Liberty Utilities

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

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

DIRECT TESTIMONY

OF

GREGG H. THERRIEN

April 28, 2017

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I. INTRODUCTION

Q. Please state your name, address and position.

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. My professional qualifications and experience have been provided in Attachment GHT/DECPL-11 to this testimony.

Q. Have you testified previously before the New Hampshire Public Utilities Commission ("PUC" or the "Commission)?

A. No, I have not.

Q. What is your responsibility in this proceeding?

A. In this proceeding, I am responsible for: (1) designing the Revenue Decoupling Mechanism (Decoupling Testimony of Gregg H. Therrien) and (2) together with Company Witness David Simek, developing the rate design (Joint Rate Design Testimony of David B. Simek and Gregg H. Therrien) for Liberty Utilities (EnergyNorth Natural Gas Corp.) d/b/a Liberty Utilities ("EnergyNorth", or "the Company").

II. SCOPE OF DECOUPLING TESTIMONY

Q. Please summarize the scope of your testimony concerning the Company's proposed Revenue Decoupling Mechanism ("RDM").

A. In this testimony, I will:

1) provide general background on RDMs, why they are necessary as part of a comprehensive energy efficiency program, and why traditional ratemaking is insufficient support for utility energy efficiency advocacy;

2) provide the results of our research on RDMs that have been implemented by gas Local Distribution Companies ("LDCs") throughout the U.S.;

3) describe the impact that EnergyNorth's Energy Efficiency ("EE") programs, customer self-funded conservation, and other external factors has had on the Company's throughput volumes and the effect on the Company's ability to earn a reasonable rate of return between rate cases;

4) describe my understanding of the recent energy efficiency settlement agreement in Docket No. DE 15-137, and how it recognizes the need to harmonize increased energy efficiency spending with appropriate changes in ratemaking; and

5) describe and explain the Company's proposed RDM, which will allow EnergyNorth to continue to be a forceful and active advocate for energy conservation efforts, without harming its ability to earn a reasonable return.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

In recent years, there has been a heightened focus on energy conservation efforts and policies that encourage conservation.[1] This interest in energy conservation has been attributed to environmental considerations and to a dramatic spike in energy prices that occurred in 2005 – 2006, and again in 2009. Although gas prices have dropped significantly since 2009, there has been price spikes in New Hampshire over the past three winters and the attention to gas conservation has continued.[2]

Since 2005, EnergyNorth has experienced a continuous decline in usage, as measured by Normalized Use per Customer ("NUPC"), in the Residential and Small Commercial and Industrial ("C&I") classes.[3] Continuing declines in the Residential Heating and Small C&I classes have been offset by increases in usage from the Large C&I customer classes. Despite EnergyNorth's overall customer usage remaining relatively flat over this time period, the Company has experienced significant year-to-year volatility in average use per customer.[4]

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[1] Heightened focus in New Hampshire on energy conservation efforts and enabling policies to encourage conservation are demonstrated in the following reports: (a) New Hampshire Independent Study of Energy Policy Issues (September 2011), prepared for the New Hampshire Public Utilities Commission by Vermont Energy Investment Corporation; (b) Increasing Energy Efficiency in New Hampshire: Realizing Our Potential, (November 2013), prepared for the New Hampshire Office of Energy and Planning by the Vermont Energy Investment Corporation; (c) New Hampshire 10-Year State Energy Strategy (September 2014), published by New Hampshire Office of Energy & Planning; and most recently (d) the Energy Efficiency Resource Standard Settlement Agreement (the "Settlement Agreement"), dated April 27, 2016, as approved in the New Hampshire Public Utilities Commission ("NHPUC") order in Docket No. DG 14-180 (dated August 2, 2016).

[2] On an annual basis, the average Cost of Gas charged by EnergyNorth to firm sales customers has decreased from $1.18 per therm to $0.72 per therm between December 2009 and August 2013, a decrease of 40 percent. Since 2013 prices have trended even lower, despite increasing winter volatility. As of December 2016, EnergyNorth firm sales average annual customer average Cost of Gas is $0.50 per therm.

[3] These classes account for approximately 66% of the Company's total firm throughput, based on 2016 normalized consumption.

[4] The volatility in EnergyNorth's 12-month rolling Total firm NUPC is demonstrated by the following trend in standard deviation (in therms):
2006-2009 = 31.66

EnergyNorth is not alone - most US gas distribution companies have been experiencing similar patterns of declining use[5], and have responded by implementing RDMs in 29 different states.

EnergyNorth proposes to implement rate design measures[6] that will "decouple" the traditional connections between the volume of gas that EnergyNorth delivers to its customers and its revenues and earnings.

The decoupling rate design measures that the Company is proposing:

– Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;

– Will comport with the State of New Hampshire's vision in its 2014 State Energy Strategy, which recognized that "[r]ealigning utility incentives to reward utilities for investing in efficiency is a necessary part of any effort to increase efficiency in New Hampshire"; [7]

2010-2013 = 14.95
2014-2016 = 21.48
These standard deviations indicate that volatility was highest during the 2006 – 2009 era of high gas prices, lowest post-shale supply influx, and increasing over the past three years as a result of the polar vortex and tight New England supplies. This is discussed in detail in Section IV. D. 3. of this testimony.

5 This trend was examined extensively by such organizations as the American Gas Association, which reported a trend in declining use per residential natural gas customer of 1 percent annually from 1980 to 2000, and accelerated thereafter. *See* An Economic Analysis of Consumer Response to Natural Gas Prices, by Frederick Joutz and Robert P. Trost, prepared for the AGA, March 2007.

6 Specifically, the Company's proposed RDM and the Company's rate design proposals, which increase the proportion of the Company's total distribution revenues that are derived from customer charge revenues.

7 New Hampshire 10-Year State Energy Strategy, published by the New Hampshire Office of Energy & Planning September 2014. Executive Summary, page ii.

- Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[8] by producing equitable ratemaking beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals, and enables full acceptance of the energy savings initiatives envisioned in the Settlement Agreement; and
- Will fix a flaw in the traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

III. OVERVIEW OF DECOUPLING

A. Introduction

Q. Please describe a revenue decoupling mechanism.

A. In general terms, an RDM breaks the link between the quantities that a utility delivers to its customers and that utility's revenues. By eliminating the link between customer consumption and Company earnings, decoupling removes the disincentive for utilities to promote conservation and energy efficiency programs. Companies that have implemented decoupling are no longer caught between promoting conservation (that reduce sales) and growing revenues (by increasing sales). Breaking the link between

[8] The "Settling Parties" as defined in the Settlement Agreement approved in Docket No. DG 15-137, dated August 2, 2016, include: Commission Staff, Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire dba / Eversource Energy; the New Hampshire Electric Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way home; the Conservation Law foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development finance Authority; and TRC Energy Services.

utility sales and revenues is the best way to promote conservation activities fully and freely. Other mechanisms that only compensate the utility for the costs of conservation programs, such as a Lost Revenue Adjustment Mechanism ("LRAM"), fall short.

Q. Why is a LRAM insufficient in promoting conservation programs?

A. Mechanisms such as the recently approved LRAM in New Hampshire only compensate for energy efficiency measures installed as a result of utility programs, and alone do not promote conservation behaviors. The American Council for an Energy Efficient Economy ("ACEEE"), a nonprofit, 501(c)(3) organization, whose stated mission is to "act(s) as a catalyst to advance energy efficiency policies, programs, technologies, investments, and behaviors"[9] states:

> "An LRAM alone will not fully incentivize efficiency nor remove the throughput incentive. While the lost revenue adjustment can help make a utility whole by compensating it for reduced energy sales associated with efficiency programs, it will do little to encourage investment in energy efficiency unless combined with other policy levers. In fact, our analyses indicate that having an LRAM policy itself is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than are found in states without an LRAM policy. Nor does LRAM reduce a utility's motivation to increase sales (although some states do have safety nets in place). To fully remove the throughput incentive, decoupling should be considered."[10]

9 *See* http://aceee.org/about-us.
10 "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms", June 2015, ACEEE Report U1503.

Q. How does a decoupling mechanism work?

A. RDMs generally adjust rates on a periodic basis (e.g. annually or seasonally) to “make up” the difference between a target revenue per customer, which would have been set in the most recent rate case, and actual revenue per customer. RDMs are symmetrical; the calculation can result in either a charge or credit depending on the actual revenue per customer. A rate adjustment credit will be included in customers’ bills in a future period when actual revenue per customer is greater than the target revenue per customer in a recently-completed period. Conversely, a rate adjustment charge will be included in customers’ bills when actual revenue per customer is less than the target revenue per customer.

Q. Why do utilities need decoupling?

A. Utilities are becoming increasingly responsible for managing and actively promoting customer conservation through the development and implementation of robust energy efficiency programs. All else being equal, these programs will result in lower NUPC. In addition, utility customers have become increasingly aware of energy use and have invested in energy efficiency measures with their own dollars. Further, appliance efficiency improvements and stricter building code requirements result in higher overall energy efficiencies when customer equipment and existing building stock are replaced. Lastly, other external factors such as economic factors, demographics, and weather trends can contribute to changes in consumption. While reduced energy usage is good for individual consumers and society as a whole, it does have a negative impact on a utility’s ability to earn its allowed rate of return under traditional ratemaking.

Q. Please elaborate on the utility earnings dilemma.

A. The Company's financial performance, all else being equal, is negatively affected by declining NUPC. Decoupling is an appropriate and increasingly common component of a well-designed and implemented demand-side management ("DSM") program. Decoupling is appropriate whenever a utility's rates are designed such that a decrease in sales volumes adversely affects the ability of the utility to earn a reasonable return on investment. According to the Regulatory Assistance Project ("RAP"):

> "Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers."[11]

Q. Why should policy-makers and customers support decoupling?

A. As discussed above, decoupling unlocks the utility's ability to enthusiastically support energy efficiency policy goals. Over time, decoupling mechanisms provide rate stability that results from the mechanism's symmetrical design.[12] Further, decoupling can protect customers from a utility recovering excess revenues that may result from colder than normal weather or from favorable economic conditions.

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[11] "Revenue Regulation and Decoupling: A Guide to Theory and Application", November 2016, page 26.

[12] RAP also recognizes this, stating, "Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable." Ibid, page 26.

B. <u>Support for Decoupling: Energy Efficiency Programs</u>

Q. Why is decoupling important for regulated utilities that offer energy efficiency programs?

A. The ACEEE best summarized the importance of decoupling for regulated utilities in its June 2014 Policy Brief titled "Utility Initiatives: Alternative Business Models and Incentive Mechanisms" where it stated that:

> "Under traditional rate-of-return regulation, utilities have an economic disincentive to provide programs to help their customers be more energy efficient. Because a utility's earnings are based on the total amount of capital invested and the amount of electricity sold, increased energy sales generally increase utility profits. Experience suggests that enacting regulatory reforms such as decoupling…help overcome those inherent disincentives regarding energy efficiency.'

Further, in its June 2015 Report titled "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms" [13] they state:

> "Creating a regulatory environment that incentivizes utilities to invest in efficiency is critical for programs to be successful, impactful, and long lasting. Doing so requires a mix of policy tools. In addition to energy efficiency targets, utilities need a business model that aligns their financial interests with energy efficiency, including program cost recovery, performance incentives that encourage utilities to achieve high levels of savings, and some policy mechanism to neutralize the throughput incentive. It is our opinion that decoupling is the best third leg of this stool. However, it is also clear that decoupling is not always an option for states for a variety of reasons. In such scenarios, LRAM can be a temporary solution, offering a mechanism to address the

[13] Report U1503.

> concern over lost revenues and, possibly, help make parties more comfortable with the idea of full decoupling in the future.

These ACEEE policy excerpts clearly show the need for, and evolution of, utility ratemaking that supports energy efficiency goals.

C. Support for Decoupling: Ratemaking

Q. Please describe and explain the structure of decoupling mechanisms.

A. RDMs calculate a surplus or shortfall between actual and allowed revenues. There are two common RDM structures: (a) revenue per customer ("RPC") RDMs and (b) total revenue RDMs. The primary difference between these two structures is the revenue "true up" calculation and the treatment of new customers. The RPC RDM revenue true up determines the revenue shortfall or surplus by (a) calculating the difference between the target RPC and actual current period RPC by customer group or rate class and (b) multiplying the difference per customer ("RDM per Customer Adjustment") by the current period number of customers. The effect of a RPC RDM is that the sum of actual rate class/rate group revenues per customer plus the RPC RDM per customer adjustment will always equal the target RPC, and total actual revenues will change in direct proportion to the change in the number of customers between the test year and current period. New customer revenues are therefore preserved to fund new customer investment made by the utility.

The total revenue true up determines the revenue shortfall or surplus by calculating the difference between the target revenues and actual current period revenues by customer group or rate class. The effect of a Total Revenue RDM is that the sum of actual rate class/rate group revenues plus the Total Revenue RDM true up for each rate class/rate group will always equal the revenue target and total actual revenues will not change until the LDC's next rate case. There is no inherent recognition of new customer additions in this approach.

Q. Of these two types of RDM, which is most common for gas LDCs?

A. The application of a RPC RDM best suits utilities that add new customers to their system, and is the prevalent methodology among LDCs that have decoupling. Unlike electric distribution companies, gas LDCs typically do not have 100% market share in their service territories and are motivated to convert customers from alternate fuels, such as oil or propane. Adding new customers to the system involves incremental capital investment, which requires that the revenues from these new customers be necessarily retained by the Company to fund this new investment. Therefore, RPC RDMs are superior to Total Revenue RDMs for gas utilities, as new customer revenues are retained (at the system average RPC) to help cover the cost of the corresponding new investment. If a Total Revenue RDM is employed instead, then the LDCs incentive to add new customers is significantly diminished, as total revenues will remain unchanged while rate base grows.

Q. Does decoupling guarantee utility earnings?

A. No, it does not. The proposed RDM trues up revenues to the amount allowed on a per-customer basis. The utility remains at risk for managing its expenses commensurate with the level set for the test year base rates. This means the utility must manage its capital expenditure programs, its operations (e.g., salaries and wages, benefits, overtime, maintenance programs, uncollectibles, outside services, etc.), and pay taxes (including property taxes that are adjusted annually by most municipalities).

D. LDC Experience with Decoupling

1. Decoupling in the U.S.

Q. Please summarize your research on U.S. gas LDCs that have implemented RDMs.

A. I have identified 67 gas LDCs in 29 states that have implemented a RPC RDM or a Total Revenues RDM. This is summarized as follows:

Table 1: Revenue Decoupling Mechanisms in Effect in the U.S.

State	RPC RDM	Total Revenue RDM	Grand Total
AR	1	2	3
AZ	1		1
CA		4	4
CO	1		1
CT		1	1
GA		1	1
ID		1	1
IL	2	1	3
IN		3	3
LA		1	1
MA	6		6
MD	4	1	5
MI	1		1
MN	1	1	2
MS		1	1
NC	1	1	2
NJ	2		2
NV	1		1
NY	9	2	11
OR	2	1	3
RI	1		1
SC		1	1
TN	1		1
UT	1		1
VA	3		3
VT		1	1
WA	2	1	3
WI	1		1
WY	2		2
Grand Total	**43**	**24**	**67**

Q. Do any LDCs with RDMs also have other ratemaking adjustment mechanisms?

A. Yes, many LDCs with RDMs have also sought recovery of certain expenses and investments (plant / rate base additions) between general rate cases. Cost-related modifications to traditional ratemaking include several approaches to adjusting rates between rate cases to account for changes in (a) overall costs or (b) specific categories of costs. Rate plans that provide for allowed annual increases in a utility's allowed revenues[14] for a set number of years after the rate case is decided is an example of cost based departures that account for changes in overall costs. Step Adjustment increases are common practice in New Hampshire; step adjustments are a form of a rate plan.

Cost tracker mechanisms are another category of modifications to traditional gas LDC ratemaking. Cost trackers recover actual costs incurred on a timely basis. For example, capital cost trackers allow for periodic rate adjustments to recover the incremental revenue requirements associated with replacement and/or safety and reliability projects, while expense cost trackers recover certain specific expenses on a timely basis. New Hampshire has implemented some of these cost tracking measures, including the Cost of Gas Adjustment ("CGA"), indirect gas costs, EE/DSM program costs, environmental remediation costs, and the Cast Iron and Bare Steel ("CIBS") mechanism.

Common cost tracking mechanisms include:

a. Gas costs[15];
b. Pension and Post-Retirement Benefits Other than Pensions ("PBOP") expense;
c. Bad debt expense;
d. Environmental response costs;
e. EE program expense;
f. Property and/or franchise taxes;

[14] For example, the annual revenue increases may be (a) determined for each year of the rate plan in a rate case proceeding, or (b) calculated annually during the rate plan by a formula that accounts for changes in a price index.

[15] Recovery of gas costs through a rate adjustment mechanism is now so common that it is generally considered to be part of "traditional ratemaking."

g. Infrastructure replacement costs (e.g., CIBS);

h. System reinforcement costs, and

i. Integrity management costs.

The following table summarizes the prevalence of pairing an RDM with a cost tracker:

Table 2: LDCs With Decoupling and Cost Tracker

RDM Type	With a Tracker	No Tracker	Total
RPC	**25**	**18**	**43**
Total Revenue	**20**	**4**	**24**
Total	**45**	**22**	**67**

A complete listing of the 67 LDCs that currently have decoupling is included in Attachment GHT/DECPL-1.

Q. Have you identified any other common features in the structure of RDMs that you identified in your research?

A. Yes, I have. In Section III.A of this testimony, I explain that an RDM revenue true up calculation determines the difference between (a) Target RPC and Actual RPC or (b) Target Revenues and Actual Revenues. Both of these approaches to calculating the revenue true up account for differences in revenues that are the result of weather that is colder or warmer than normal in addition to accounting for differences due to conservation and related factors. For example, if weather in the current time period was colder than normal, the RDM would return to customers the revenue surplus associated with the colder weather in the following winter period, and if weather was warmer than normal, the RDM true up calculation would include a charge to recover the revenue deficiency associated with the warmer weather.

Alternatively, an RDM revenue true up calculation could determine the difference between (a) Target RPC and weather normalized RPC or (b) Target Revenues and weather normalized revenues. The true up calculation could be performed by determining the difference between target revenues and weather normalized actual revenues. Using this approach, the revenue true up calculation would not be affected by colder or warmer than normal weather.

Q. What does your research on RDMs indicate about the prevalence of RDMs that are based on actual revenues and RDMs that are based on weather normalized revenues?

A. I determined that 57 of the 67 LDCs have implemented RDMs that are based on actual revenues. Of the remaining 10 LDCs that have implemented RDMs based on normalized revenues, 7 have separate weather normalization adjustment mechanisms ("WNA").

Q. In your opinion, why are most RDMs – approximately 85 percent – based on actual revenues?

A. It is my belief that RDMs that are based on actual revenues, rather than weather normalized revenues, are more common because this RDM approach is easier to administer and oversee as the review process is straight-forward. RDMs that use actual revenues capture all sales-related variances, thus avoiding the need for a WNA (and explanation of its mechanics to customers) or a complicated normalization calculation and subsequent Commission review. Either (a) an RDM that is based on actual revenues or (b) an RDM that is based on weather normalized revenues together with a weather normalization adjustment mechanism have symmetrical, balanced effects that stabilize customers' bills and LDCs' revenues.

Q. What conclusions do you draw from the number of LDCs that have adopted revenue-related and cost-related modifications to traditional ratemaking?

A. Based on the widespread adoption of decoupling mechanisms (67 LDCs in 29 states; see Section III.D.1), of which 45 of these LDCs (two thirds) also have some form of cost tracker, I conclude that there is general understanding that (a) decoupling mechanisms are now viewed as an appropriate ratemaking approach that remove LDC disincentives to effectively promote EE programs and offset the overall effect of conservation on LDC revenues and earnings (b) cost tracking measures are now viewed as an appropriate approach to partially offsetting the effect of LDCs' capital spending plans on earnings between rate cases, and (c) the combination of a decoupling mechanism paired with an appropriate cost tracking measure may be necessary to provide a reasonable opportunity to earn a fair return.

2. Summary and Conclusion to Decoupling Overview

Q. Please summarize your findings about decoupling.

A. Over the past decade or longer, there has been considerable attention given to decoupling, which I believe is the result of a growing acceptance that decoupling is a balanced and administratively manageable ratemaking tool that will: (a) break the link between a utility's revenues and the amount of energy that the utility delivers or sells; and (b) address problems with traditional ratemaking that are caused by long term trends of declining customer energy usage.

I have found that, because LDCs in a number of states have adopted decoupling mechanisms over the last decade, there is now a rich source of data available concerning features of RDMs that have been implemented and issues related to the administration and implementation of RDMs, including, for example, RDM calculations and filing documentation.

IV. ENERGYNORTH'S EXPERIENCE

A. Introduction

Q. In Section III above, you provided a discussion of circumstances that would support the implementation of an RDM. Do those circumstances apply specifically to EnergyNorth?

A. Yes. As I will explain in the remainder of this section, EnergyNorth's circumstances demonstrate that an RDM is appropriate and justified for the Company. Specifically, I will:

- Describe EnergyNorth's current EE programs;
- Summarize the 2015 EERS Settlement Agreement;
- Describe and explain EnergyNorth's recent customer and revenue per customer trends; and
- Demonstrate that EnergyNorth's level of involvement in and support for EE

programs warrant the implementation of an RDM.

B. <u>EnergyNorth's Energy Efficiency programs</u>

Q. Please provide some background on EnergyNorth's EE programs.

A. EnergyNorth has been offering EE programs to its customers since 2003 that provide rebates and technical support for residential and commercial customers who seek to minimize their energy use.[16]. Table 3 below provides a summary of the actual and planned direct energy savings that result from EnergyNorth's EE programs.

[16] Referred to as the "Core programs" in the EERS Settlement Agreement.

Table 3: EnergyNorth Energy Efficiency Program Savings (Annual Dth)

Year	Actual / Estimate	Residential	C&I	Total Energy Savings
2006	Actual	25,529	47,269	72,797
2007		27,151	104,730	131,881
2008		35,360	48,278	83,638
2009		32,414	88,174	120,588
2010		43,524	34,703	78,227
2011		29,281	46,466	75,747
2012		39,702	108,565	148,267
2013		40,509	74,831	115,340
2014		34,401	82,545	116,946
2015		63,685	80,069	143,754
2016	Plan[17]	57,226	65,118	122,344
2017	Proposed Savings Targets	57,791	65,762	123,553
2018		61,594	70,088	131,682
2019		66,158	75,280	141,438
2020		69,958	79,606	149,564

Q. Is the intent of the EE program incentive payment to compensate EnergyNorth for foregone EE revenues?

A. No, the incentive payment is intended to "incent the utilities to aggressively pursue achievement of the performance goals of their energy efficiency programs" and "to motivate the companies to achieve or exceed program goals".[18] It is not intended to offset EnergyNorth's foregone EE revenues.

[17] Settlement Agreement, Attachment B.
[18] *Energy Efficiency Programs for Gas and Electric Utilities*, Order No. 24,203 at 13 (September 5, 2003).

C. <u>The EERS Settlement Agreement</u>

Q. Please describe the EERS Settlement Agreement.

A. The Company, along with the Settling Parties, entered into a Settlement Agreement on April 27, 2016, more than a year after the inception of the Commission's investigation of Staff's proposed Energy Efficiency Resource Standard.[19] The Settlement Agreement represents the Parties' implementation of the approved EERS in New Hampshire,[20] and specifically:

1) Extends the Core programs;
2) Requires implementation of a LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);
3) Contemplates the subsequent implementation of a decoupling mechanism to replace the LRAM;
4) Will implement the EERS commencing January 1, 2018;
5) Retains the Performance Incentive, with modifications;
6) Increases the low income share of the overall energy efficiency budget; and
7) Includes other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (August 2, 2016).

[19] Docket No. IR 15-072, "Electric and Natural Gas Utilities - Energy Efficiency Investigation" dated March 13, 2015.
[20] Settlement Agreement, page 2.

Q. Please describe EnergyNorth's Implementation of the LRAM.

A. EnergyNorth implemented the LRAM effective January 1, 2017.[21] The Local Distribution Adjustment Charge ("LDAC") includes an embedded LRAM of $0.0016/therm and $0.0009 per therm for Residential and C&I customers, respectively. This LRAM will remain in effect (as part of the LDAC) until it is either recalculated for 2018 deliveries or replaced by the proposed decoupling mechanism described in Section V below.

Q. Does the Commission's Order approving the Settlement Agreement specifically require the Utilities, such as EnergyNorth, to implement decoupling?

A. Yes. The Commission approved the Settling Parties' proposed LRAM, and recognized that some parties prefer decoupling to an LRAM. Specifically, the Order states:

> "We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC)) are *required* to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before" (*emphasis added*). [22]

[21] Docket No. DG 16-814, "Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities -2016/2017 Cost of Gas", noticed on September 16, 2016. Approved by Commission Order No. 25,958 (October 26, 2016).
[22] Order No. 25,932 at 60.

Q. Is it the Company's position that proposing a decoupling mechanism in the instant proceeding comports with the Settlement Agreement and the Order?

A. Yes. The phrase "if not before" from the above caption clearly allows the Company to propose a decoupling mechanism prior to the end of the first EERS triennium, if desired.

D. Impact of Customer Consumption Trends on EnergyNorth

1. Introduction

Q. To set the stage for your discussion of the impacts of declining consumption on Energy North, please describe the analysis that you have prepared.

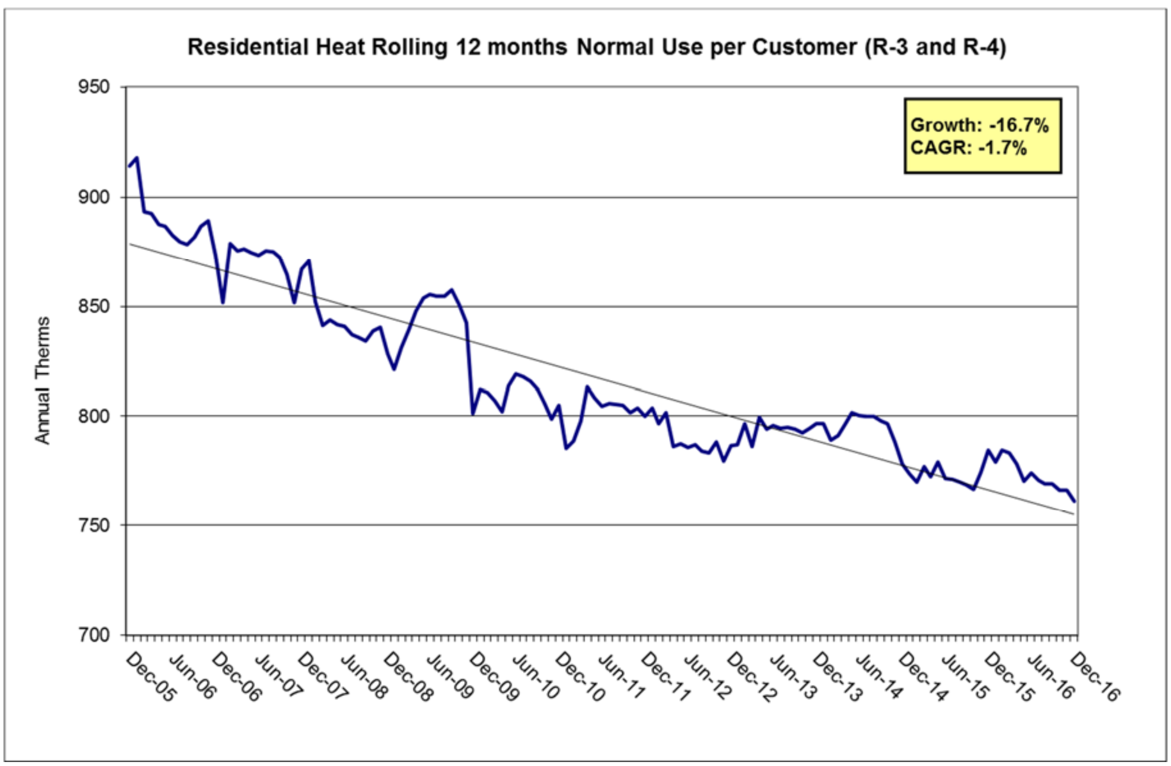
A. In this section, I discuss trends in EnergyNorth's NUPC and number of customers since 2005. I provide summary analyses that I prepared for the following customer groups: (a) Residential Non-Heating; (b) Residential Heating; (c) Low Load Factor C&I; (d) High Load Factor C&I; and (e) Total Company. I prepared separate analyses for the Residential and C&I Customer Groups because customers in these two groups have generally behaved very differently over the period of analysis, 2005 to 2016, particularly the High Load Factor C&I group. I also offer high level explanations for the changes in deliveries, customers and use per customer that EnergyNorth has experienced in the past several years.

2. Analysis of UPC and customer trends

Q. Please summarize the trends in EnergyNorth's weather NUPC that you have identified.

A. To identify trends in EnergyNorth's NUPC, I prepared Residential (Heating and Non-Heating), C&I (Low and High Load Factor) and Total Company NUPC graphs. These graphs are based on a 12-month rolling total NUPC, and are provided in Attachment GHT/DECPL-2. The first graph in Attachment GHT/DECPL-2 shows the NUPC for the Residential Heating Customer Class. A snapshot of this chart is as follows:

Chart 1: Residential Heating NUPC Snapshot



NUPC for the Residential Heating customer class declined 16.7% during the period of analysis, from 912 therms per customer in 2005 to 761 therms per customer in 2016, representing an average annual decline of 1.7%.[23] More recently, from 2013 to 2016 the Residential Heating class has declined at a similar rate of 1.5%.

The Residential Non-Heating NUPC in Attachment GHT/DECPL-2 shows a relatively level usage profile over time, with a 5.3% decline since 2005, or a -0.5% CAGR. Since 2013 NUPC for this class has decreased 12.4%, or 4.3%, primarily as a result of customer rate classification changes. At the conclusion of the last rate case in Docket No. DG 14-180 the Company discovered that 540 existing Rate R-1 customers should have been served under Rate R-3. Following that discovery, the Company initiated a program to convert these customers to Rate R-3.

The two C&I graphs in GHT/DECPL-2 show diverging trends depending on how customers in these classes use natural gas. Low Load Factor ("LLF") customers use gas predominantly for heating, while High Load Factor ("HLF") C&I customers tend to utilize natural gas for process loads, and are potentially subjected to multiple and unique usage drivers compared to LLFr C&I customers (and Residential Heating customers). As these two C&I graphs show, the LLF customer group had declining NUPC from 2005-2010, then rebounded back to 2005 levels by 2014. Their growth rate from 2005 to 2016 showed a slight decline at 0.2%, and a flat CAGR. Conversely, the HLF customer group exhibited rapid NUPC growth over the eleven-year historical period, growing 58.3%, or

[23] As calculated on the Compound Annual Growth Rate ("CAGR") formula.

4.3% annually. Since 2013 the LLF C&I group has remained flat (a 0.1% increase in NUPC) while the HLF C&I class' growth was comparatively lower (0.7% growth since 2013 compared to 4.3% CAGR since 2005).

The last graph in Attachment GHT/DECPL-2 shows that total company NUPC increased slightly by 2.3% percent, or 0.2% annually, which indicates that overall, the increasing HLF C&I NUPC offset much of the decreasing Residential and LLF C&I NUPC over the entire period. Of interest is the recent increase in volatility, including a declining overall NUPC trend since December 2013 of 2.0%. This is likely the result of recent winter period price spikes described further in Section IV.D.3 below.

Q. Please summarize the trends in EnergyNorth's number of customers that you have identified.

A. To identify trends in EnergyNorth's customer counts, I prepared graphs of the number of Residential, C&I and Total Company customers; these graphs are provided in Attachment GHT/DECPL-3. The first graph in Attachment GHT/DECPL-3 shows that the average number of Residential Non-Heating customers decreased by 2,285 (42.9%), or 5.0% annually. This is not surprising, as many low-use customers have converted their heating system to gas over the past decade, taking advantage of the favorable gas-to-oil price spread described in Section IV.D.3 and Table 6 below. The average Residential Heating customer class has increased by 9,914 customers (15.0%), or 1.3% annually. This increase is attributable to heating conversions and new customer attachments to the system (e.g., oil-to-gas conversions and new construction). This growth rate accelerated to 1.8% since 2013.

The next two graphs in Attachment GHT/DECPL-3 show that the number of LLF C&I average customers grew by 1,590 (18.6%), or 1.6% annually, while the HLF C&I class decreased by 86 customers on average, a 5.1% decrease (-0.5% annually).

The last graph in Attachment GHT/DECPL-3 demonstrates that the overall Company customer growth reflects an annual 1.0% growth in average firm customer count. Since the dramatic increase in the oil-to-gas price spread (using a 2013 base), the Residential Heating class has increased to a 1.8% annual growth rate.

3. Explanation for UPC and Customer trends

Q. What are the major contributors to declining NUPC?

A. Categorically, declining NUPC can be attributable to:

1) Utility-sponsored Energy Efficiency (EE)/DSM programs;
2) Customer self-funded conservation measures;
3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to increases in natural gas prices and/other economic and demographic factors; and
5) A warmer normal weather trend.

Q. Please explain each of these factors.

A. Utility-sponsored EE/DSM programs represent the Core programs, plus any additional programs contemplated in the EERS. These measures result in direct energy efficiency spending for EnergyNorth customers. Each program will have an avoided unit of energy and known levels of participation.

Customer self-funded conservation measures are the result of customers acting independently of utility-sponsored programs (e.g., when a customer installs insulation purchased at a home improvement store). Unlike company-funded conservation programs that track actual installed energy efficiency measures, the utility does not track customer-funded installations.

Appliance efficiencies and building code changes affect customer usage whenever an existing (less efficient) appliance is replaced by a new (more efficient) one, and new housing stock replaces old stock. There are known changes to building requirements and appliance efficiency standards that have been enacted over the past few decades. These include increased appliance efficiency requirements for furnaces and hot water heaters. Additionally, New Hampshire has passed a series of more stringent building codes consistent with national standards.

Price elasticity and economic impact on usage can be estimated using econometric modeling, but will have less of a degree of accuracy compared to known and measurable

EE/DSM installations. Although prices are low now[24], in the not so distant past, prices were high and customers responded by installing low cost permanent measures (weather stripping, water heater jackets, set back thermostats, etc.) and high cost permanent measures (insulated doors, added wall and attic insulation, efficient windows, etc.) as well as temporary measures (closing off rooms, turning down thermostats and wearing sweaters). The permanent measures reduce NUPC forever, long after the natural gas prices return to moderate levels. Further, changes in demographics (e.g., number of people per household, number of residents in a service territory or state) can also influence NUPC. Lastly, a significant downward trend in the 30-year normal weather standard also contributes to declining NUPC.

Q. What are the current and forecasted trends for each of these factors?

A. New Hampshire is clearly committed to EE, evidenced by the Settling Parties' commitment to implementing a comprehensive EERS in 2018. Customer-funded conservation measures are likely to continue, as low-cost weatherization options proliferate the home improvement marketplace. Even if the current appliance efficiencies and building codes do not change in the coming years, customer equipment and housing stock will be replaced resulting in net energy savings (e.g., replacing a failed gas furnace with a new gas furnace). Although the gas-to-oil pricing advantage has shrunk since

[24] The U.S. Energy Information Administration ("EIA") Annual Energy Outlook 2017 forecast of residential delivered cost of natural gas shows stable prices through 2025 (2017 forecast = $1.06 per therm compared to the forecasted 2025 delivered price of $1.14 per therm).

2012, the EIA is forecasting a return to a price spread where oil is twice the delivered price of natural gas.[25]

Q. Please elaborate on how customer-funded conservation contributes to declining NUPC.

A. Existing customers have chosen to invest in conservation measures using their own money without utilizing utility-sponsored EE programs. This occurs because of either a lack of understanding of the existence of utility programs or ineligibility based on program requirements. The quantification of energy savings for an individual, representative premise is easily obtainable for many conservation measures. The effectiveness of thermal resistance, for instance, is measured in "R-value" units. Increasing a surface's R-value reduces heat loss. Therefore, when a consumer installs additional insulation in their home, thus increasing the surface's R-value (e.g., attic floor, ceilings, walls, etc.) their natural gas usage (all else being equal) will decline. The following table demonstrates the impact of increasing R-values in a sample 1,000 square foot home in Concord, New Hampshire:

[25] EIA Annual Energy Outlook 2017.

Table 4: Potential Energy Savings from Increased R-Value [26]

Percentage Savings (therms)												
			OLD									
NEW	R-Value	Δ in R	R-10	R-11	R-12	R-13	R-14	R-15	R-16	R-17	R-18	R-19
	R-11	1	2.0%									
	R-12	2	3.7%	1.7%								
	R-13	3	5.1%	3.1%	1.4%							
	R-14	4	6.3%	4.3%	2.6%	1.2%						
	R-15	5	7.4%	5.4%	3.7%	2.3%	1.0%					
	R-16	6	**8.3%**	6.3%	4.6%	3.2%	2.0%	0.9%				
	R-17	7	9.1%	7.1%	5.4%	4.0%	2.8%	1.7%	0.8%			
	R-18	8	9.8%	7.8%	6.1%	4.7%	3.5%	2.5%	1.5%	0.7%		
	R-19	9	10.5%	8.5%	6.8%	5.4%	4.1%	3.1%	2.2%	1.4%	0.6%	
	R-20	10	11.0%	9.0%	7.4%	5.9%	4.7%	3.7%	2.8%	1.9%	1.2%	0.6%

As the above table indicates, an existing homeowner who upgrades their home with insulation, which increases the overall R-value of the dwelling, can decrease their natural gas usage significantly. For example, increasing the R-value from R-10 to R-16 would reduce annual usage from 682 to 626 therms, more than eight percent. Even a modest improvement in R-value can have a significant impact on declining usage.

Q. Please elaborate on how increased appliance efficiencies contribute to declining NUPC.

A. Appliance manufacturers have been improving the energy efficiencies of their gas equipment on both a mandated and voluntary basis. The U.S. Department of Energy ("DOE") regulates minimum efficiency standards for many appliances, including gas furnaces, boilers, and water heaters. In the early 1990s the DOE changed the standards on Annual Fuel Utilization Efficiency ("AFUE") factors. Under the new code, a gas furnace was required to meet at least an 80% AFUE while high efficient gas furnaces

[26] The average usage for a 1,000-square foot house in Concord, NH is estimated at 682 therms per year, using the estimator tool found at www.energydepot.com/residentialenergycalculator. The quantification of saved therms assumes EnergyNorth's normal annual heating degree days of 6,273 and utilizes the Insulation Investment Calculator found at www.chuck-wright.com/calculators/insulpb.html.

must achieve at least an 90% AFUE to meet the new standard. This is an increase from the 78% AFUE standard enacted in 1992.[27] Therefore, whenever an existing gas appliance (e.g., furnace, water heater, stove, dryer, grill, etc.) fails, its replacement will be more efficient and use less gas, resulting in lower NUPC.

Q. Have building codes changed as well?

A. Yes. New Hampshire has adopted the International Energy Conservation Code ("IECC"). Significant changes to New Hampshire's building code changes are as follows:

Table 5: New Hampshire Building Codes

	New Hampshire Building Code Change History
April 2010	2009 IECC adopted, with amendments
July 2007	2006 IECC adopted, with amendments
March 2002	Mandatory statewide building code is signed into law, using the 2000 IECC as reference, effective September 14th, 2002.

Q. How do these building code changes affect natural gas consumption?

A. Similar to the example provided in Table 4, changes in building codes has resulted in mandatory increases in R-value. Therefore, new buildings will be significantly more energy efficient. As old housing stock is replaced, average consumption (all else being equal) decreases.

[27] The National Appliance Energy Conservation Act of 1987, enacted March 17, 1987, and amended by the Energy Policy Act of 1992 and the Energy Policy Act of 2005.

Q. What are the economic and demographic effects on natural gas consumption?

A. I believe, based on preparing LDC demand forecasts, that the most significant economic factors that affected the Company's customer and NUPC trends include: (a) a dramatic spike in gas prices that started in 2005 caused by supply interruptions along the Gulf Coast; (b) equally dramatic decreases in gas prices since 2009, caused by a large increase in supply from shale formations in Pennsylvania and New York; (c) the economic recession that started in December 2007 and ended in June 2009[28]; and (d) the actual and forecasted long term price advantage that gas has over oil, caused by the large increase in gas supplies from shale formations. Some of these factors, such as the increased shale gas supply, have resulted in increased NUPC while other factors such as utility and customer-funded conservation, appliance efficiencies and building codes have contributed to declining NUPC.

To demonstrate the impact of gas prices on the Company's NUPC over the past several years, I have prepared Attachment GHT/DECPL-4, which shows the history of EnergyNorth's Residential Heating (Rate R-3) Cost of Gas ("COG") rates and the New York Mercantile Exchange ("NYMEX") futures settlement values. The significant decrease in COG rates since 2009 has likely had a positive effect on EnergyNorth's

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[28] Recessions are determined by the Business Cycle Dating Committee of the National Bureau of Economic Research. The following is excerpted from a report issued September 20, 2010 by the Business Cycle Dating Committee:

> The Business Cycle Dating Committee of the National Bureau of Economic Research … determined that a trough in business activity occurred in the U.S. economy in June 2009. The trough marks the end of the recession that began in December 2007 and the beginning of an expansion. … In determining that a trough occurred in June 2009, the committee did not conclude that economic conditions since that month have been favorable or that the economy has returned to operating at normal capacity. … The trough marks the end of the declining phase and the start of the rising phase of the business cycle. Economic activity is typically below normal in the early stages of an expansion, and it sometimes remains so well into the expansion.

NUPC during the years immediately following this price change.[29] The polar vortex winter of 2013-2014 had a detrimental impact on national gas prices, coupled with increased concern over capacity constraints in the New England region. As a result, EnergyNorth appropriately responded with COG rate increases during this period. Although these price increases were significant, they were not as severe or long-lasting as the price increases between 2005 and 2009.

I believe that the decrease in Residential NUPC was caused by customer conservation efforts in response to (a) the high gas prices in 2005 – 2006 and again in 2009, and (b) the great recession of 2007-2009, which reduced customers' incomes and wealth.[30] In addition, I believe that more stable and slower declining Residential NUPC since 2010 indicates that the increase in usage that would be caused by the recovery from the recession and the decrease in gas costs has been largely offset by the continuing impact of energy conservation.

Customer NUPC trends during this period have also been impacted by the difference in oil and gas prices. Table 6, below, demonstrates the competitive price advantage that natural gas has had over oil in recent years.

[29] That is, if EnergyNorth COG rates had been constant or increasing during this period rather than decreasing by at least 40 percent, the NUPC growth rates would have been lower than the actual growth rates that are summarized in Attachment GHT/DECPL-2.

[30] In response to the high gas prices, customers installed long term irreversible conservation measures, such as high efficiency gas heating and water heating equipment, energy efficient windows and doors, and increased insulation. Customers also implemented short term reversible conservation efforts, such as reducing temperatures in heated living and working spaces, or closing off parts of homes and buildings. In response to the recession, customers would likely be limited to implementing low-cost, reversible conservation efforts.

Table 6: Residential Delivered Cost of Heating Oil and Natural Gas

Residential Delivered Cost per Therm			
Year	Distillate Fuel Oil	Natural Gas	Oil / gas ratio
2005	$1.42	$1.47	0.970
2006	$1.65	$1.61	1.028
2007	$1.84	$1.63	1.129
2008	$2.33	$1.61	1.445
2009	$1.73	$1.48	1.165
2010	$1.95	$1.40	1.390
2011	$2.36	$1.42	1.670
2012	$2.71	$1.33	2.033
2013	$2.65	$1.34	1.971
2014	$2.58	$1.58	1.638
2015	$1.96	$1.03	1.903
2016	$1.54	$0.99	1.556
2017	$1.85	$1.06	1.745
2018	$2.04	$1.06	1.925
2019	$2.16	$1.07	2.019
2020	$2.21	$1.09	2.028
2021	$2.26	$1.10	2.055
2022	$2.29	$1.10	2.082
2023	$2.33	$1.11	2.099
2024	$2.36	$1.13	2.088
2025	$2.41	$1.14	2.114

2005 – 2014 data from the U.S. EIA Residential Sector Energy Price and Expenditure Estimates, (Table ET3). 2015 - 2025 values from EIA's Annual Energy Outlook 2017.

Given the above natural gas price advantage, existing natural gas customers that use oil for other household needs (e.g., hot water) would be motivated to replace such equipment with gas-fired appliances. Low-use residential customers replacing their oil furnace with a natural gas furnace would increase overall system usage, but may contribute to declining NUPC once they become heating (Rate R-3) customers, as their usage (with a new, efficient furnace) would be lower than the Rate R-3 class average.

Q. How would this oil-to-gas price spread impact C&I customers?

A. I believe that the increases in C&I customers and NUPC have likely been driven by the impact of (a) existing EnergyNorth C&I customers converting from oil to gas equipment to take advantage of the competitive advantage of gas over oil, and (b) new C&I customers also converting to gas equipment, especially on-the-main energy users.

Finally, although overall NUPC has remained relatively flat since 2005, volatility has begun to increase. I believe this increased volatility is a reaction to shorter duration, less severe price spikes over the past three winters. If this trend continues and the price spikes become longer and more severe, NUPC will likely decline.

Q. Please describe how demographics can play a role in NUPC.

A. Demographics can influence NUPC at the individual premise level when more or fewer people occupy the premise. Additionally, premise vacancy rates caused by shifts in population also may affect use per customer[31]. The State of New Hampshire's August 2013 report[32] on the state's economic health recognizes the importance of demographics in the State's economic recovery. In the report, it was recognized that population growth in New Hampshire lags the nation:

> "Population changes may affect New Hampshire job growth and how job needs are met. From 2008 to 2012, the nation's population grew by 3.2 percent, compared to 0.4 percent for New Hampshire. This slower growth was primarily caused by domestic outmigration. A low rate of population growth

[31] Assuming that the premise retains an active gas account for minimal space heating, for example.
[32] "Measuring New Hampshire's Economic Health: A Workforce Perspective", published by the New Hampshire Employment Security, Economic and Labor Market Information Bureau, August 2013.

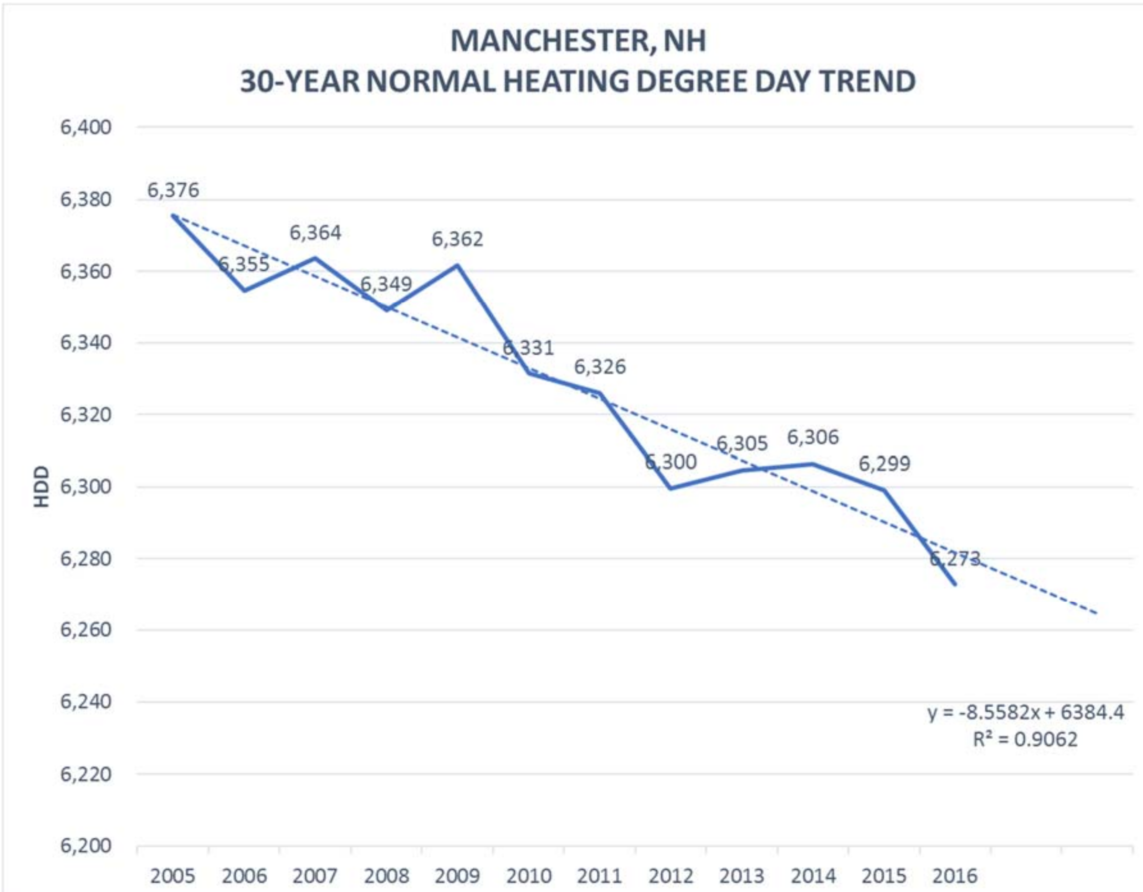
> will affect the rate of job growth in the future, as well as the distribution of jobs by industry and occupation."

Although the above quotation is addressing the issue of employment, it clearly speaks to the trend in New Hampshire's population growth, which can have a direct impact on NUPC, particularly in the Residential classes.

Q. The Company's proposed decoupling mechanism will symmetrically adjust for weather deviations from EnergyNorth's 30-year normal degree day standard. Are there other weather-related reasons to implement decoupling?

A. Yes. Normal temperature, defined in New Hampshire as the latest 30-year average heating degree days, has been declining. The trend over the past decade is for warmer years (most recent) to replace colder years (oldest of the 30-years). This is demonstrated as follows:

Table 7: 30-Year Normal Degree Day History



As the above graph shows, annual normal degree days has declined 103 heating degree-days ("HDD") since 2005. Even under "normal" weather conditions, it is reasonable to assume future year allowed revenues will be deficient if this warming trend continues.

4. Summary and Conclusion

Q. Please summarize why EnergyNorth is proposing, and should be granted, a decoupling mechanism.

A. The EERS Settlement Agreement states that each of the utilities in the state shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM. The Company's preferred solution is decoupling. Further, decoupling is now a mainstream ratemaking tool for gas LDCs across the country. 67 LDCs in 29 different states have a form of decoupling, with the clear majority utilizing actual revenues. EnergyNorth's proposed structure, detailed in Section V below, follows this nationally preferred and accepted design.

Decoupling further solves a long-standing ratemaking issue. There are clear declining NUPC trends in EnergyNorth's largest, most homogeneous customer classes (e.g., Residential Heating) that impact the Company's ability to earn its allowed rate of return. The factors contributing to this declining use reach well beyond utility-funded programs. The data and analysis presented in section IV.D above detail the main contributors to declining NUPC, including: customer-funded conservation; stricter appliance efficiency and building codes; economic and demographic drivers; and a warmer weather trend. None of these factors are within the control of the Company, and the Company should not be penalized between general rate cases for these exogenous events. Decoupling frees EnergyNorth from the negative effects of these causes of declining NUPC, and enables unfettered support and promotion of the State's energy efficiency goals.

V. ENERGYNORTH'S DECOUPLING PROPOSAL

A. Details of EnergyNorth's Proposed Decoupling Mechanism

1. Introduction

Q. Please provide a general description of the decoupling mechanism that EnergyNorth is proposing.

A. The Company is proposing a RPC decoupling mechanism that will be applied to all customers in all firm tariffed rate classes. The proposed RDM provides for separate winter and summer rate adjustments that correspond to the seasonality of the Company's distribution rates and Cost of Gas clause.

Q. Please list the RDM components that define EnergyNorth's proposed RDM.

A. EnergyNorth's proposed RDM is defined by the following RDM design components:

1) Basis for the true up calculation;
2) Rate classes to be included in the RDM;
3) Rate classes to be included in separate true-up customer groups;
4) Approach for returning RDM revenue surplus or recovering revenue shortfall from customers;
5) Frequency and timing of RDM rate adjustment filing;
6) Adjustments to Actual and Target revenues;
7) Treatment of new customers; and
8) Customer impact protections.

I will describe, explain and support these components of the Company's proposed RDM in the following sections of my testimony.

2. Basis for the true up calculation

Q. Please explain the approach that the Company is proposing for the true up calculation.

A. As described earlier in my testimony, the Company's proposed decoupling mechanism is a RPC RDM. A RPC RDM is critical to providing the Company with some opportunity to earn a reasonable return between rate cases, and retain revenues related to the growth in customers. Our RDM research indicates that RPC decoupling mechanisms are most common for gas LDCs because LDCs are experiencing significant customer growth that is related to the strong economic incentives for conversion from oil to gas. A RPC decoupling mechanism provides growth in revenues to partially offset the costs to connect the new customers.

3. Rate classes to be included in the RDM

Q. Which rate classes will be included in the Company's proposed RDM?

A. EnergyNorth proposes to include all firm tariffed customer classes in the RDM true up calculations, and to apply RDM rate adjustments to all firm rate classes.

It is appropriate to apply the RDM to all customers because (a) all EnergyNorth firm customers are eligible for the Company's EE programs and (b) Residential and C&I customers are likely to implement conservation efforts that are not directly associated with EnergyNorth's EE programs.

The RDM will not be applied to special contract customers because special contract customers are not eligible for EE programs, and special contract customers are not charged other rate adjustments, such as the LDAC.

4. True up Customer Groups

Q. How will the Company's customers be grouped for purposes of administering the proposed RDM?

A. The Company's firm rate classes will be combined into RDM Customer Groups as shown in Table 8 below:

Table 8: RDM Customer Groups

RDM Customer Group	Firm Rate Classes
Residential Non-Heating	R-1
Residential Heating	R-3, R-4
Commercial and Industrial	G-41, G-42, G-43, G-51, G-52, G-53, G-54

Q. Please explain why you are proposing to combine rate classes into the three rate groups that you have listed in Table 8, rather than keeping each C&I rate class separate?

A. I am not proposing to keep each rate class separate because C&I customers are assigned to the C&I rate classes based on their annual usage and percent of their annual usage that occurs in the Winter period. The potential shifting of C&I customers between rate classes may cause unintended results in the RDM calculations; these unintended results are avoided if all C&I customers are included in the same RDM customer group. In addition, I have prepared Attachment GHT/DECPL-5 to provide a summary of the variability in normal revenue per customer for each of the C&I rate classes[33]. Attachment GHT/DECPL-5 demonstrates that there is significant year-to-year variability in normal revenue per customer for several C&I rate classes, especially the large use classes G-42, G-43 and G-53. If the Company's RDM provided for separate revenue true ups and separate RDM rate adjustments for each C&I rate class, the calculation of the seasonal revenue shortfall/surplus would be significantly affected by whether the target RPC for that rate class had been determined in an "up" year or a "down" year. Separate RDM rate adjustments for each C&I rate class would likely result in noticeable rate volatility for some C&I rate classes.

This potential volatility is avoided with a single RDM true up calculation for all C&I rate classes combined. Attachment GHT/DECPL-5 also demonstrates that the normal revenue per customer for all C&I rate classes combined is relatively stable. Thus, the seasonal calculated revenue shortfall or surplus for the combined C&I RDM customer group will not be affected by the year (i.e. the rate case test year) that is used to determine the target RPC.

5. Frequency and timing of RDM rate adjustment filing

Q. Please explain how often and when the RDM rate adjustments will be made.

A. The Company will calculate separate Winter and Summer season RDM rate adjustments based on the prior winter or summer season RDM revenue shortfalls or surpluses, for

[33] This analysis is based on the same actual and weather normalized billing determinant data that was used to prepare Attachment GHT/DECPL-7; monthly revenues are based on 2016 rates, and R-4 revenues are calculated at R-3 rates. Additional discussion of the decoupling data base and analysis is provided in Section V.10.

each RDM customer group. Separate seasonal RDMs would reduce the shifting of charges or credits (associated with RDM revenue shortfalls or surpluses) between temperature sensitive and non-temperature sensitive customers.

6. Adjustments to Target and Actual revenues

Q. Please explain how the RDM Target Revenue per Customer will be determined.

A. The initial Winter and Summer RDM Target Revenue per Customer will be set in this proceeding; the target RPCs for each RDM customer group and for each season will be calculated in the Company's compliance filing by summing the allowed revenues by season for each RDM customer group, divided by the seasonal average number of RDM customer group customers.

For each seasonal RDM filing, the RDM target RPCs will be adjusted to account for the rates that were in effect during the recently-completed RDM season, because the Company's base distribution rates are adjusted annually, effective every July 1 to reflect the CIBS rate adjustment. The derivation of the Target Revenue per Customer by RDM Rate Group, based on the Company's proposed rates, is included as Attachment GHT/DECPL-9.

Q. Please explain how actual revenues per customer will be calculated.

A. Winter and Summer Actual Revenues per Customer, by RDM Rate Group, will be calculated directly from the actual booked base distribution revenues and actual booked number of average customers. The Company will calculate the RDM Actual Revenues per Customer and the RDM revenue shortfall/surplus monthly on a calendar month basis.

At the end of each season, the Company will sum all of the monthly data and will calculate RPC on a seasonal basis.

7. Treatment of new customers

Q. How will new customers be treated in the Company's proposed RDM?

A. The Company will include new, non-expansion rate customers in the RDM calculations. These customers will be charged the rate adjustments associated with the RDM and the calculations of actual revenues per customer will include the new customers. The Company proposes that expansion rate new customers be excluded from the RDM calculation and not be charged or credited the RDM rate. The reason for this proposed exclusion is that the expansion rates include a higher delivery rate than existing or new (non-expansion) customer rates. For example, expansion rate R-6 (Residential Heating - Expansion) delivery rates are 30% higher than existing R-3 Residential Heating rates. If R-3 and R-6 customers were included in the same RDM customer group, then the revenues associated with the 30% R-6 delivery premium, all else being equal, would be returned to all customers through the RDM. This defeats the purpose of the expansion rates, whereby the delivery premium revenue supports the incremental costs of the expansion investment.

An alternative treatment that creates a separate RDM customer group for expansion customers is not appropriate. Currently there are no expansion rate customers. Therefore, the near-term population of expansion rate customers will be small and would likely result in an unstable RDM calculation. For these reasons the Company proposes to exclude expansion rate customers from the RDM until they are migrated into the existing rate schedules once their expansion term expires.

8. Customer impact protections

Q. Is EnergyNorth proposing a customer impact cap on the annual RDM adjustments?

A. Yes. The Company's proposed RDM includes a plus or minus 5 percent cap on rate changes; that is, the RDM increase or decrease to rates will be limited to 5 percent of distribution revenues (revenues that exclude charges for COG and LDAC revenues, and all other related charges). Any excess over the 5 percent upper or lower limit will be deferred for recovery in the next period with carrying charges at the prime lending rate. The proposed 5 percent customer impact cap, based on distribution rates, is approximately equivalent to a 2.5 percent increase in total bills.[34]

Lastly, the proposed RDM includes a provision that the Company will file for a mid-period adjustment if the projected RDM end of season under or over collection exceeds 10 percent of total projected seasonal distribution revenues.

9. Summary

Q. To summarize, please describe how the Company's proposed RDM will be calculated and applied.

A. As a general summary of my testimony in this section, summer and winter RDM adjustments will be determined prior to the start of each season by (1) calculating Target

[34] The percent increase based on all charges, including COG and LDAC rates in addition to distribution rates, will depend on the level of the COG and LDAC rates at any time.

Revenue[35] per customer for that season for each RDM Rate Group; (2) calculating actual revenue per customer for that season (i.e. the most recently completed season) for each RDM Rate Group; (3) calculating the difference between Target and actual revenue per customer; (4) calculating RDM Rate Group revenue shortfalls or surpluses by multiplying the revenue per customer differences times actual average monthly customers for each rate group; (5) calculating the Company total revenue shortfall or surplus by summing the RDM Rate Group revenue shortfalls or surpluses; and lastly (6) calculating the RDM adjustment by dividing the Company total revenue shortfall or surplus by projected therm deliveries for the upcoming season.

This adjustment will also include a reconciliation of the same season prior period authorized Company total revenue shortfall or surplus to actual revenues recovered or returned in the same season prior period.

10. Additional RDM details

Q. Have you prepared a schedule to illustrate how the RDM calculations would be made?

A. Yes, I have prepared Attachments GHT/DECPL-6 and GHT/DECPL-7 for that purpose. To prepare this hypothetical illustration I used actual Company data for the period from January 2010 - 2016 to show:

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35 The summer and winter Target Revenue per customer for each rate group will be determined from the revenue requirement approved in this proceeding.

The calculation of the Target RPC for the three customer groups (Residential Heating, Residential Non-Heating, and C&I). I developed the Target RPC for a 2010 Test Year, which is shown in Attachment GHT/DECPL-6.

The calculation of actual RPCs, RDM revenue shortfalls or surpluses per customer, and total revenue shortfalls or surpluses for Summer 2011 through Summer 2016, which is shown in Attachment GHT/DECPL-7.

The hypothetical calculations for all years (2010-2016) utilize 2016 rates.

Q. Please summarize the results of the analysis that is provided in Attachment GHT/DECPL-9.

A. I have prepared Table 9,[36] below, to summarize the revenue shortfalls, by season, from Summer 2011 through Summer 2016:

[36] Please see Attachment GHT/DECPL-7 for supporting calculations. Also, Table 10 below provides further explanatory information regarding these hypothetical results.

Table 9: RDM Class Accrual Analysis

	Accrued Revenue Shortfall (Surplus) $			
	R-1	R-3, R-4	C&I	Total
Summer 2011	$763	$207,719	$15,778	$224,260
Winter 2011 - 2012	$3,978	$2,233,390	$1,732,447	$3,969,815
Summer 2012	$1,846	$373,048	$71,814	$446,707
Winter 2012 - 2013	-$15,033	$346,231	-$175,192	$156,005
Summer 2013	-$592	$288,368	-$124,816	$162,960
Winter 2013 - 2014	-$45,365	-$1,469,303	-$1,964,463	-$3,479,131
Summer 2014	-$687	$175,820	-$500,720	-$325,587
Winter 2014 - 2015	-$3,697	-$910,895	-$1,847,245	-$2,761,837
Summer 2015	$3,499	$356,979	-$421,197	-$60,720
Winter 2015 - 2016	$5,915	$2,509,631	$1,171,639	$3,687,184
Summer 2016	$3,656	$381,248	-$299,262	$85,642

[1] Utilizing a 2010 base year and billing determinants and 2016 billing rates.

Q. How will the seasonal revenue shortfalls or surpluses be billed to customers?

A. As described above, a singular rate per therm will be calculated each season based on the sum of the accrued class RDMs, and billed the subsequent matching season. For example, the Summer 2011 total accrued shortfall of $224,260 will be collected over the 2012 summer period. The rate per therm will be calculated on a total system basis and applied to all firm rate classes.

These accrued seasonal totals must first pass the 5% test prior to calculating the billing rate per therm. If the RDM accrual is a shortfall and exceeds 5% of total distribution revenues for that season, then the dollars in excess of 5% will be deferred for recovery until the next applicable season. For example, the Winter 2011/2012 total RDM value exceeded 5%; therefore, the excess dollars would have been deferred until the following

2012/2013 winter period. The 5% test applies to the sum of the calculated RDM and deferred RDM for the applicable period. This may result in deferred dollars not being collected for multiple seasons, if the RDM continues to yield a surcharge in excess of the 5% limit. However, the Company's proposal includes a provision whereby if the calculated RDM exceeds 10%, the Company may petition the Commission for a more immediate recovery of the RDM dollars in excess of 10%.

Based on the sample data, the billing of the calculated seasonal RDMs is as follows:

Table 10: Seasonal RDM Accruals, Deferrals, and Billing Rates

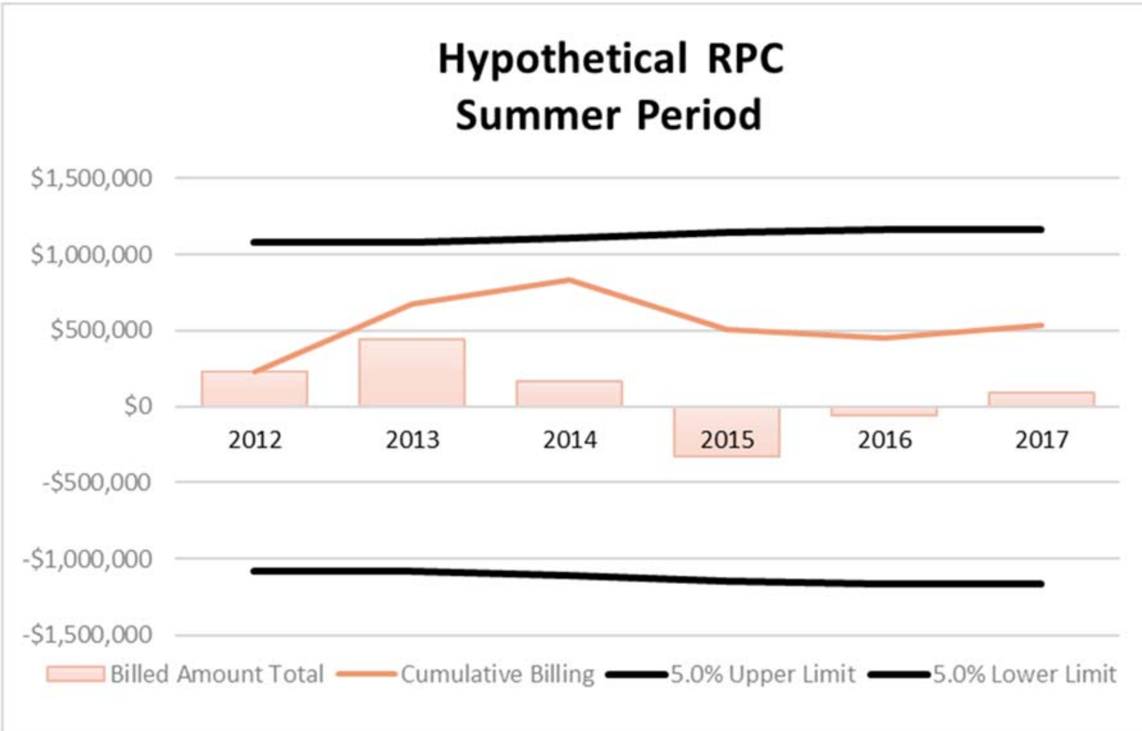
Hypothetical RDM

	Accrued Revenue Shortfall (Surplus) $				**+/- 5.0% Limit Test**		**Billable Amounts**		
Season	R-1	R-3, R-4	C&I	Seasonal Accrued Total	klokoshjlzih	Deferral	Adjusted Total	Adjusted % of distribution revenues	Rate Per Therm
Summer 2011	$763	$207,719	$15,778	$224,260	1.0%	$0	Billing Lag		
Winter 2011 - 2012	$3,978	$2,233,390	$1,732,447	$3,969,815	9.8%	$1,937,300			
Summer 2012	$1,846	$373,048	$71,814	$446,707	2.1%	$0	$224,260	1.0%	$0.0061
Winter 2012 - 2013	-$15,033	$346,231	-$175,192	$156,005	0.3%	$0	$2,032,515	5.0%	$0.0178
Summer 2013	-$592	$288,368	-$124,816	$162,960	0.7%	$0	$446,707	2.1%	$0.0113
Winter 2013 - 2014	-$45,365	-$1,469,303	-$1,964,463	-$3,479,131	-7.1%	-$1,022,620	$2,093,305	4.7%	$0.0180
Summer 2014	-$687	$175,820	-$500,720	-$325,587	-1.4%	$0	$162,960	0.7%	$0.0042
Winter 2014 - 2015	-$3,697	-$910,895	-$1,847,245	-$2,761,837	-5.5%	-$1,261,730	-$2,456,511	-5.0%	($0.0207)
Summer 2015	$3,499	$356,979	-$421,197	-$60,720	-0.3%	$0	-$325,587	-1.4%	($0.0075)
Winter 2015 - 2016	$5,915	$2,509,631	$1,171,639	$3,687,184	8.4%	$240,762	-$2,522,728	-5.0%	($0.0211)
Summer 2016	$3,656	$381,248	-$299,262	$85,642	0.4%	$0	-$60,720	-0.3%	($0.0014)
Winter 2016 - 2017							$2,184,693	5.0%	$0.0180
Summer 2017							$85,642	0.4%	$0.0021
					Outstanding Deferrals	Winter	$240,762		
						Summer	$0		

Based on a 2010 base year and billing determinants, and 2016 billing rates.

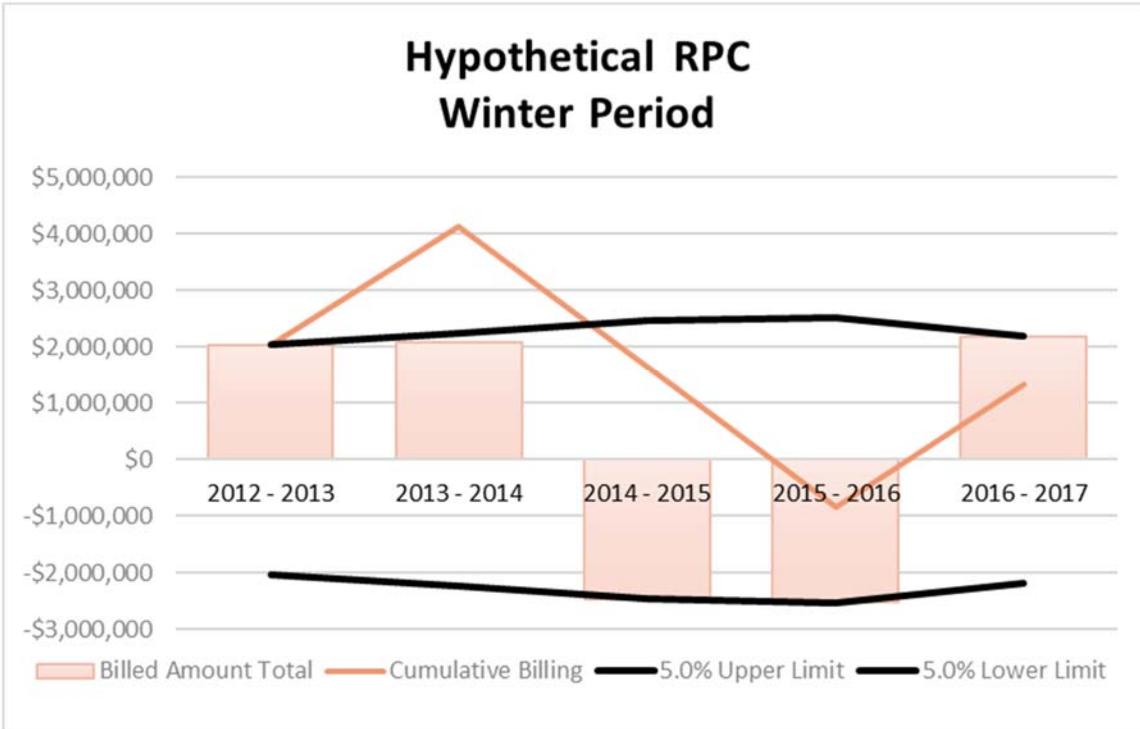
1 The results of the above calculations are shown graphically below:

2 **Chart 2a: Cumulative Effect of RDM - Summer**



3

Chart 2b: Cumulative Effect of RDM - Winter



Tables 9 and 10 demonstrate that if an RDM had been in effect during this period, the RDM rate accrual would have been a debit (charge) in 5 seasons and a credit in the other 6 seasons. The largest shortfall is $3,969,815, or 9.8% of distribution revenues and the largest surplus is -$3,479,131, or 7.1% of distribution revenues. On a cumulative basis, the five-year cumulative RDM shortfall would have been $2,105,298; or 0.6% of total distribution revenues.

On a billed basis, the RDM rate adjustments would have been generally small. Seven of the seasons would have resulted in a charge to customer bills, and four seasons would have been credits. The 5 percent customer impact cap would have been applied in two of the five winter seasons, to be recovered in following winter periods. The 5 percent cap would not have been exceeded in any of the six summer periods. Lastly, there is a hypothetical shortfall to be collected in the Winter 2017 – 2018.

Q. Please describe the timing of RDM calculations, filings, and rate adjustments.

A. I have prepared Attachment GHT/DECPL-8 to illustrate the timing of RDM calculations, filings, and rate adjustments. Referring to Attachment GHT/DECPL-8, the Winter or Summer RDM Adjustment Factor will be based on the calculations related to the most recently completed corresponding Winter or Summer RDM prior period. The Company proposes to make its Winter RDM filing together with its annual LDAC filing, on or before September 1 of each year and each Summer RDM filing will be made on or before March 1 of each year. Each Winter and Summer RDM filing will also include a final reconciliation of actual and allowed RDM revenues for the prior same period.

Q. Has the Company prepared an RDM tariff provision?

A. Yes. The Company's proposed Local Distribution Adjustment Clause ("LDAC"), which includes provisions for the RDM in Section 18(C.1) of the LDAC, is included in the proposed tariff in this proceeding. Section 18(C.1) describes the manner in which the Company proposes to annually true up Actual Revenues versus Target Revenues, and to recover the RDM Adjustment Factors through rates. Section 18(C.1) also describes the documentation that the Company will provide with annual RDM filings. This new RDM language replaces the current "Lost Revenue Adjustment Mechanism Allowable for LDAC" provisions, as the proposed RDM replaces the LRAM in its entirety.

Q. Does this complete your testimony?

A. Yes, it does.