STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 20-105

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

DIRECT TESTIMONY

OF

STEVEN E. MULLEN

July 31, 2020

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I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

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

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

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

Q. Please state your professional experience and educational background.

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

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

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

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

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

Q. What is the purpose of your testimony?

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

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

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

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

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

II. <u>REASONS FOR RATE CASE FILING</u>

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

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

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

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

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

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

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

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

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

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

[2] Order No. 26,266 at 7.

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

III. REQUEST FOR STEP ADJUSTMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. No. The law states as follows:

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

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

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

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

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

A. Yes.

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

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

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

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

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

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

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

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

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

IV. FOLLOW-UP ITEMS FROM PRIOR DOCKETS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Has the required analysis been prepared?

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

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

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

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

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

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

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

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

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

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

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

Q. Has that analysis been performed?

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

Q. What were the results of that analysis?

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

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

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

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

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

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

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

1) the amount of revenue collected or passed back through this mechanism, by year;
2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs;
3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes;
4) an account of efforts taken to educate builders about energy efficiency;
5) a detailed list of meetings with state and local officials and associations to promote energy efficiency;
6) customer feedback resulting from decoupling as implemented through the rate design; and
7) any changes in the Company's credit rating.

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

Q. Please discuss each of the above items.

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

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

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

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

Table 1

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

V. DUE DATES FOR RATE AND OTHER FILINGS

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

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

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

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

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

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

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

VI. CUSTOMER SERVICE INITIATIVE

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

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

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

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

Q. How would this work?

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

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

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

Q. Does this conclude your testimony?

A. Yes, it does.