Liberty Utilities

EXHIBIT
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DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

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

REBUTTAL TESTIMONY

OF

WILLIAM J. CLARK

AND

STEPHEN R. HALL

January 25, 2018

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I. INTRODUCTION

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

A. My name is William J. Clark and my title is Director, Business Development. My business address is 116 North Main Street, Concord, New Hampshire.

My name is Stephen R. Hall and my title is Director, Rates and Regulatory Affairs. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. By whom are you employed?

A. We are employed by Liberty Utilities Service Corp. ("Liberty"), which provides services to Liberty Utilities (EnergyNorth Natural Gas) Corp. ("EnergyNorth" or the "Company").

Q. On whose behalf are you testifying today?

A. We are testifying on behalf of EnergyNorth.

Q. Mr. Clark, please state your educational background and professional experience.

A. I graduated from St. Anselm College in Goffstown, New Hampshire, with a Bachelor of Science degree in Financial Economics in 1991. I began my career in 1992 at Boston Gas Company where I was a member of the Steel Workers of America, Local 12007 and held various positions in gas distribution and customer service, as well as being a union official. In 1998 I was employed by National Grid to start an unregulated energy service subsidiary where I worked as a Sales Account Manager until 2010. When National Grid sold this business in 2010, I was employed by National Grid as a Commercial Gas Sales Representative, working in EnergyNorth's service territory. I joined Liberty in 2012 and progressed into my current position where I am responsible for organic growth opportunities and commercial development for both EnergyNorth and Granite State Electric.

Q. Have you previously testified before the Commission?

A. Yes, I have testified before the Commission regarding EnergyNorth's business expansion plans, including franchise applications, and I have submitted testimony in the docket on Managed Expansion Plan rates.

Q. Mr. Hall, please state your educational background and professional experience.

A. I received a Bachelor of Science degree in Mathematics Education from the University of New Hampshire in 1977 and a Master's Degree in Business Administration from the University of New Hampshire in 1979. From 1979 through August 2013, I was employed by Public Service Company of New Hampshire ("PSNH") in positions of progressive responsibility in the rates and regulatory area of the company. My responsibilities included all aspects of cost recovery and ratemaking, rate design, tariff administration, as well as regulatory relations and supervisory responsibility for revenue requirements. I joined Liberty Utilities in September 2013 and assumed my current responsibilities for rates and regulatory affairs at that time.

Q. Have you previously testified before the Commission?

A. Yes, I have testified extensively before the Commission during my 34-year career at PSNH and more recently on behalf of Liberty. My testimony has covered a wide range of regulatory, ratemaking, and pricing issues, as well as testimony in support of numerous special contracts.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. Our testimony provides comments on portions of Staff witness Stephen Frink's testimony regarding Staff's position on the Keene rate consolidation proposal, and on Staff's position regarding the iNATGAS project and cost recovery. We also provide comments on the portion of James Brennan's testimony dealing with the Office of the Consumer Advocate's ("OCA") position on the Keene rate consolidation proposal.

III. KEENE RATE CONSOLIDATION

Q. Please summarize EnergyNorth's proposal on the Keene Division rate consolidation.

A. In its April 28, 2017, filing in this docket, the Company proposed that the Keene Division be consolidated into EnergyNorth from a ratemaking and accounting perspective, and that customers in the Keene Division be charged the same distribution rates as EnergyNorth's other customers. EnergyNorth made this proposal in view of the fact that the Keene Division is not currently profitable,[1] which would necessitate the filing of a separate rate case for the Keene Division, if the Company's proposal to consolidate rates is rejected. The Company noted the relatively high cost of filing a rate case for the Keene Division, the significant administrative burden associated with continuing to treat the Keene

[1] The unprofitable position of the Keene Division is not a new phenomenon as the predecessor entity, New Hampshire Gas Corporation, had been unprofitable in the years leading up to its acquisition by EnergyNorth at the beginning of 2015.

Division as a separate entity, and the significant increase in bills that would result if the revenue deficiency were recovered exclusively from Keene customers. In addition, the consolidation of the Keene Division into EnergyNorth would facilitate the ability to expand the Keene system, thereby providing benefits to all customers.

Q. Please summarize the positons taken by Staff on the Keene rate consolidation proposal.

A. Staff stated that consolidating rates would produce cost-shifting and result in financial harm to EnergyNorth's existing customers. Staff alleged that the administrative cost of a separate rate case filing for Keene could be minimized. Staff also claimed that dramatic rate increases could be avoided by limiting investments, holding down costs, and phasing in rate increases. Staff further offered that EnergyNorth could do one of the following to address the issue: (1) file a petition requesting a rate increase for Keene; (2) propose a rate plan leading to rate consolidation based on a comprehensive business plan demonstrating a quantifiable benefit for all customers (or at least no harm to customers); or (3) discontinue service to Keene customers, if customers can conveniently be converted to an alternate fuel source.

Q. Please summarize the OCA's position on the Keene rate consolidation proposal.

A. Similar to Staff's position, OCA's position is that the revenue requirement for Keene should be removed and rates should not be consolidated because the acquisition was premised on the "no net harm" standard, and that EnergyNorth has not developed a financial analysis that would indicate a reversal of operating losses in Keene.

Q. Do you have comments on Staff's and OCA's positions regarding the allegations in their testimony?

A. Yes, we believe that both Staff and OCA are incorrect and that their criticisms of the Company's position are incorrect and are based on a lack of understanding and on unreasonable expectations.

Q. Please first address Staff's assertion that cost-shifting associated with the rate consolidation proposal will result in financial harm to EnergyNorth's customers.

A. Staff is incorrect that financial harm to EnergyNorth's customers will result from the Company's proposal. The alleged "financial harm" can be quantified with some straightforward calculations. The proposed annual revenue deficiency for the Keene Division is $883,697, as shown on Attachment WJC/SRH-1. This amount is the updated revenue requirement contained in the Company's response to Staff Tech 1-1 - Supplemental. Dividing this amount by EnergyNorth's annual normalized therm sales of 159,761,663 (on Bates 227 of the April 29, 2017, filing) yields an average per therm amount of $0.0055 per therm. An average residential customer uses slightly less than 800 therms per year, so if we multiply the $0.0055 per therm by 800 therms, the result is an average increase of $4.40 *per year*, or 37 cents per month for a residential customer. This calculation assumes that there would be no load growth in the Keene Division as a result of the rate consolidation. Clearly, a bill impact of 37 cents per month with respect to distribution rates[2] can hardly be considered as causing financial harm to EnergyNorth's customers, or an unreasonable shifting of costs, especially since that impact can be substantially mitigated through load growth, which will be achievable once rates for Keene Division customers are reduced. We will address the impact of load growth later in this testimony.

Q. Has the Commission approved rate consolidation plans in prior dockets that resulted in increased bills for existing customers?

A. Yes, it has done so on several occasions. In Order No. 23,171 (Mar. 23, 1999) in Docket No. DE 98-186, the Commission approved the transfer of the Souhegan Woods Water System from Pennichuck East Utility, Inc. to Pennichuck Water Works, Inc. At the time, Pennichuck East rates were $4.289 per 100 cubic feet, while rates for Pennichuck Water Works were $1.33 per 100 cubic feet. The Commission noted,

> Staff did not object to the transfer of the system, but noted that it did not appear the new rate would cover the cost of service to the system on a stand-alone basis. Thus the Nashua core [Pennichuck Water Works' existing customers] would be forced to subsidize the rates of these customers.

[2] It should also be noted that upon consolidation the Keene customers would also begin paying EnergyNorth's Local Delivery Adjustment Charge ("LDAC") which would lessen the burden of recovering the various LDAC costs now being recovered only from current EnergyNorth customers.

Applying the "no net harm" standard,[3] the Commission nonetheless determined that it "could not conclude that the proposed transfer of the system would harm" Pennichuck Water Works' existing customers.

In Order No. 23,146 (Feb. 11, 1999) in Docket Nos. DR 97-188 and DR 98-112, the Commission approved a rate consolidation plan, concluding,

> the benefits of rate consolidation in this case outweigh the negative impacts. An overriding consideration that favors rate consolidation is the wide disparity in rates among customers of the individual systems that would result from denying Lakes Region's request…. We are particularly concerned about the rate levels that would result from a denial of Lakes Region's request for the customers of the Deer Run, Brake Hill and Tamworth systems. For example, customers of Brake Hill would be facing a 200% rate increase absent consolidation. As in Pennichuck, we find that such rates are outside the zone of 'just and reasonable.' In addition to the foregoing considerations, we also believe that rate consolidation will have the salutary effect of encouraging financially sound utilities to acquire community systems that are not otherwise attractive acquisitions in the short term. Rate consolidation is therefore a policy that promotes the expansion of public water systems, which we believe is in the overall public good.

[3] "Under the public interest or public good standard to be applied by the Commission when one utility seeks to acquire a jurisdictional utility, the Commission must determine that the proposed transaction will not harm ratepayers."

Q. Staff states that the Company made no effort to demonstrate how customers might benefit from the proposed rate consolidation plan. Has the Commission ever required such a demonstration when it approved previous rate consolidation plans?

A. The Company is unaware of any such requirement, and Staff is also unaware of such a requirement. In its response to data request LU-24 (Attachment WJC/SRH-2), Staff stated that they are unaware of any Commission orders on rate consolidation that require a demonstration of potential current and future benefits to be realized through rate consolidation. Staff is therefore suggesting that, in this particular case, the Commission depart from previous practice and precedent, and require a demonstration of benefits to all other customers. As in the previous cases, the evidence in this case shows that the public good is served through a rate consolidation plan.

Q. Absent a rate consolidation, what increase would be proposed for the Keene Division's distribution rates?

A. Distribution rates for Keene Division customers would need to increase by approximately 66% (34% for total rate level), as shown on Attachment WJC/SRH-1. We believe that the Commission could conclude that this level of increase is outside the zone of "just and reasonable," especially since the Keene Division's distribution rates are already at a higher level than EnergyNorth's distribution rates. High distribution rates for a small system such as Keene, just like some of the acquired water utilities mentioned above, are a function of a small group of customers being required to bear the burden of significant capital investments.

Q. Has the Commission approved rate consolidation plans for utilities other than water utilities?

A. Yes, it has. In Order No. 24,176 (Mar. 23, 2003) in Docket No.DE 03-030, the Commission approved a settlement providing for the acquisition by PSNH of the assets of Connecticut Valley Electric Company ("CVEC"). As part of that settlement, PSNH paid CVEC for its stranded costs associated with a power purchase agreement, with recovery of those costs from all of PSNH's customers. The Commission found that,

> the alternative, which we find to be inconsistent with the public interest, is to leave the Claremont area with the economic burden of being <u>the only area in the state saddled with unreasonably high electric rates</u> and without the benefits of electric industry restructuring. (Emphasis added.)

Q. Are there areas in EnergyNorth's service territory that have different cost structures and therefore result in cost shifting?

A. Yes, there are. EnergyNorth serves customers in Berlin and in Amherst that are physically separate from the rest of EnergyNorth's distribution system. Berlin customers are served from the PNGTS pipeline, while customers in Amherst are provided propane service from a small propane storage facility that EnergyNorth owns in Amherst. Customers in both locations are billed the same distribution rates and the same cost of gas rates as EnergyNorth's other customers, yet the cost associated with providing service from the PNGTS pipeline and from the propane storage facility differ significantly from the cost of providing service to all other customers. Cost differences are due to different distribution costs, as well as different costs for the commodity.

The Commission has recognized that, although these small segments of EnergyNorth's system can have significantly different costs of service than other areas, it is in the public good to bill all customers under the same rates, rather than have separate rates for different areas of the service territory. The Company's proposed consolidation of the Keene Division is not a departure from past precedent and is consistent with prior Commission orders.

Q. Please respond to Staff's and OCA's contention that the "no net harm" standard will be violated if there is a rate consolidation.

A. Staff and OCA appear to conclude that the "no net harm" standard is an absolute that applies in perpetuity -- that rates can never be consolidated unless there will be benefits for all customers. In view of the regulatory history of rate consolidations described above, this view is in conflict with the Commission's previous decisions, based upon the cost shifting that has been approved in other dockets. In fact, in Docket No. DG 14-155, which addressed EnergyNorth's acquisition of what became the Keene Division, the Settlement Agreement approved by the Commission clearly contemplated that EnergyNorth would propose a rate consolidation plan in a future proceeding. The parties also agreed that EnergyNorth would bill the Keene Division $200,000 annually for corporate expenses, based on the amount that New Hampshire Gas was previously charged for such services by Iberdrola. There was no cost study performed to determine this amount. Therefore, a cost shifting has already resulted from the approval of the settlement, although, unless two sets of books had been maintained since the acquisition---one with the $200,000 annual charge and second with tracking of costs that were not allowed to be charged to the Keene Division (see below)—it is not possible to determine which group of customers received a subsidy and which group incurred the subsidy, nor is it possible to determine the amount of the subsidy. Even with this undefined cross subsidy, the Commission found that, at the time of the acquisition, the settlement met the "no net harm" standard. Thus, there is room in the "no net harm" standard for a modest, reasonable, cross subsidy that provides a needed benefit to customers.

Q. Please comment on Staff's allegation that EnergyNorth failed to calculate the cost of corporate services to serve the Keene Division.

A. Staff is misinterpreting what was required under the Settlement Agreement in Docket No. DG 14-155. That agreement provided for a fixed amount ($200,000 annually) to be charged to the Keene Division by EnergyNorth for corporate services. There is nothing in the agreement that requires a separate accounting for the cost of the specific services provided by EnergyNorth. Staff concedes this point in its response to data request LU-25 (Attachment WJC/SRH-3), where Staff was given the opportunity to show that EnergyNorth was required to separately account for the cost of corporate service provided by EnergyNorth, yet failed to find anything supporting the need for that requirement. In that response, Staff suggested that the order approving the settlement "indirectly provides" for a separate calculation of corporate costs. Staff's assertion that the Company should be held to undefined, "indirect" requirements of a Commission approved settlement is unreasonable. To the contrary, the provision in the settlement to charge the Keene Division a fixed annual amount for corporate costs obviated the need for separately tracking the cost of corporate services to the Keene Division. If such a requirement existed, EnergyNorth would have accounted for such services. Since there was no such provision in the settlement, there was no separate accounting performed and it would have been unreasonable, and arguably imprudent, to incur the administrative cost associated with separate accounting in a situation where it was unnecessary to do so. Now, over three years later, Staff chastised the Company for failing to do something that it was not required to do under the settlement that Staff signed and the Commission approved. Staff's contention that EnergyNorth somehow failed to calculate the costs for corporate services is puzzling, because if Staff wanted such a calculation to be performed, it could have negotiated that specific provision in the settlement.

Q. Please comment on Staff's assertion that EnergyNorth was "put on notice" that cost shifting for the Keene Division would be a concern.

A. Staff cites its own testimony from that docket in which Staff expressed concern that consolidating rates would lead to cost shifting. While Staff may have taken that position initially, that testimony was essentially superseded when Staff entered into a settlement. Recall that EnergyNorth's testimony proposed a rate consolidation phased in over a period of two years. Both Staff and OCA disagreed with EnergyNorth's position in their testimony, and the parties entered into negotiations that resulted in settlement. Staff cannot now rely on its initial testimony in that docket as precedent any more than EnergyNorth can rely on its testimony recommending rate consolidation as precedent. The parties, through the give and take of negotiations, reached agreement resolving the acquisition of New Hampshire Gas Corporation. That agreement, which is contained in the settlement that the Commission approved, not in the pre-settlement testimony, provides precedent on this matter.

Q. Please discuss Staff's claim that a detailed business plan including a DCF analysis is required in order for EnergyNorth to proceed with its rate consolidation plan.

A. Staff states that since EnergyNorth is moving forward with its plans to convert the Keene Division to compressed natural gas ("CNG") and/or liquefied natural gas ("LNG"), one could reasonably assume that the Company has undertaken a financial analysis that shows a positive return on investment. In fact, EnergyNorth has performed an analysis showing the growth potential in the Keene Division, as we will describe below. Staff appears to be conflating the current efforts to convert a small portion of the system to CNG with EnergyNorth's growth plans for the area, and EnergyNorth's proposal to consolidate rates. The conversion to CNG that is currently being undertaken is being done for safety and reliability reasons. This isolated conversion will avoid the need to have 24-hour coverage at the propane-air plant during the winter months. It is not being done for rate consolidation purposes, nor is it being done for growth, although the conversion may result in additional load.

Q. Please discuss the analysis EnergyNorth has performed regarding growth potential in the Keene Division and the impact such growth will have on overall rate level.

A. In response to a discovery request from Staff for a comprehensive business plan that includes a Discounted Cash Flow ("DCF") analysis, EnergyNorth provided an analysis to Staff in response to Request No. Staff 2-41 on June 30, 2017, and provided an updated response on October 31, 2017. The updated response is contained in Confidential Attachment WJC/SRH-4. The attachment shows growth estimates for each of the five phases, the time frame for construction of each of the phases, maps and construction cost estimates for each of the phases, a DCF analysis for each of the five phases, as well as a combined DCF analysis. The DCF analysis was premised on EnergyNorth's temporary rate level in effect as of July 1, 2017, and it shows that all five phases have a positive net present value ("NPV") and a positive contribution in each year. While that annual contribution may not exceed the revenue shortfall associated with the Keene Division, it will significantly reduce the impact on all other customers.

For example, by the fifth year, the additional revenue associated with expansion will offset all but approximately $200,000 of any revenue shift that may occur. Moreover, we believe that the analysis is conservative and that the additional revenue could exceed what is estimated.

Q. At what point will EnergyNorth complete a detailed business plan?

A. As stated in Confidential Attachment WJC/SRH-4, EnergyNorth will complete a final business plan once the Commission approves EnergyNorth's request to consolidate rates. That detailed plan will include a marketing plan, a description of operations, and utilization of EnergyNorth's sales force to obtain additional load, among other items.

Q. Please explain why EnergyNorth has not completed a detailed business plan thus far.

A. EnergyNorth's growth projections for the Keene Division are highly dependent on the rate level for customers in that area. Unless and until a rate consolidation plan is approved, it would not be productive to perform a detailed analysis and develop a business plan, since there is a direct linkage between price and the willingness of customers to take gas service. The detailed business plan will incorporate better estimates of load growth based on discussions with potential customers, and would be more robust than the analysis contained in Confidential Attachment WJC/SRH-4. If the Commission does not approve the rate consolidation plan, thus leaving the Keene Division with much higher rates, it would limit EnergyNorth's ability to offer a competitively priced alternative for potential customers, which would limit growth in Keene.

Additionally, prior to completing the business plan, EnergyNorth will need to perform a detailed engineering design for the distribution system and supply facility that will be used to plan the construction and expansion of the system. EnergyNorth will rely on an external engineering firm to perform that design. Without approval of a rate consolidation plan, it is imprudent to incur the significant cost associated with system design, given the Keene Division's current rate level.

Q. What leads you to that conclusion?

A. An examination of the recent history of net customer growth in Keene demonstrates the challenges the Company faces in growing the Keene Division at existing rates. The table below shows the net change in services over the last four years:

Year	Services Added	Services Lost	Net Change
2014	4	5	(1)
2015	6	4	2
2016	8	3	5
2017	1	0	1
Total	19	11	7

Q. What prevents EnergyNorth from commencing discussions with potential customers prior to approval of the rate consolidation?

A. Customers want certainty if they are going to make a major commitment regarding their fuel source. They will want to know not only the price but also the timing of the availability of service to allow them to plan for the transition to gas service, especially business customers. Businesses are unlikely to respond to a proposal that involves an uncertain price level or unknown time frame for service. Neither Staff nor OCA acknowledge the reality of the business decisions that customers must make when they insist that EnergyNorth develop a detailed business plan prior to knowing whether the rate consolidation plan will be approved.

Q. You mentioned the timing of the availability of service as an uncertainty. Why is this an issue?

A. At this point, EnergyNorth does not yet know when it will be able to provide natural gas service to the Keene Division. On April 21, 2017, EnergyNorth filed a Petition for Declaratory Ruling with the Commission requesting a finding that EnergyNorth did not need to file for franchise rights to serve the Keene Division with natural gas (Docket No. DG 17-068). This filing arose out of a discussion with Staff in late March 2017 regarding EnergyNorth's efforts to construct a temporary CNG facility to serve a portion of the Keene Division with natural gas during the2017-2018 winter, during which Staff expressed the opinion that EnergyNorth needed to obtain franchise rights to provide natural gas service to Keene. EnergyNorth did not agree with Staff's opinion, thus prompting the Petition.

Six months later, on October 20, 2017, the Commission issued an Order on Declaratory Ruling concluding that EnergyNorth has the authority to supply CNG and LNG service to Keene. The Commission further ordered that EnergyNorth,

> provide all final plans for engineering, construction, installation, testing, operations, public awareness, maintenance, emergency response, procedures, and schematics, including qualifications and training of personnel, in sufficient detail as requested by the Commission's Safety Division. Further, before gas flows through these installations, we must receive a report from the Safety Division assessing the adequacy of the Company's plans and the satisfactory completion of a physical inspection of all installations.

EnergyNorth worked with the Safety Division and provided all the required information, but as of the date of this testimony, the Safety Division has not yet provided the Commission with a report on its assessment. As a result, EnergyNorth will be unable to convert customers to CNG service this winter, even if the report is issued in the near future, as interrupting service to customers during cold weather is not in their best interests.

We note the above not to criticize the process, but to demonstrate that there is significant uncertainty over the date when EnergyNorth will be able to provide natural gas service to this small number of customers in the Keene Division. In view of this uncertainty of the timing of service as well as to the rate level, it is unrealistic to ask customers to commit to take service at an unspecified future date and at unknown prices.

Q. Are there other concerns regarding EnergyNorth's ability to expand in Keene?

A. Yes. Staff's testimony gives rise to other concerns. Staff testified that an option is for the Company to discontinue service in Keene, and that the revenue deficiency, if recovered solely from Keene customers, could lead to a death spiral. These comments from Staff could significantly impair EnergyNorth's ability to acquire new customers until these issues are resolved.

Q. Why is that the case?

A. If a potential customer reads Staff's testimony, they could assume that it is likely that rates for Keene customers will increase dramatically, and that EnergyNorth may ultimately abandon the service territory. Customers do not have the depth and breadth of understanding of the issues as Staff, and they may understandably rely on Staff's expertise. Customers may ultimately conclude from Staff's characterization that there is no reasonable solution. If potential customers reach this conclusion, it is unlikely that they would be willing to commit to an investment to change their fuel source in order to take service from EnergyNorth. The Company may face this skepticism even if the Commission ultimately approves the Company's proposal in light of Staff's testimony.

Q. Do you have any comments on OCA's testimony regarding Keene Division rate consolidation?

A. Yes, we do. Mr. Brennan's testimony recommends removal of the revenue shortfall for the Keene Division from EnergyNorth's proposed increase. Mr. Brennan cites the "no net harm" standard for utility acquisitions as a basis for his recommendation, but does not offer any further support. We have already addressed the "no net harm" issue previously in this testimony, so we will not elaborate further here.

Q. What action should the Commission take regarding the Company's proposal to consolidate rates for the Keene Division?

A. The Commission should approve EnergyNorth's proposal and allow the Company to set distribution rates for the Keene Division at the same level as rates for EnergyNorth's other customers. The Commission should also make clear that growth of the Company's system is good for all customers and it supports efforts to expand the Company's customer base, in order to avoid any potential reluctance by customers to convert their fuel source.

IV. <u>iNATGAS COST RECOVERY</u>

Q. Please summarize the Special Contract with iNATGAS approved in Docket No. DG 14-091.

A. In Docket No. DG 14-091, EnergyNorth received approval for a Special Contract and Lease Agreement with Innovative Natural Gas (iNATGAS) for construction of a CNG fueling facility to supply both bulk transportation and vehicle refueling. The agreements provide for EnergyNorth to own the land, permanent site structures, and certain equipment, and for iNATGAS to own certain other equipment and to be responsible for all utilities and maintenance of all equipment regardless of ownership. Rent for the land is a fixed monthly amount. iNATGAS is also responsible for monthly meter charges and a minimum amount of distribution revenues. The contract term is 15 years with an option to extend the term for 5 years. The distribution charge is a fixed charge per dekatherm, with annual take-or-pay minimums for the full term of the contract. In addition, there is an Escrow Agreement, Maintenance Agreement, and Guaranty Agreement as security for recovery of the take-or-pay minimum amount of revenue. The estimated direct cost of the facility, as designed at that time, was $2,245,000.

Q. Have you read Staff witness Frink's testimony and his recommendation regarding the iNATGAS project?

A. Yes, we have. Staff recommended that the Commission disallow recovery of $2.5 million in costs incurred to complete the iNATGAS project.

Q. Do you believe there are inaccuracies contained in Staff's testimony which led to errors in Staff's description of the arrangement?

A. Yes. First, Staff's testimony states, beginning on Bates 000015, Line 13:

> Under the terms of the special contract Liberty constructed, owns and operates a CNG station that provides CNG to iNATGAS at a fixed per therm charge for 15 years and in each of the first 5 years iNATGAS pays for a minimum number of therms whether or not those volumes are actually taken, referred to as a 'take-or-pay' or 'must take' requirement.

Staff asserts here that the take-or-pay requirement is only in effect for the first five years of the contract. That is not the case. The Special Contract's take-or-pay requirement is in effect for the entire 15-year term of the contract, as stated in Section 1.5 of the Special Contract:

> Minimum Annual Transportation Quantity: The Customer's Minimum Annual Transportation Quantity ("MinTQ") will be broken into three intervals. The Customer may roll over a shortfall of its MinTQ requirement into the following year once during the term of the Special Contract. In such case, the Customer will pay the applicable charges in the shortfall year for the dekatherms actually delivered. The Customer's MinTQ obligations apply irrespective of whether the Customer takes Supplier Service, i.e., a third party sells gas to the Customer, or takes Sales Service, i.e., the Company sells gas to the Customer.
>
> Interval I is the time period beginning on the Service Commencement Date, as defined herein, and ends twenty-four (24) calendar months following the Service Commencement Date. But in any event the end of Interval I shall not extend beyond December 31, 2016. During this

> interval, the Customer's MinTQ will be 300,000 dekatherms per year. [[4]]
>
> Interval 2 begins with the end of Interval l and continues for twenty-four (24) calendar months. During this interval, the Customer's MinTQ will be 500,000 dekatherms per year.
>
> Interval 3 begins with the end of Interval 2 and extends for the remaining term of this Special Contract, which is described in Section 4.0. During this interval, the Customer's MinTQ shall be 1,300,000 dekatherms per year.

Section 4.1 of the Special Contract states: "This Special Contract shall become effective on the date first written above and remain in full force and effect for a period of fifteen (15) years from the Service Commencement Date …."

Q. Is the 15-year "take-or-pay" requirement a material term of the Special Contract?

A. Yes. iNATGAS is bound by these annual take-or-pay requirements for the full 15-year term. Even with the increased capital cost associated with the completion of the facility, the NPV is positive with these take-or-pay amounts over the contract term. EnergyNorth negotiated the take-or-pay minimum to ensure that it would recover sufficient revenue to meet the revenue requirement associated with its investment. Staff may be confusing the term of the Escrow Agreement, which is five years, with the term of the take-or-pay minimum, resulting in inaccurate conclusions of the financial impact of EnergyNorth's investment in this project. If iNATGAS fails to pay, or is in default after the retirement

[4] The Commission granted the parties' request to extend the Service Commencement Date to December 1, 2016. Order No. 26,002 (Apr. 6, 2017).

of the Escrow Agreement, EnergyNorth would seek recovery of the minimum amount through any, and all, enforcement options contained within the contract.

Q. Are there other inaccuracies contained in Staff's testimony you would like to address?

A. Yes. Staff mischaracterized the cost overruns regarding this project. Beginning on Bates 000019, Line 27, Staff asserted that the project was "over budget" by $2,570,594:

> Liberty's projected cost to serve iNATGAS was $2,245,000 compared to an actual capital cost of $4,815,594. Actual costs exceed projected costs by $2,570,594 as seen in the table below:

Liberty Capital Investment to Serve iNATGAS			
	Project	Actual	Over
Compressors	$1,000,000	$1,100,000	$100,000
Piping, meter set, survey, etc	$865,000	$3,080,084	$2,215,084
Land (pro-rated)	$200,000	$200,000	$0
Contingency	$180,000		($180,000)
AFUDC		$435,510	$435,510
Total	$2,245,000	$4,815,594	$2,570,594

Q. How is this statement and table a mischaracterization?

A. Staff overstated by $435,510 the amount that the project exceeded the initial projected cost. The project estimate of $2,245,000, as with all projects, only included the estimated "direct" costs, but excluded AFUDC, Overheads, and Burdens. The $4,815,594 is the "fully loaded" cost of the project, which includes the direct costs plus AFUDC, Overheads, and Burdens. Staff was made aware of this during a Technical Session held on November 1, 2017. The comparison should have been between the projected direct costs of $2,245,000, and the actual direct costs of the iNATGAS project, which was $4,380,084. This represents a difference of $435,510 from Staff's characterization, and should change Staff's "Total" in the "Over" column above to $2,135,084.

Q. Please explain the major drivers which accounted for the $2,135,084 cost increase of the iNATGAS project?

A. The first major driver was the decision by EnergyNorth to construct a "full capacity" facility. The original $2,245,000 estimate was for the first phase of construction, which would not accommodate the accelerated growth model beginning in years 4 and 5. In order to meet that higher throughput demand in later years, EnergyNorth would have had to invest more capital into the expansion of the facility at that time. This expansion would require additional paving, concrete work, a larger canopy and building, a larger or additional gas dryer, and compressors. The need for additional construction to accommodate the higher growth was communicated to Staff several years ago in the Company's response to Request No. Staff 2-8 in Docket No. DG 14-091 (Attachment WJC/SRH-5). As shown in that response, EnergyNorth's portion of the expansion was estimated at approximately $600,000 to $700,000 in direct costs. Adding $700,000 to the original estimate of direct cost would bring the total estimated direct cost up to $2,945,000.[5]

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[5] The Company notes that it provided an interim update of the status of construction and the costs incurred to that point during the October 23, 2015, hearing in the 2015-2016 Winter Cost of Gas proceeding, Docket No. DG 13-353. *See* the transcript of that hearing at page 15, et seq.: http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-353/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/15-353%202015-10-26%20TRANSCRIPT%20OF%20HEARING%20HELD%20ON%2010-23-15.PDF

Q. Has this work been completed?

A. Yes, EnergyNorth has completed this work which includes all asphalt and concrete work, a larger canopy and compressor building, as well as gas conditioning equipment. iNATGAS will still need to install components, at its expense, to make the facility operate at full capacity. Staff performed a walk-through of the completed facility in the fall of 2017, during which the Company discussed this incremental investment.

Q. Why did EnergyNorth decide to construct to the accelerated model at that time?

A. The timing of the decision was shortly after the Polar Vortex winter of 2014 – 2015, when spot prices of natural gas had soared and oil and propane prices were extremely high. The iNATGAS facility would have been the only CNG facility in the Northeast with firm capacity on an interstate pipeline that could have provided customers with a cost effective option to the high prices of oil and propane, without the need to purchase spot gas. In addition, large CNG providers like XNG and NG Advantage were announcing new customers quite frequently. The Company believed the cost savings associated with completing all the work for the full capacity facility from the onset was a prudent business decision, based on what was known at the time of the decision.

Q. Was there another factor which contributed to the increased project cost?

A. Yes. At the time of the iNATGAS project, EnergyNorth was also in the process of constructing the Training Center on Broken Bridge Road. EnergyNorth had been discussing both projects with the City of Concord. *After* the Order approving the Special Contract and Lease with iNATGAS was issued, the City imposed new conditions on the project. The City required EnergyNorth to install a new water line from the top of Broken Bridge Road to the driveway of EnergyNorth's LNG facility (approximately 2,500 feet), and required reconstruction and repaving the entire length of Broken Bridge Road to the end of the public road, along with construction of a public turnaround point (a slightly longer distance). EnergyNorth was not told of these requirements until construction contracts for the iNATGAS facility were executed. The cost for this incremental work, which was allocated to the iNATGAS project, was approximately $600,000. Although the Company does business in Concord, these costs were not anticipated since Broken Bridge Road is a dead end road, and the Company will be responsible for any future road improvements necessitated by the facility. Adding this cost brings the project's total direct cost to approximately $3,545,000.

Q. Please explain the remaining difference in direct costs which account for the project being in excess of the original budget.

A. The remaining balance of $835,084, is approximately 20%, of the final direct cost of the project. After discussions with the Company's engineering consultant, EnergyNorth moved forward with design changes that the Company determined would better protect its investment and optimize facility run time, which could enhance distribution revenues. These changes included housing the compressors and control systems within a full, 3-sided building, rather than beneath a canopy, and the construction of roof protections over the meters and regulators and additional equipment behind the compressor building. EnergyNorth owns the existing four compressors along with the meters and regulators, which cost in excess of $1.3 million. If this equipment were damaged or destroyed due to acts of nature, the Company would be responsible for repair and/or replacement. The building and roof protections should also result in more available run time for the facility due to the increased reliability and service associated with protection from the elements. These change orders accounted for approximately $200,000. The remaining balance of costs in excess of the original estimate ($635,084) was primarily due to higher costs for asphalt and concrete work, as well as other minor design changes.

Q. What is the current utilization status of the facility and iNATGAS contract projections?

A. iNATGAS executed a contract with a large customer who began utilizing the facility in early December 2017. The monthly consumption for December, including several days of testing, was close to 20,000 Mcf (which would equate to 80% of the minimum take or pay). The Company has been informed by iNATGAS that they are in negotiations with this customer to expand the usage of the facility significantly through a multi-year contract. Capital investments required to accommodate this expansion would be iNATGAS's responsibility.

Q. Are there other benefits associated with this project for EnergyNorth's customers other than distribution revenues and rent?

A. Yes. EnergyNorth's customers will see a benefit in the form of capacity cost savings associated with iNATGAS's peak day. To date, iNATGAS has a peak day of 1,826 Mcf, which would meet their capacity assignment even if they didn't increase load any further. Capacity benefits were discussed during the proceedings, but were not included in the financial analysis. In the response to Request No. Staff 3-10 in Docket No. DG 14-091 (Attachment WJC/SRH-6), Mr. DaFonte calculated an Annual Capacity Credit for all EnergyNorth customers based upon varying Peak Day metrics. If the current Peak Day of 1,826 Mcf were utilized for this calculation, it would result in an Annual Capacity Credit for all customers of over $300,000, which has not been taken into account in the analysis of the economics of the project.

Q. Do you believe the iNATGAS facility to be a prudent investment and allowed in EnergyNorth's rate base for full recovery?

A. Yes, for reasons stated above we believe full recovery of the $4,815,594 should be allowed. Not only did the Company make prudent decisions related to the cost of constructing the facility as that process evolved, but current information is now proving that the project is clearly economic using a traditional DCF analysis, even at a cost in excess of the original estimate, and will result in benefits to customers.

Q. Does this complete your testimony?

A. Yes, it does.