REDACTED

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 19-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Winter 2019/2020 Cost of Gas Filing
Summer 2020 Cost of Gas Filing

DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

September 3, 2019

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I. INTRODUCTION

Q. Please state your full name and business address.

A. (DS) My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

(CM) My name is Catherine A. McNamara. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("Liberty"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

Q. Please describe your educational background and your business and professional experience.

A. (DS) I graduated from Ferris State University in 1993 with a Bachelor of Science in Finance. I received a Master's of Science in Finance from Walsh College in 2000. I also received a Master's of Business Administration from Walsh College in 2001. In 2006, I earned a Graduate Certificate in Power Systems Management from Worcester Polytechnic Institute. In August 2013, I joined Liberty as a Utility Analyst and I was promoted to Manager, Rates and Regulatory Affairs in August 2017. Prior to my employment at Liberty, I was employed by NSTAR Electric & Gas ("NSTAR") as a Senior Analyst in Energy Supply from 2008 to 2012. Prior to my position in Energy

Supply at NSTAR, I was a Senior Financial Analyst within the NSTAR Investment Planning group from 2004 to 2008.

(CM) I graduated from the University of Massachusetts, Boston, in 1993 with a Bachelor of Science in Management with a concentration in Accounting. In November 2017, I joined Liberty as an Analyst in Rates and Regulatory Affairs. Prior to my employment at Liberty, I was employed by Eversource as a Senior Analyst in the Investment Planning group from 2015 to 2017. From 2008 to 2015, I was a Supervisor in the Plant Accounting department. Prior to my position in Plant Accounting, I was a Financial Analyst/General Ledger System Administrator within the Accounting group from 2000 to 2008.

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

A. (DS) Yes. I have testified on numerous occasions before the Commission.

(CM) Yes. I have testified on multiple occasions before the Commission.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's proposed firm sales cost of gas rates for the 2019/2020 Winter (Peak) Period and the Company's proposed 2019/2020 Local Delivery Adjustment Clause, both effective November 1, 2019. Our testimony also explains the Company's proposed firm sales cost of gas rates for the 2020 Summer (Off-Peak) Period.

II. WINTER 2019/2020 COST OF GAS FACTOR

Q. What are the proposed firm Winter sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.6203 per therm for residential customers, $0.6190 per therm for commercial/industrial high winter use customers, and $0.6258 per therm for commercial/industrial low winter use customers as shown on Proposed Sixth Revised Page 92 (Bates 049). The Company proposes a firm transportation cost of gas rate of $0.0009 per therm as shown on Proposed Third Revised Page 94 (Bates 051).

Q. Please explain tariff page and Proposed Sixth Revised Page 92 (Bates 049).

A. Proposed Sixth Revised Page 92 contains the calculation of the 2019/2020 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 92, the proposed 2019/2020 Average Cost of Gas of $0.6203 per therm is derived by adding the Direct Cost of Gas Rate of $0.5947 per therm to the Indirect Cost of Gas Rate of $0.0256 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Page 92, is $52,211,274. The estimated Indirect Cost of Gas, also derived on Page 92, is $2,251,330. The Direct Cost of Gas Rate of $0.5947 and the Indirect Cost of Gas Rate of $0.0256 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 87,788,508 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 92.1 (Bates 050), total $275,601. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $51,935,672 to determine the Total Anticipated Direct Cost of Gas of $52,211,274.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Original Page 92.1 consists of the following components:

1.	Purchased Gas Demand Costs	$10,157,458
2.	Purchased Gas Commodity Costs	34,260,417
3.	Storage Demand and Capacity Costs	902,742
4.	Storage Commodity Costs	4,281,375
5.	Produced Gas Cost	2,333,680
	Total	$51,935,672

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Original Page 92.1, are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$1,912,210
2.	Interest	(81,952)
3.	Fuel Inventory Revenue Requirement	351,641
4.	Broker Revenues	(30,924)
5.	Transportation COG Revenue	(44,891)
6.	Capacity Release Margin	(1,875,483)
7.	Fixed Price Administrative Cost	45,000
	Total Adjustments	$275,601

These allowable adjustments are standard adjustments made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. We discuss the factors contributing to the prior period under collection later in this testimony.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in Docket No. DG 18-137 for the 2018/2019 Winter Period?

A. The average cost of gas rate proposed in this filing of $0.6203 per therm is $0.1208 per therm less than the initial rate of $0.7411 per therm approved by the Commission in Order No. 26,188 (November 1, 2018) in Docket No. DG 18-137. The $0.1208 per therm decrease in the rate reflects an $8,411,494 decrease in the Total Unadjusted Direct Cost of Gas Cost of Gas.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2018/2019 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0009 per therm (Bates 051). The rate approved in Docket No. DG 18-137 was $0.0005 per therm. The increase in the rate relates primarily to an estimated $30,335 increase in costs due to the difference between the winter season 2018/2019 beginning balance of $59,496 (an over-collection) and the winter season 2019/2020 beginning balance of $29,161 (an over-collection).

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. No. The Company used, for pressure support purposes, a rate of 8.7% based on the marginal cost study used for the rate design approved in Docket No. DG 17-048.

Q. Did the Company include a fuel inventory revenue requirement calculation in this filing?

A. Yes (Bates 199). The Company is proposing to collect $351,641 in fuel inventory revenue requirement consistent with Order No. 26,156 (July 10, 2018) in Docket No. DG 17-048. The impact of this amount to the overall Cost of Gas rate is $0.0040 per therm which is determined by dividing the $351,641 by the estimated November 2019 through October 2020 COG sales volumes of 87,788,508 therms.

Q. How was the statutory tax rate of 27.08% calculated (Bates 199)?

A. The statutory rate of 27.08% was calculated by using a 21% federal tax rate and a 7.7% tax rate for the State of New Hampshire (0.21 + 0.077 – (0.21 x 0.077) = 0.27083).

Q. How was the common equity pre-tax rate of 6.280% calculated (Bates 199)?

A. The common equity pre-tax rate of 6.280% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 17-048, by 0.72917 (1 – 0.27083) [statutory tax rate – see previous question]) and multiplied by 49.20% (equity component of the capital structure approved in DG 17-048) [0.093 / 0.72917 x 0.4920 = 0.0628].

Q. Has the bad debt percentage in this filing of 1.11% changed from the bad debt percentage calculated in the Winter 2018/2019 Cost of Gas Reconciliation?

A. Yes, the bad debt percentage of 1.11% used in this filing is the calculated rate for the period of May 2018–April 2019. This is a $0.59 decrease from the calculated rate filed in the Winter 2018/2019 COG filing of 1.70%.

Q. What was the actual weighted average firm sales cost of gas rate for the 2018/2019 winter period?

A. The weighted average cost of gas rate was $0.6633 per therm (Bates 092 Line 54). This was calculated by applying the actual monthly cost of gas rates for November 2018 through April 2019 to the monthly therm usage of an average residential heating customer using 809 therms per year, or 666 therms for the six winter period months.

III. PRIOR WINTER PERIOD UNDER-COLLECTION

Q. Please explain the prior period under collection of $1,912,210.

A. The prior period under-collection is detailed in the 2018/2019 Winter Period Reconciliation that was filed with the Commission on August 22, 2019. The $1,912,210 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2019. The under-collection was driven mainly by the lag in the timing of monthly cost of gas rate adjustments as compared to changes in the underlying costs.

IV. FIXED PRICE OPTION

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?

A. Yes. Pursuant to Order No. 24,515 in Docket No. DG 05-127, the Fixed Price Option Program ("FPO") rates are set at $0.0200 per therm higher than the initial proposed COG rate. Proposed Second Revised Page 91 (Bates 048) contains the FPO rate for the 2019/2020 Winter period, which is $0.6403 per therm for residential customers. This compares to the FPO rate approved for the 2018/2019 winter period of $0.7611 per therm for residential customers. This represents a $0.1208 per therm, or 15.8% decrease in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 666 therms is a decrease of approximately $82.11 or 16.2% compared to last winter. The total bill impact reflects the overall rates in effect following implementation of the increases approved in Docket No. DG 19-054, effective July 1, 2019, relating to the cast iron/bare steel main replacement program. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $13.32 (or 1.45%) higher than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 (Bates 196) contains the historical results of the FPO program.

V. LOCAL DELIVERY ADJUSTMENT CLAUSE ("LDAC")

Q. What are the surcharges that will be billed under the LDAC?

A. As shown on Proposed Second Revised Page 97 (Bates 054), the Company is submitting for approval an LDAC of $0.0635 per therm for the residential non-heating class and residential heating class, and $0.0494 per therm for the commercial/industrial bundled sales classes, effective November 1, 2019. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Factor, the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Low Income Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 17-048.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2019, through October 31, 2020, forecasted Keene therm sales of 1,542,677 are added to the EnergyNorth therm sales forecast of 185,636,009 for a total therm sales forecast of 187,178,686 (slightly off due to rounding).

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2019 that will be filed with the Commission in the near future. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period under-recovery of the Company's residential and commercial energy efficiency programs as of October 2019. As shown on Schedule 19 Energy Efficiency (Bates 132-134), the proposed Energy Efficiency charge is $0.0640 per therm for Residential customers and $0.0426 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Factor ("RDAF").

A. This is the initial calculation of the RDAF since the implementation of decoupling on November 1, 2019. The purpose of the RDAF is to recover or refund, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. While in the process of preparing the necessary calculations, it was discovered that with respect to low-income customers the formulas approved in the

Company's tariff to calculate the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer do not use the same basis between the two formulas to calculate the revenue per customer. The approved Benchmark Base Revenue per Customer calculation uses low income residential heating revenue (rate R-4) in the calculation while the Actual Base Revenue per Customer calculation uses the residential heating rate (rate R-3) to calculate the rate R-4 revenue. In other words, the formulas in the tariff use the R-4 rate to calculate the benchmark R-4 revenue per customer and use the R-3 rate to calculate the actual R-4 revenue per customer. Schedule 19 RDAF (Bates 118-123) shows the proposed Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation of a total over-collection of $4,691,932 effective November 1, 2019, through October 31, 2020. In that calculation, the Company has aligned the Base Revenue per Customer and Benchmark Revenue per Customer calculations related to low income customers. Schedule 19 RDAF (Bates 124–129) shows the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation reflecting the current language in the tariff, which results in a total over-collection of $6,642,895 effective November 1, 2019, through October 31, 2020, based on the formulas in the Company's tariff.

Q. What would be the effect of using the calculation based on the current tariff language?

A. The net effect would be that the dollars collected to recover the costs of the low-income program would effectively be returned to customers through the RDAF mechanism.

Q. Please explain the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism ("LRAM").

A. As shown on Schedule 19 LRAM (Bates 116–117), the proposed LRAM charge is $0.0001 per therm for residential customers and $0.0001 per therm for commercial and industrial customers. It is designed to recover lost revenues associated with energy efficiency measures installed under the EERS programs. Since the Company implemented decoupling effective November 1, 2019, the Company will continue to implement its Lost Revenue Adjustment only as a prior period true-up mechanism effective November 1, 2019, and ending October 31, 2020.

Q. What is the proposed Residential Low Income Assistance Program ("RLIAP") charge?

A. As shown on Schedule 19 RLIAP (Bates 130–131), the proposed RLIAP charge is $0.0123 per therm. It is designed to recover administrative costs, revenue shortfall, and the prior period reconciliation adjustment relating to this program. For the 2019/2020 Winter Period, the Company is providing a 60% base rate discount, consistent with the settlement agreement approved by the Commission in Order No. 24,669 (Sept. 22, 2006) in Docket No. DG 06-120. The proposed RLIAP charge is designed to recover $2,307,356, of which $1,861,760 is for the revenue shortfall resulting from 5,932 customers receiving a 60% discount off their base rates, and $445,596 for the prior year reconciling adjustment.

Q. In Order No. 24,824 (Feb. 29, 2008) in Docket No. DG 06-122 relating to short-term debt issues, the Company agreed to adjust its short-term debt limits each year as part of the Company's Winter Period Cost of Gas filing. Did the Company calculate the short-term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Schedule 24 (Bates 197) the short-term debt limit for fuel and non-fuel purposes for the 2019/20 period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2019, through October 31, 2020, is calculated to be $16,338,781 and the limit for non-fuel purposes is calculated to be $99,644,640.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 95)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism, as well as the third party recoveries, are included in the Environmental Cost Summary in Schedule 20 (Bates 135) of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Casey in her pre-filed direct testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Schedule 20. The Summary included in Schedule 20 shows the remediation cost pools for the Concord Pond, Concord MGP, Manchester, Nashua, and Laconia sites, and a General Pool for costs that cannot be directly assigned to a specific site.

A summary sheet and detailed backup spreadsheets that support the 2018/2019 costs are provided in Schedule 20 of this filing. Ms. Casey's testimony describes the Company's activities with regard to all five sites.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2019, and ending October 31, 2020, is $0.0153 per therm. Consistent with filings made over the past few years, this surcharge will recover a total of $2,860,522 in amortized remediation costs. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing. This surcharge has not included recovery of any beginning balance transferred over from National Grid when the Company was acquired by Liberty Energy Utilities Corp. in Docket No. DG 11-040 nor has the surcharge included any actual to forecast true-up refund or recovery since the acquisition as provided for in the Company's tariff. The Company is planning to submit an environmental reconciliation to PUC audit staff for review and opinion by January 15, 2020. Audit Staff findings will be addressed in the Winter 2020/2021 COG filing.

Q. Did the Company include a Rate Case Expense (RCE) surcharge in this filing?

A. Yes. As shown on Schedule 19 RCE (Bates 114–115), the Company is proposing to collect $309,225 in uncollected rate case and recoupment expense consistent with Order No. 26,122 (April 27, 2018) in Docket No. DG 17-048. The RCE rate of $0.0017 per therm is determined by dividing the $309,225 by the estimated November 2019 through October 2020 sales volumes of 187,178,686 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2019 through October 2020 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 198) the Company has recalculated its Company Allowance for the period November 2019 through October 2020. The Company calculated the Company Allowance of 1.92% based on sendout and throughput data for the twelve-month period ending June 2019. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2019.

VI. CUSTOMER BILL IMPACTS

Q. What are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's winter bill as compared to the winter rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 (Bates 092) of this filing. These bill impacts reflect the implementation of the increases approved in Docket No. DG 19-054 effective July 1, 2019, relating to the cast iron/bare steel main replacement program. The total bill impact over the winter period for an average residential heating customer is a decrease of approximately $24.76 or 2.6%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is a decrease of approximately

$129.12, or 5.2% (Bates 093). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed Second Revised Page 147 (Bates 055) relating to Supplier Balancing and Peaking Demand Charges and Proposed Second Revised Page 148 (Bates 056) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 147.

A. In Proposed Second Revised Page 147, the Company is updating the Peaking Demand Charge from $20.41 per MMBtu of Peak MDQ to $18.12 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 187).

Q. Please describe the changes to tariff Page 148.

A. Proposed Second Revised Page 148 updates the Capacity Allocator percentages used to allocate pipeline, storage, and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 (Bates 190–195) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2020 COST OF GAS FACTOR

Q. What are the proposed 2020 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.4520 per therm for residential customers, $0.4474 per therm for commercial/industrial high winter use customers, and $0.4591 per therm for commercial/industrial low winter use customers as shown on Proposed Eighth Revised Page 89 (Bates 205).

Q. Please explain tariff pages Proposed Third Revised Page 88 and Proposed Ninth Revised Page 89.

A. Proposed Third Revised Page 88 (Bates 204) and Proposed Ninth Revised Page 89 contain the calculation of the 2020 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed Ninth Revised Page 89, the 2020 Average Cost of Gas of $0.4520 per therm is derived by adding the Direct Cost of Gas Rate of $0.4603 per therm to the Indirect Cost of Gas Rate of ($0.0083) per therm. The estimated total Anticipated Direct Cost of gas is $9,653,380 and the estimated Indirect Cost of Gas is ($174,652). The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected Summer firm sales volumes of 20,973,031 therms. Proposed Ninth Revised Page 89 further shows that the Residential Cost of Gas Rate of $0.4520 per therm is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial High Winter Use Cost of Gas Rate of $0.4474 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.4591 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed Third Revised Page 88. To derive the total Anticipated Direct Cost of Gas of $9,653,380, the Company starts with the Unadjusted Anticipated Cost of Gas of $7,685,193 and adds the Net Adjustment totaling $1,968,188.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1. Purchased Gas Demand Costs	$4,548,346
2. Purchased Gas Supply Costs	3,114,165
3. Produced Gas Costs	22,682
Total Unadjusted Anticipated Cost of Gas	$7,685,193

Q. What are the components of the adjustments to the cost of gas?

A. The adjustments to gas costs, listed on proposed Third Revised Page 88, are as follows:

1. Prior Period (Over)/Under Collection	$1,885,446
2. Interest	82,742
Total Adjustments	$1,968,188

Q. How does the proposed average Residential Summer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2020 Summer Period?

A. The cost of gas rate proposed in this filing is $0.0075 per therm higher than the initial rate approved by the Commission for the 2019 Summer Period ($0.4445 vs. $0.4520)

(Schedule 8, Bates 228). This increase is primarily due to a $1,268,403 estimated under-collection increase compared to the under-collection from the prior summer period.

Q. Does this conclude your testimony?

A. Yes, it does.