Liberty Utilities

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 15-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Winter 2015/2016 Cost of Gas Filing

DIRECT TESTIMONY

OF

DAVID B. SIMEK

August 28, 2015

I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire 03053.

Q. Please state by whom you are employed and your position.

A. I am a Lead Utility Analyst for Liberty Utilities Service Corp. ("Liberty") which provides services to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company"). I am responsible for providing rate-related services for the Company.

Q. Please describe your educational background and training.

A. 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.

Q. What is your professional background?

A. In August 2013, I joined Liberty Utilities as a Utility Analyst and I was promoted to a Lead Utility Analyst in December 2014. Prior to my employment at Liberty Energy Utilities (New Hampshire) Corp., 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.

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

A. Yes. I recently provided written and oral testimony before the Commission in Docket Nos. DG 15-117, DG 15-104 and DG 15-091.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's proposed firm sales cost of gas rates for the 2015/16 Winter (Peak) Period and the Company's proposed 2015/16 Local Distribution Adjustment Charge, both effective beginning November 1, 2015.

II. <u>COST OF GAS FACTOR</u>

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

A. The Company proposes a firm sales cost of gas rate of $0.7516 per therm for residential customers, $0.7454 per therm for commercial/industrial high winter use customers and $0.7647 per therm for commercial/industrial low winter use customers as shown on Proposed First Revised Page 77. The Company proposes a firm transportation cost of gas rate of ($0.0007) per therm as shown on Proposed First Revised Page 79.

Q. Would you please explain tariff page Proposed First Revised Page 76 and Proposed Seventeenth Revised Page 77?

A. Proposed First Revised Page 76 and Proposed First Revised Page 77 contain the calculation of the 2015/16 Winter Period Cost of Gas Rate and summarize the Company’s forecast of firm gas costs and firm gas sales. As shown on Page 77, the proposed 2015/16 Average Cost of Gas of $0.7516 per therm is derived by adding the Direct Cost of Gas Rate of $0.6930 per therm to the Indirect Cost of Gas Rate of $0.0586 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 76 and repeated on Page 77, is $59,426,348. The estimated Indirect Cost of Gas, also derived on Page 76 and repeated on Page 77, is $5,026,252. The Direct Cost of Gas Rate of $0.6930 and the Indirect Cost of Gas Rate of $0.0586 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 85,749,300 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 76, total ($10,184,020). These adjustments are added to the Unadjusted Anticipated Cost of Gas of $69,610,368 to determine the Total Anticipated Direct Cost of Gas of $59,426,348.

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

A. The Unadjusted Anticipated Cost of Gas shown on Proposed First Revised Page 76 consists of the following components:

1.	Purchased Gas Demand Costs	$7,958,775
2.	Purchased Gas Commodity Costs	51,450,609
3.	Storage Demand and Capacity Costs	987,267
4.	Storage Commodity Costs	5,489,978
5.	Produced Gas Cost	3,547,477
6.	Hedge Contract Loss/(Savings)	176,262
	Total	$69,610,368

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

A. The allowable adjustments to gas costs, listed on Proposed First Revised Page 76 are as follows:

1.	Prior Period Over Collection	($4,339,198)
2.	Interest	(140,799)
3.	Broker Revenues	(1,917,919)
4.	Refund from Suppliers	(358,691)
5.	Transportation COG Revenue	35,761
6.	Capacity Release Margin	(3,512,739)
7.	Fixed Price Administrative Cost	49,565
	Total Adjustments	($10,184,020)

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. I will discuss the factors contributing to the prior period over 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 14-220 for the 2014/15 Winter Period?

A. The average cost of gas rate proposed in this filing is $0.4114 per therm lower than the initial rate of $1.1630[1] approved by the Commission in Order No. 25,730 dated October 31, 2014, in Docket No. DG 14-220. The decrease in the rate reflects a decrease in the total cost of gas of approximately $24.1 million or 27.2% ($26.5 million decrease in total direct gas costs and a $2.4 million increase in indirect gas costs). The $26.5 million decrease in the total direct cost of gas is a result of a $4.5 million decrease in commodity costs, a $0.5 million decrease in demand costs and a $21.5 million decrease in adjustments.

The $4.5 million decrease in commodity costs is due to a $0.5 million decrease in pipeline commodity costs and a $4.0 million decrease in supplemental costs

1 For comparison purposes, by the end of the 2014/15 Winter Period, the residential cost of gas rate decreased to $0.6455 per therm through the operation of the monthly adjustment mechanism.

(underground storage, LNG, and propane). The $4.0 million decrease in supplemental costs is due to lower commodity prices. The $21.5 million decrease in adjustments is primarily due to the Company having a under collection balance of $14.9 million at the beginning of the 2014/15 winter period compared to an over collection balance of $4.3 million at the beginning of the 2015/16 winter period. Increased broker revenues and capacity release margins also contributed to the adjustments decrease.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2014/15 winter period?

A. The proposed firm transportation winter cost of gas rate is ($0.0007) per therm. The rate approved in Docket No. DG 14-220 was $0.0079. The decrease in the rate relates to an estimated $127,000 in transportation customer costs offset by the prior period over collection of $162,345.

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, it has not. The Company used, for pressure support purposes, a rate of 9.9% based on the marginal cost study used for the rate design approved in the Settlement Agreement in Docket No. DG 10-017.

Q. Schedule 25 shows an lost and unaccounted for gas percentage ("LAUFG%") of 1.56%. Was that the percentage used in the Total Firm Volumes calculation in Schedule 1?

A. Yes. Although page 21 of the Settlement Agreement in Docket No. DG 11-040 included a cap on the LAUFG% of 1.28%, the 1.28% cap was only in place until June 30, 2015. In order for the Company to properly estimate Total Firm Volumes, the unaccounted for gas calculation includes the actual LAUFG%.

Q. What was the actual weighted average firm sales cost of gas rate for the 2014/15 winter period?

A. The weighted average cost of gas rate was $0.9541 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2014 through April 2015 to the monthly therm usage of an average residential heating customer using 776 therms per year, or 623 therms for the six winter period months.

III. PRIOR PERIOD OVER COLLECTION

Q. Please explain the prior period over collection of $3,646,670.

A. The prior period over collection is also detailed in the 2014/15 Winter Period Reconciliation that was filed with the Commission on July 29, 2015. The $3,646,670 over collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2015, including Peak Period costs recovered in May 2015 based on billings for April consumption. The over collection is primarily due to the sharp decrease in gas prices in Tennessee's Zone 6 market area, declining NYMEX prices and lower basis in the Marcellus and Utica shale production areas.

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 First Revised Page 78 contains the FPO rate for the 2015/16 Winter period, which is $0.7716 per therm for residential customers. These compare to FPO rates approved for the 2014/15 winter period of $1.2425 per therm for residential customers. This represents a $0.4709 per therm, or 37.9% decrease in the residential FPO rate. The impact on the winter period bills for an average heating customer using 623 therms is a decrease of approximately $240 or 21% compared to last winter. The bill impact reflects the implementation of the increases approved in Docket Nos. DG 14-180 and DG 15-104 effective July 1, 2015, relating to permanent distribution rate increases and 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 $12 (or 1.0%) 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 contains the historical results of the FPO program.

V. HEDGED SUPPLIES

Q. Has the Company hedged any of its winter period supplies pursuant to its proposed Natural Gas Price Risk Management Plan?

A. Yes, it has. As shown in Schedule 7, page 2, the Company has hedged a total of 134,214 Dekatherms (1.3 million therms) at a weighted average fixed price of $4.4511 per Dekatherm. The hedged price reflects the higher cost of gas during the period that the hedged volumes were locked in.

Q. On what dates and at what prices did the Company contract for these supplies?

A. The Company has three contracts that hedge the price of gas supplies for the 2015/16 Winter Period with prices ranging from $4.0500 to $4.5550 per Dekatherm. The contracts date from June 18, 2014, through July 18, 2014. The contract dates, volumes and prices are listed in Schedule 7, pages 2 through 4.

VI. LOCAL DISTRIBUTION ADJUSTMENT CHARGE ("LDAC")

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

A. As shown on Proposed First Revised Page 82, the Company is submitting for approval an LDAC of $0.1014 per therm for the residential non-heating class and residential heating class, and $0.0685 per therm for the commercial/industrial bundled sales classes. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, Rate Case Expense Recovery, and the Residential Low Income Assistance Program charge.

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 2016 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 over recovery of the Company's Residential and Commercial energy efficiency programs as of October 2015. As shown on Schedule 19 Energy Efficiency, the proposed Energy Efficiency charge is $0.0585 per therm for Residential customers and $0.0256 per therm for Commercial and Industrial customers.

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

A. As shown on Schedule 19 RLIAP, the proposed RLIAP charge is $0.0145 per therm. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this program. For the 2015/16 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 in Docket No. DG 06-120. The current RLIAP charge is designed to recover $2,674,553, of which $2,518,737 is for the revenue shortfall resulting from 8,142 customers receiving a 60% discount off their base rates, and $155,815 is for the prior year reconciling adjustment.

Q. In Order No. 24,824 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 the short-term debt limit for fuel and non-fuel purposes for the 2015/16 period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2015, through October 31, 2016, is calculated to be $19,335,780 and the limit for non-fuel purposes is calculated to be $73,871,505.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 80)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism as well as the third party recoveries are presented in the Environmental Cost Summary included in Schedule 20 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, Manchester, Nashua, Dover, Laconia, and Keene 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 2015/16 costs are provided in Schedule 20 of this filing. Consistent with past practice, the Company met with the Commission Staff and OCA in August of this year to update them on the status of environmental matters. Ms. Casey's testimony describes the Company's activities with regard to all six sites.

Q. In Docket No. DG 12-265, the Company indicated that approximately $79,000 of environmental costs had been embedded in the approved base rate tariffs. How did the Company reflect those revenues in its calculation of its Environmental Surcharge?

A. For the period June 2010 through October 2015, the Company had modified its Environmental Cost Summary on Schedule 20 to reduce the recoverable environmental costs by the base rate recoveries of certain labor costs. As a result of the Settlement Agreement in Docket No. DG 14-180, such an adjustment is no longer necessary.

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, 2015, and ending October 31, 2016, is $0.0144 per therm. This surcharge will recover a total of $2,651,933 in amortized remediation costs. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing.

Q. Does the LDAC include a credit for Interruptible Transportation Margins?

A. No, the Interruptible Transportation Service rate has been eliminated based on the Settlement Agreement in Docket No. DG 14-180.

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

A. Yes. Consistent with the Settlement Agreement in Docket No. DG 14-180 and as shown on Schedule 19 RCE, the Company is proposing to collect $3,041,159 in estimated remaining rate case and recoupment expense over the next fourteen months. The RCE rate of $0.0140 per therm is determined by dividing the $3,041,159 by the estimated November 2015 through December 2016 sales volumes of 217,953,914 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2015 through October 2016 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 the Company has recalculated its Company Allowance for the period November 2015 through October 2016. The Company calculated the Company Allowance of 1.69% based on sendout and throughput data for the twelve-month period ending June 2015. This recalculated Company Allowance is proposed to be applied to all supplier deliveries beginning in November 2015.

VII. CUSTOMER BILL IMPACTS

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

A. The bill impact analysis is presented in Schedule 8 of this filing. These bill impacts reflect the implementation of the increases approved in Docket Nos DG 14-180 and DG 15-104 effective July 1, 2015, relating to permanent distribution rate increases and 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 $73, or 7.7%. The total bill impact for an average commercial/industrial G-41 customer is a decrease of approximately $300, or 11.4%. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VIII. OTHER TARIFF CHANGES

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

A. Yes. The Company is submitting Proposed First Revised Page 143 relating to Supplier Balancing and Peaking Demand Charges and Proposed First Revised Page 144 relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 143.

A. In Proposed First Revised Page 143, the Company is updating the Peaking Demand Charge from $18.22 per MMBtu of Peak MDQ to $12.89 per MMBtu of Peak MDQ, a $5.33 decrease. This calculation is also presented in Schedule 21.

Q. Please describe the changes to tariff Page 144.

A. Proposed First Revised Page 144 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 contains the six-page worksheet that backs up the calculations for the updated allocators.

Q. Would the Company like to discuss the possibility of having one annual cost of gas filing?

A. Yes, the Company would like to begin discussions on the possibility of having one annual cost of gas filing. Having one yearly cost of gas filing would reduce the administrative burden on all parties and would still provide for different winter and summer Cost of Gas rates. The Company believes that working together with Staff and the OCA it is possible to have an annual cost of gas filing plan approved by the Commission prior to the 2016/2017 winter cost of gas filing.

Q. Does this conclude your testimony?

A. Yes, it does.

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