to install temporary steam boilers to heat the impacted state buildings until such time as NHDAS could implement a permanent conversion. NHDAS approached EnergyNorth for assistance with obtaining and financing the temporary boilers. EnergyNorth agreed to assist NHDAS, and the

14 Order No. 25,966 (Nov. 10, 2016).

provisions of the agreement were set forth in the special contract approved in Docket No. DG 17-035.

Q. Why did EnergyNorth enter into this contract?

A. EnergyNorth agreed to the terms of the special contract to assist NHDAS and facilitate Concord Steam's wind down of operations because, absent the special contract, NHDAS (Concord Steam's largest customer) would not have had the ability to heat its buildings. This likely would have jeopardized Concord Steam's termination of service and could have resulted in extraordinarily high rates for NHDAS, if all other Concord Steam customers had converted away from steam and NHDAS was the last Concord Steam customer, solely responsible for all of Concord Steam's costs.

Q. Please describe the basic terms of the contract.

A. The special contract required EnergyNorth to arrange for contractors to design and install the temporary steam boilers, all subject to NHDAS approval. Under the special contract, EnergyNorth was also the party responsible for payment of the contractors subject to later reimbursement from NHDAS. The contractors performed all construction work, EnergyNorth provided natural gas services to the temporary boilers, and the project was managed by NHDAS personnel.

The special contract did not include a set price for the work; instead, the contract contained a "not-to-exceed" price. A not-to-exceed price was necessary because exact costs were unknown at the time that the special contract was executed and NHDAS, as a state agency, is prohibited from entering open-ended time and materials contracts. The exigent circumstances required this approach. The parties agreed to a not-to-exceed amount of $2,725,000, based on contractor estimates. Pursuant to the terms of the contract, NHDAS agreed to repay EnergyNorth for these contractor costs through a surcharge on the monthly utility bills related to the temporary boiler accounts.

Lastly, the special contract contained the following provision that obligated NHDAS to seek additional funds if the actual costs exceeded the not-to-exceed amount: "If the costs that Liberty reasonably incurs … are greater than the not-to-exceed amounts … then NHDAS agrees to take all reasonable steps to obtain the funds necessary to reimburse Liberty, including, but not limited to, seeking Governor and Executive Council approval …."

Q. Did the contractors complete the work by the May 31, 2017 deadline?

A. Yes, the temporary boilers were installed, connected to EnergyNorth's natural gas system and to the existing steam pipes, and in service by May 31, 2017.

Q. How long did the temporary boilers provide steam service?

A. The boilers at the state office campus on Pleasant Street in Concord provided service for two winters. The boilers located in downtown Concord provided service for three winters, through the 2019–2020 winter. The boilers are no longer in use and thus all costs have been incurred related to this special contract.

Q. Were the final costs for installation and removal of the boilers in excess of the not-to-exceed amount?

A. Yes. Although the temporary boilers in downtown Concord were installed with few issues and within the contractor's budget, installation of the boilers behind the Department of Corrections Building, adjacent to the former Concord Steam plant, encountered many difficulties. The contractor encountered conditions that were unknown when the contractor prepared its cost projections. These conditions included unknown tunnels, unknown infrastructure in the tunnels, an empty underground cistern, unplanned removal of a building, the repeated need to re-route various piping, and other issues. As a result of these unknown and unforeseen conditions, the total contractor costs were above the not-to-exceed amount by $1,716,593 million.

Q. Did NHDAS reimburse EnergyNorth for the costs incurred that were in excess of the not to exceed limit under the agreement?

A. Not in their entirety. After significant negotiation between EnergyNorth and its contractor, the contractor reduced its bill by $100,000. This left $1,616,593 in unreimbursed costs. NHDAS agreed to seek Governor and Executive Council approval for payment of an additional $569,004, which was paid to EnergyNorth in early 2020.[15] EnergyNorth has not been reimbursed for approximately $1,047,589 in contractor costs incurred to complete this project.

15 The additional payment was the result of extensive negotiations between the Company and NHDAS.

Q. Does EnergyNorth propose to recover the outstanding costs in this proceeding?

A. Yes. While the impetus for the special contract with NHDAS was to assist NHDAS, there are benefits for all EnergyNorth customers. When NHDAS made the decision to leave the Concord Steam distribution system and convert the majority of the State of New Hampshire buildings to natural gas, it meant that Concord Steam's business model was no longer viable, that Concord Steam would have to close, which would necessitate the conversion of all Concord Steam customers to alternative fuels. EnergyNorth viewed the conversion of all Concord Steam customers, including NHDAS, as a single large conversion opportunity.[16] The Company performed the financial analysis required for investments over $1 million per the EnergyNorth tariff based on a portfolio approach, treating all the former Concord Steam customers as a single project. As a result, the Company is seeking to recover the outstanding costs associated with the NHDAS conversion in this proceeding. By adding the NHDAS connections to EnergyNorth's distribution system, the Company was able to increase its customer base and throughput over which to recover its fixed costs, thereby providing a benefit to all other customers. The Company's updated[17] analysis is provided as Attachment WJC/MRS-2.

Q. Would recovery of these costs harm other EnergyNorth customers?

A. No. As shown in Attachment WJC/MRS-2, there are benefits to EnergyNorth customers as a result of this contract and the Concord Steam customer conversions. The costs

---

16 Note that EnergyNorth successfully executed on this opportunity, acquiring over 97% of the former Concord Steam customers. The load from these customers was the equivalent of acquiring over 2100 new residential customers.

17 *See* Docket DG No. 16-770 for original DCF analysis.

incurred by the Company are similar to a line extension where EnergyNorth makes an upfront investment in order to serve a large customer and there is a benefit that accrues to the Company's other customers. The current EnergyNorth tariff requires a discounted cash flow analysis be performed for projects which require an investment over $1 million. A 10-year NPV analysis is then performed and if the result is positive the investment is considered to be a benefit for all customers. As the analysis shows in Attachment WJC/MRS-2, there is a substantially positive NPV result in the amount of $875,710, including recovery of these costs as proposed by the Company, which will flow through to all EnergyNorth customers.

Q. Is EnergyNorth seeking a return on the NHDAS costs?

A. No. As shown in the "Revenue Requirement" column, rows 1, 2, and 3 of Attachment WJC/MRS-2, EnergyNorth is simply seeking reimbursement of the funds it advanced for NHDAS' benefit three years ago, with no carrying charge, amortized over three years.

IV. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.

Attachment WJC/MRS-1

In Docket No. DG 19-161, the Secretarial Letter on September 28, 2020, stated that consistent with Order No. 26,122,[1] Liberty must also include in its next initial rate case filing "an analysis of Liberty's investment in its iNATGAS facility similar to Exhibit 46 in DG 17-048, in sufficient detail, to allow the Commission to evaluate the investment and its impacts on firm customers."

This attachment provides the updated analysis in a format similar to Exhibit 46 in Docket No. DG 17-048. Specifically, this attachment contains the following documentation:

a) **Attachment WJC/MRS-1(a):** Exhibit 46 part (a) required the Company to provide "a REVISED Attachment to Staff 1-1.e in DG 14-091 (Hall Testimony, Attachment SRH-1) that includes projected AFUDC based on the cost estimates, anticipated construction schedule and Concord property tax rate at that time. Provide supporting work papers in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact."

   Attachment WJC/MRS-1(a) provides a copy of the Company's original response to Exhibit 46 part (a), as this is an historical document that is unchanged in the updated analysis.

b) **Attachment WJC/MRS-1(b):** Exhibit 46 part (b) required the Company to provide "an updated REVISED Attachment to Staff 1-1.e in DG 14-091 (Hall Testimony, Attachment SRH-1) using the actual investment amounts (including AFUDC), calendar years corresponding to the in-service date and current Concord property tax rate. Provide supporting work papers in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact."

   Attachment WJC/MRS-1(b) provides an updated analysis of the project using the actual investment amounts (including AFUDC), calendar years corresponding to the in-service date and current Concord property tax rate.

c) **Attachment WJC/MRS-1(c):** Exhibit 46 part (c) required the Company to "update Attachment 5-4.3 to include actual monthly consumption and gross margin since May 2017."

   Attachment WJC/MRS-1(c) provides an update to Attachment 5-4.3 to include actual monthly consumption and gross margin through June 2020.

   Attachment WJC/MRS-1(c) contains confidential customer usage information and confidential pricing can be calculated from the "consumption" and "gross margin" figures.

---

[1] Order No. 26,122 (Apr. 27, 2018) stated the following with respect to the special contract with iNATGAS: "Nevertheless, the plant has been built and, for purposes of the base rates set in this case, we will allow recovery of the plant up to the level of costs presented in DG 14-091 ($2,245,000) plus related O&M expense. ***We will re-evaluate this investment in Liberty's next rate case and may consider putting more of the investment in rate base at that time***. The remedy fashioned here will put ratepayers in the position they were in when this project was approved." Id. at 31-32 (emphasis added).

The customer information is confidential pursuant to RSA 363:38, and the Commission orally granted confidential treatment of the pricing information in the underlying docket that approved the iNATGAS contract. See Transcript of 4/23/2014 prehearing conference in Docket No. DG 14-091, at page 12. A motion for confidential treatment will be filed to protect the information in this docket.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

Line			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2	Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
3			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
4																	
5	**Investment**																
6	Compressors		1,000,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Piping, meter set, survey, etc		865,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Land (pro-rated)		200,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Contingency		180,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	AFUDC based on original estimate and timeline		232,650	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Total Amount		2,477,650	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Cumulative Program Spend		2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650
13																	
14	**Deferred Tax Calculation**																
15	Annual Tax Depreciation (no bonus in 2014)	MACRS 15 year	102,250	194,275	174,848	157,465	141,719	127,404	120,655	120,655	120,860	120,655	120,860	120,655	120,860	120,655	120,860
16	Cumulative Tax Depreciation		102,250	296,525	471,373	628,838	770,556	897,960	1,018,615	1,139,270	1,260,129	1,380,784	1,501,644	1,622,299	1,743,158	1,863,813	1,984,673
17																	
18	Annual Book Depreciation (30-yr prop)	3.33%	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167
19	Cumulative Book Depreciation		68,167	136,333	204,500	272,667	340,833	409,000	477,167	545,333	613,500	681,667	749,833	818,000	886,167	954,333	1,022,500
20																	
21	Annual Book/Tax Timer		34,083	126,108	106,681	89,298	73,552	59,237	52,488	52,488	52,693	52,488	52,693	52,488	52,693	52,488	52,693
22	Cumulative Book/Tax Timer		34,083	160,192	266,872	356,171	429,723	488,959	541,448	593,936	646,629	699,117	751,810	804,298	856,991	909,480	962,172
23	Effective Tax Rate		39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%	39.61%
24																	
25	Deferred Tax Reserve		13,451	63,452	105,708	141,079	170,213	193,677	214,467	235,258	256,130	276,920	297,792	318,583	339,454	360,245	381,117
26																	
27	**Rate Base Calculation**																
28	Plant In Service		2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650	2,477,650
29	Accumulated Depreciation		(68,167)	(136,333)	(204,500)	(272,667)	(340,833)	(409,000)	(477,167)	(545,333)	(613,500)	(681,667)	(749,833)	(818,000)	(886,167)	(954,333)	(1,022,500)
30	Net Plant in Service		2,409,483	2,341,317	2,273,150	2,204,983	2,136,817	2,068,650	2,000,483	1,932,317	1,864,150	1,795,983	1,727,817	1,659,650	1,591,483	1,523,317	1,455,150
31	Deferred Tax Reserve		(13,451)	(63,452)	(105,708)	(141,079)	(170,213)	(193,677)	(214,467)	(235,258)	(256,130)	(276,920)	(297,792)	(318,583)	(339,454)	(360,245)	(381,117)
32	Year End Rate Base		2,396,032	2,277,865	2,167,442	2,063,904	1,966,604	1,874,973	1,786,016	1,697,059	1,608,020	1,519,063	1,430,025	1,341,067	1,252,029	1,163,072	1,074,033
33																	
34	**Revenue Requirement Calculation**																
35	Year End Rate Base		2,396,032	2,277,865	2,167,442	2,063,904	1,966,604	1,874,973	1,786,016	1,697,059	1,608,020	1,519,063	1,430,025	1,341,067	1,252,029	1,163,072	1,074,033
36	Pre-Tax ROR		11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
37	Return and Income Taxes		275,544	261,954	249,256	237,349	226,159	215,622	205,392	195,162	184,922	174,692	164,453	154,223	143,983	133,753	123,514
38	Book Depreciation - annual		68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167	68,167
39	Property Taxes - annual (3% inflation adj)		54,454	54,553	54,556	54,463	54,489	54,199	54,013	53,718	53,501	52,982	52,526	51,947	51,405	50,574	49,766
40	**Annual Revenue Requirement**		398,165	384,673	371,978	359,979	348,814	337,987	327,572	317,047	306,590	295,840	285,145	274,337	263,555	252,494	241,447
41																	
42	Prior Year Cumulative Revenue Requirement		-	398,165	782,838	1,154,817	1,514,795	1,863,610	2,201,597	2,529,169	2,846,216	3,152,806	3,448,646	3,733,791	4,008,128	4,271,682	4,524,176
43																	
44	Cumulative Revenue Requirement		398,165	782,838	1,154,817	1,514,795	1,863,610	2,201,597	2,529,169	2,846,216	3,152,806	3,448,646	3,733,791	4,008,128	4,271,682	4,524,176	4,765,623
45																	
46	**Minimum Take-or-Pay Assumption Level**																
47	Cumulative estimated revenue at minimum take-or-pay level		192,600	385,200	699,800	1,014,400	1,817,000	2,619,600	3,422,200	4,224,800	5,027,400	5,830,000	6,632,600	7,435,200	8,237,800	9,040,400	9,843,000
48	Cumulative revenue requirement (line 39)		398,165	782,838	1,154,817	1,514,795	1,863,610	2,201,597	2,529,169	2,846,216	3,152,806	3,448,646	3,733,791	4,008,128	4,271,682	4,524,176	4,765,623
49	Excess revenue (deficiency)		(205,565)	(397,638)	(455,017)	(500,395)	(46,610)	418,003	893,031	1,378,584	1,874,594	2,381,354	2,898,809	3,427,072	3,966,118	4,516,224	5,077,377
50	NPV	$6,276,533															
51	**Baseline Assumption Level**																
52	Cumulative estimated revenue at baseline level		314,600	781,700	1,401,300	2,325,900	3,403,000	4,632,600	5,862,200	7,274,800	8,687,400	10,100,000	11,512,600	12,925,200	14,337,800	15,750,400	17,163,000
53	Cumulative revenue requirement (line 39)		398,165	782,838	1,154,817	1,514,795	1,863,610	2,201,597	2,529,169	2,846,216	3,152,806	3,448,646	3,733,791	4,008,128	4,271,682	4,524,176	4,765,623
54	Excess revenue (deficiency)		(83,565)	(1,138)	246,483	811,105	1,539,390	2,431,003	3,333,031	4,428,584	5,534,594	6,651,354	7,778,809	8,917,072	10,066,118	11,226,224	12,397,377
55	NPV	$22,588,896															
56	**Accelerated Sales Assumption Level**																
57	Cumulative estimated revenue at accelerated sales level		467,100	1,025,700	1,828,300	3,057,900	4,287,500	5,700,100	7,112,700	8,525,300	9,937,900	11,350,500	12,763,100	14,175,700	15,588,300	17,000,900	18,413,500
58	Cumulative revenue requirement (line 39)		398,165	782,838	1,154,817	1,514,795	1,863,610	2,201,597	2,529,169	2,846,216	3,152,806	3,448,646	3,733,791	4,008,128	4,271,682	4,524,176	4,765,623
59	Excess revenue (deficiency)		68,935	242,862	673,483	1,543,105	2,423,890	3,498,503	4,583,531	5,679,084	6,785,094	7,901,854	9,029,309	10,167,572	11,316,618	12,476,724	13,647,877
60	NPV	$28,306,787															
61																	

Imputed Capital Structure/ROR

Line		Ratio	Rate	Weighted Rate	(prior federal tax rate of 35% plus NH rate of 8.5%) Pre Tax	(current federal tax rate of 34% plus NH rate of 8.5%) Pre Tax
72	Long Term Debt	50.00%	6.99%	3.50%	3.50%	3.50%
73	Short Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%
74	Common Equity	50.00%	9.67%	4.84%	8.13%	8.01%
75						
76		100.00%		8.33%	11.63% this rate is for informational purposes only	11.50%

Line / Column Notes:
39 Property tax rate reflects actual calendar year 2012 ratio of municipal tax expense to average net plant in service, with 3% inflation factor.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

1			(a)	(b)	(c)	(d)	(e)
2	Year		1	2	3	4	5
3			Year 1	Year 2	Year 3	Year 4	Year 5
4			Year 1 began on 12/1/2016				
5	**Investment**						
6	Compressors		1,100,000	-	-	-	-
7	Piping, meter set, survey, etc		3,080,084	-	-	-	-
8	Land (pro-rated)		200,000	-	-	-	-
9	Contingency		-	-	-	-	-
10	AFUDC - Actual		435,510	-	-	-	-
11	Total Amount		4,815,594	-	-	-	-
12	Cumulative Program Spend		4,815,594	4,815,594	4,815,594	4,815,594	4,815,594
13			Does not include Burdens				
14	**Deferred Tax Calculation**						
15	Annual Tax Depreciation (bonus in 2016)	MACRS 15 year	2,194,544	198,554	178,699	160,933	144,840
16	Cumulative Tax Depreciation		2,194,544	2,393,098	2,571,797	2,732,730	2,877,570
17							
18	Annual Book Depreciation (30-yr prop)	2.86%	119,550	119,550	119,550	119,550	119,550
19	Cumulative Book Depreciation		119,550	239,101	358,651	478,202	597,752
20							
21	Annual Book/Tax Timer		2,074,994	79,004	59,148	41,383	25,290
22	Cumulative Book/Tax Timer		2,074,994	2,153,997	2,213,145	2,254,528	2,279,818
23	Effective Tax Rate		39.41%	39.41%	27.24%	27.08%	27.08%
24							
25	Deferred Tax Reserve		817,706	848,890	602,861	610,526	617,375
26							
27	**Rate Base Calculation**						
28	Plant In Service		4,815,594	4,815,594	4,815,594	4,815,594	4,815,594
29	Accumulated Depreciation		(119,550)	(239,101)	(358,651)	(478,202)	(597,752)
30	Net Plant in Service		4,696,044	4,576,493	4,456,943	4,337,392	4,217,842
31	Deferred Tax Reserve		(817,706)	(848,890)	(602,861)	(610,526)	(617,375)
32	Year End Rate Base		3,878,338	3,727,603	3,854,082	3,726,866	3,600,467
33							
34	**Revenue Requirement Calculation**						
35	Year End Rate Base		3,878,338	3,727,603	3,854,082	3,726,866	3,600,467
36	Pre-Tax ROR		8.50%	8.50%	8.50%	8.50%	8.50%
37	Return and Income Taxes		329,659	316,846	327,597	316,784	306,040
38	Book Depreciation - annual		119,550	119,550	119,550	119,550	119,550
39	Property Taxes - annual (2.7% inflation adj)		129,060	129,162	129,171	129,082	128,910
40	**Annual Revenue Requirement**		578,270	565,558	576,318	565,416	554,500
41							
42	Prior Year Cumulative Revenue Requirement		-	578,270	1,143,828	1,720,146	2,285,563
43							
44	Cumulative Revenue Requirement		578,270	1,143,828	1,720,146	2,285,563	2,840,063
45							

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

1			(a)	(b)	(c)	(d)	(e)
2	Year		1	2	3	4	5
3			Year 1	Year 2	Year 3	Year 4	Year 5
4			Year 1 began on 12/1/2016				
46	**Minimum Take-or-Pay Assumption Level**						
47	Cumulative estimated revenue at minimum take-or-pay level		192,600	385,200	699,800	1,014,400	1,817,000
48	Cumulative revenue requirement (line 39)		578,270	1,143,828	1,720,146	2,285,563	2,840,063
49	Excess revenue (deficiency)		(385,670)	(758,628)	(1,020,346)	(1,271,163)	(1,023,063)
50	NPV	$212,274					
51	**Baseline Assumption Level**						
52	Cumulative estimated revenue at baseline level		314,600	781,700	1,401,300	2,325,900	3,403,000
53	Cumulative revenue requirement (line 39)		578,270	1,143,828	1,720,146	2,285,563	2,840,063
54	Excess revenue (deficiency)		(263,670)	(362,128)	(318,846)	40,337	562,937
55	NPV	$3,339,664					
56	**Accelerated Sales Assumption Level**						
57	Cumulative estimated revenue at accelerated sales level		467,100	1,025,700	1,828,300	3,057,900	4,287,500
58	Cumulative revenue requirement (line 39)		578,270	1,143,828	1,720,146	2,285,563	2,840,063
59	Excess revenue (deficiency)		(111,170)	(118,128)	108,154	772,337	1,447,437
60	NPV	$4,170,805					
61							

Imputed Capital Structure/ROR

67						
68						(current federal tax
69						rate of 21% plus
70				Weighted		NH rate of 7.7%)
71		Ratio	Rate	Rate		Pre Tax
72	Long Term Debt	49.85%	4.42%	2.20%		2.200%
73	Short Term Debt	0.95%	2.49%	0.02%		0.02%
74	Common Equity	49.21%	9.30%	4.58%		6.280%
75						
76		100.01%		6.80%		8.50%
					this rate is for informational purposes only	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

1				(f)	(g)	(h)	(i)	(j)
2	Year			6	7	8	9	10
3				Year 6	Year 7	Year 8	Year 9	Year 10
4								
5	**Investment**							
6	Compressors			-	-	-	-	-
7	Piping, meter set, survey, etc			-	-	-	-	-
8	Land (pro-rated)			-	-	-	-	-
9	Contingency			-	-	-	-	-
10	Estimated annual operating costs		see real estate taxes below	-	-	-	-	-
11	Total Amount			-	-	-	-	-
12	Cumulative Program Spend			4,815,594	4,815,594	4,815,594	4,815,594	4,815,594
13								
144,840	144,840	144,840	144,840	130,210	123,312	123,312	123,521	123,312
16	Cumulative Tax Depreciation			3,007,779	3,131,092	3,254,404	3,377,926	3,501,238
17								
18	Annual Book Depreciation (30-yr prop)		3.33%	119,550	119,550	119,550	119,550	119,550
19	Cumulative Book Depreciation			717,302	836,853	956,403	1,075,954	1,195,504
20								
21	Annual Book/Tax Timer			10,659	3,762	3,762	3,971	3,762
22	Cumulative Book/Tax Timer			2,290,477	2,294,239	2,298,001	2,301,972	2,305,734
27.08%	27.08%	27.08%	27.08%	27.08%	27.08%	27.08%	27.08%	27.08%
24								
25	Deferred Tax Reserve			620,261	621,280	622,299	623,374	624,393
26								
27	**Rate Base Calculation**							
28	Plant In Service			4,815,594	4,815,594	4,815,594	4,815,594	4,815,594
29	Accumulated Depreciation			(717,302)	(836,853)	(956,403)	(1,075,954)	(1,195,504)
30	Net Plant in Service			4,098,292	3,978,741	3,859,191	3,739,640	3,620,090
31	Deferred Tax Reserve			(620,261)	(621,280)	(622,299)	(623,374)	(624,393)
32	Year End Rate Base			3,478,030	3,357,461	3,236,892	3,116,266	2,995,697
33								
34	**Revenue Requirement Calculation**							
35	Year End Rate Base			3,478,030	3,357,461	3,236,892	3,116,266	2,995,697
36	Pre-Tax ROR			8.50%	8.50%	8.50%	8.50%	8.50%
37	Return and Income Taxes			295,633	285,384	275,136	264,883	254,634
38	Book Depreciation - annual			119,550	119,550	119,550	119,550	119,550
39	Property Taxes - annual (3% inflation adj)			128,609	128,214	127,700	127,080	126,307
40	**Annual Revenue Requirement**			543,792	533,149	522,386	511,513	500,491
41								
42	Prior Year Cumulative Revenue Requirement			2,840,063	3,383,855	3,917,004	4,439,390	4,950,903
43								
44	Cumulative Revenue Requirement			3,383,855	3,917,004	4,439,390	4,950,903	5,451,395
45								
46	**Minimum Take-or-Pay Assumption Level**							
47	Cumulative estimated revenue at minimum take-or-pay level			2,619,600	3,422,200	4,224,800	5,027,400	5,830,000
48	Cumulative revenue requirement (line 39)			3,383,855	3,917,004	4,439,390	4,950,903	5,451,395
49	Excess revenue (deficiency)			(764,255)	(494,804)	(214,590)	76,497	378,605
50								
51	**Baseline Assumption Level**							
52	Cumulative estimated revenue at baseline level			4,632,600	5,862,200	7,274,800	8,687,400	10,100,000
53	Cumulative revenue requirement (line 39)			3,383,855	3,917,004	4,439,390	4,950,903	5,451,395
54	Excess revenue (deficiency)			1,248,745	1,945,196	2,835,410	3,736,497	4,648,605
55								

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

1		(f)	(g)	(h)	(i)	(j)
2	Year	6	7	8	9	10
3		Year 6	Year 7	Year 8	Year 9	Year 10
4						
56	**Accelerated Sales Assumption Level**					
57	Cumulative estimated revenue at accelerated sales level	5,700,100	7,112,700	8,525,300	9,937,900	11,350,500
58	Cumulative revenue requirement (line 39)	3,383,855	3,917,004	4,439,390	4,950,903	5,451,395
59	Excess revenue (deficiency)	2,316,245	3,195,696	4,085,910	4,986,997	5,899,105

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

1				(k)	(l)	(m)	(n)	(o)
2	Year			11	12	13	14	15
3				Year 11	Year 12	Year 13	Year 14	Year 15
4								
5	**Investment**							
6	Compressors			-	-	-	-	-
7	Piping, meter set, survey, etc			-	-	-	-	-
8	Land (pro-rated)			-	-	-	-	-
9	Contingency			-	-	-	-	-
10	Estimated annual operating costs	see real estate taxes below		-	-	-	-	-
11	Total Amount			-	-	-	-	-
12	Cumulative Program Spend			4,815,594	4,815,594	4,815,594	4,815,594	4,815,594
13								
123,521	123,521	123,521	123,521	123,312	123,521	123,312	123,312	123,521
16	Cumulative Tax Depreciation			3,624,551	3,748,072	3,871,385	3,994,697	4,118,219
17								
18	Annual Book Depreciation (30-yr prop)		3.33%	119,550	119,550	119,550	119,550	119,550
19	Cumulative Book Depreciation			1,315,054	1,434,605	1,554,155	1,673,706	1,793,256
20								
21	Annual Book/Tax Timer			3,762	3,971	3,762	3,762	3,971
22	Cumulative Book/Tax Timer			2,309,496	2,313,467	2,317,230	2,320,992	2,324,963
27.08%	27.08%	27.08%	27.08%	27.08%	27.08%	27.08%	27.08%	27.08%
24								
25	Deferred Tax Reserve			625,412	626,487	627,506	628,525	629,600
26								
27	**Rate Base Calculation**							
28	Plant In Service			4,815,594	4,815,594	4,815,594	4,815,594	4,815,594
29	Accumulated Depreciation			(1,315,054)	(1,434,605)	(1,554,155)	(1,673,706)	(1,793,256)
30	Net Plant in Service			3,500,540	3,380,989	3,261,439	3,141,888	3,022,338
31	Deferred Tax Reserve			(625,412)	(626,487)	(627,506)	(628,525)	(629,600)
32	Year End Rate Base			2,875,128	2,754,502	2,633,933	2,513,364	2,392,738
33								
34	**Revenue Requirement Calculation**							
35	Year End Rate Base			2,875,128	2,754,502	2,633,933	2,513,364	2,392,738
36	Pre-Tax ROR			8.50%	8.50%	8.50%	8.50%	8.50%
37	Return and Income Taxes			244,386	234,133	223,884	213,636	203,383
38	Book Depreciation - annual			119,550	119,550	119,550	119,550	119,550
39	Property Taxes - annual (3% inflation adj)			125,415	124,378	123,208	121,858	103,364
40	**Annual Revenue Requirement**			489,352	478,062	466,643	455,045	426,297
41								
42	Prior Year Cumulative Revenue Requirement			5,451,395	5,940,746	6,418,808	6,885,451	7,340,496
43								
44	Cumulative Revenue Requirement			5,940,746	6,418,808	6,885,451	7,340,496	7,766,793
45								
46	**Minimum Take-or-Pay Assumption Level**							
47	Cumulative estimated revenue at minimum take-or-pay level			6,632,600	7,435,200	8,237,800	9,040,400	9,843,000
48	Cumulative revenue requirement (line 39)			5,940,746	6,418,808	6,885,451	7,340,496	7,766,793
49	Excess revenue (deficiency)			691,854	1,016,392	1,352,349	1,699,904	2,076,207
50								
51	**Baseline Assumption Level**							
52	Cumulative estimated revenue at baseline level			11,512,600	12,925,200	14,337,800	15,750,400	17,163,000
53	Cumulative revenue requirement (line 39)			5,940,746	6,418,808	6,885,451	7,340,496	7,766,793
54	Excess revenue (deficiency)			5,571,854	6,506,392	7,452,349	8,409,904	9,396,207
55								

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Request for Approval of Special Contract and Lease Agreement with Innovative Natural Gas, LLC d/b/a iNATGAS
Computation of Revenue Requirement

1		(k)	(l)	(m)	(n)	(o)
2	Year	11	12	13	14	15
3		Year 11	Year 12	Year 13	Year 14	Year 15
4						
56	**Accelerated Sales Assumption Level**					
57	Cumulative estimated revenue at accelerated sales level	12,763,100	14,175,700	15,588,300	17,000,900	18,413,500
58	Cumulative revenue requirement (line 39)	5,940,746	6,418,808	6,885,451	7,340,496	7,766,793
59	Excess revenue (deficiency)	6,822,354	7,756,892	8,702,849	9,660,404	10,646,707

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Annual revenue requirement	578,270	565,558	576,318	565,416	554,500	543,792	533,149	522,386	511,513	500,491	489,352	478,062	466,643	455,045	426,297
Minimum Take-or-Pay Assumption Level															
Annual estimated revenue at minimum take-or-pay level	192,600	192,600	314,600	314,600	802,600	802,600	802,600	802,600	802,600	802,600	802,600	802,600	802,600	802,600	802,600
Annual revenue requirement (line 6)	578,270	565,558	576,318	565,416	554,500	543,792	533,149	522,386	511,513	500,491	489,352	478,062	466,643	455,045	426,297
Excess revenue (deficiency)	(385,670)	(372,958)	(261,718)	(250,816)	248,100	258,808	269,451	280,214	291,087	302,109	313,248	324,538	335,957	347,555	376,303
NPV $212,274															
Baseline Assumption Level															
Annual estimated revenue at baseline level	314,600	467,100	619,600	924,600	1,077,100	1,229,600	1,229,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600
Annual revenue requirement (line 6)	578,270	565,558	576,318	565,416	554,500	543,792	533,149	522,386	511,513	500,491	489,352	478,062	466,643	455,045	426,297
Excess revenue (deficiency)	(263,670)	(98,458)	43,282	359,184	522,600	685,808	696,451	890,214	901,087	912,109	923,248	934,538	945,957	957,555	986,303
NPV $3,339,664															
Accelerated Sales Assumption Level															
Annual estimated revenue at accelerated level	467,100	558,600	802,600	1,229,600	1,229,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600	1,412,600
Annual revenue requirement (line 6)	578,270	565,558	576,318	565,416	554,500	543,792	533,149	522,386	511,513	500,491	489,352	478,062	466,643	455,045	426,297
Excess revenue (deficiency)	(111,170)	(6,958)	226,282	664,184	675,100	868,808	879,451	890,214	901,087	912,109	923,248	934,538	945,957	957,555	986,303
NPV $4,170,805															

II-606

Usage Month	Consumption	Gross Margin	Rent
16-Dec	[redacted]		
17-Jan			
17-Feb			
17-Mar			
17-Apr			
17-May			
17-Jun			
17-Jul			
17-Aug			
17-Sep			
17-Oct			
17-Nov			
17-Dec			
18-Jan			
18-Feb			
18-Mar			
18-Apr			
18-May			
18-Jun			
18-Jul			
18-Aug			
18-Sep			
18-Oct			
18-Nov			
18-Dec			
19-Jan			
19-Feb			
19-Mar			
19-Apr			
19-May			
19-Jun			
19-Jul			
19-Aug			
19-Sep			
19-Oct			
19-Nov			
19-Dec			
20-Jan			
20-Feb			
20-Mar			
20-Apr			
20-May			
Totals		[redacted]	
Combined Total			
			[redacted]

Docket No. DG 20-105
Attachment WJC/MRS-2
Page 1 of 1

Rate Base model	CapEx
Capital Cost	$926,500
Required Return (pre tax)	8.50%
Depreciation	61,767
OpEx	
10-year Net Present Value	$875,710
Up-front Payment	$1,900,000
5-year amort	($482,202)
DAS Recovery	$1,047,589

	Ratio	Rate	Weighted Rate	(current federal tax rate of 21% plus NH rate of 7.7%) Pre Tax
Long Term Debt	49.85%	4.42%	2.20%	2.20%
Short Term Debt	0.95%	2.49%	0.02%	0.02%
Common Equity	49.21%	9.30%	4.58%	6.28%
	100%		6.80%	8.50%

	MACRS Rates (%)	MACRS Table	Book Depr	Delta	Tax Rate	DIT	ADIT	Rate Base	Return Required	Property Tax 3% actual Concord	Insurance	O&M	Amortization of Initial Payment	Revenue Requirement	Actual Revenues	Delta
								$926,500								
1	5	$ 46,325	$ 23,163	$(23,163)	27.08%	$ (6,272)	$ (6,272)	$897,065	$77,535	$27,795	$2,761	$4,470	$482,202	$967,121.66	$816,221.00	($150,900.66)
2	9.5	$ 88,018	$ 23,163	$(64,855)	27.08%	$(17,563)	$ (23,835)	$856,340	$74,552	$26,912	$2,761	$4,582	$482,202	$963,367.26	$602,276.00	($361,091.26)
3	8.55	$ 79,216	$ 23,163	$(56,053)	27.08%	$(15,179)	$ (39,014)	$817,998	$71,190	$25,690	$2,761	$4,696	$482,202	$958,898.24	$617,332.90	($341,565.34)
4	7.7	$ 71,341	$ 23,163	$(48,178)	27.08%	$(13,047)	$ (52,061)	$781,789	$68,021	$24,540	$2,761	$4,814	$482,202	$605,499.44	$632,766.22	$27,266.79
5	6.93	$ 64,206	$ 23,163	$(41,044)	27.08%	$(11,115)	$ (63,176)	$747,512	$65,024	$23,454	$2,761	$4,934	$482,202	$601,536.53	$648,585.38	$47,048.84
6	6.23	$ 57,721	$ 23,163	$(34,558)	27.08%	$ (9,358)	$ (72,534)	$714,991	$62,183	$22,425	$2,761	$5,057		$115,589.83	$664,800.01	$549,210.18
7	5.9	$ 54,664	$ 23,163	$(31,501)	27.08%	$ (8,530)	$ (81,065)	$683,298	$59,453	$21,450	$2,761	$5,184		$112,010.36	$681,420.01	$569,409.65
8	5.9	$ 54,664	$ 23,163	$(31,501)	27.08%	$ (8,530)	$ (89,595)	$651,605	$56,758	$20,499	$2,761	$5,313		$108,494.09	$698,455.51	$589,961.42
9	5.91	$ 54,756	$ 23,163	$(31,594)	27.08%	$ (8,556)	$ (98,151)	$619,887	$54,062	$19,548	$2,761	$5,446		$104,980.00	$715,916.90	$610,936.90
10	5.9	$ 54,664	$ 23,163	$(31,501)	27.08%	$ (8,530)	$(106,681)	$588,194	$51,366	$18,597	$2,761	$5,582		$101,468.47	$733,814.82	$632,346.35
11	5.91	$ 54,756	$ 23,163	$(31,594)	27.08%	$ (8,556)	$(115,237)	$556,476	$48,670	$17,646	$2,761	$5,722		$97,961.10	$752,160.19	$654,199.10
12	5.9	$ 54,664	$ 23,163	$(31,501)	27.08%	$ (8,530)	$(123,767)	$524,783	$45,974	$16,694	$2,761	$5,865		$94,456.46	$770,964.20	$676,507.73
13	5.91	$ 54,756	$ 23,163	$(31,594)	27.08%	$ (8,556)	$(132,323)	$493,065	$43,277	$15,743	$2,761	$6,012		$90,956.16	$790,238.30	$699,282.14
14	5.9	$ 54,664	$ 23,163	$(31,501)	27.08%	$ (8,530)	$(140,853)	$461,372	$40,581	$14,792	$2,761	$6,162		$87,458.77	$809,994.26	$722,535.49
15	5.91	$ 54,756	$ 23,163	$(31,594)	27.08%	$ (8,556)	$(149,409)	$429,654	$37,885	$13,841	$2,761	$6,316		$83,965.88	$830,244.12	$746,278.23
16	2.95	$ 27,332	$ 23,163	$ (4,169)	27.08%	$ (1,129)	$(150,538)	$405,362	$35,504	$12,890	$2,761	$6,474		$80,790.80	$851,000.22	$770,209.42
17			$ 23,163	$ 23,163	27.08%	$ 6,272	$(144,265)	$388,472	$33,753	$12,161	$2,761	$6,636		$78,472.92	$872,275.23	$793,802.31
18			$ 23,163	$ 23,163	27.08%	$ 6,272	$(137,993)	$371,582	$32,316	$11,654	$2,761	$6,802		$76,695.83	$894,082.11	$817,386.28
19			$ 23,163	$ 23,163	27.08%	$ 6,272	$(131,720)	$354,692	$30,880	$11,147	$2,761	$6,972		$74,922.88	$916,434.16	$841,511.28
20			$ 23,163	$ 23,163	27.08%	$ 6,272	$(125,448)	$337,802	$29,444	$10,641	$2,761	$7,146		$73,154.19	$939,345.01	$866,190.83

II-608