Liberty Utilities

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 14-180

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

DIRECT TESTIMONY

OF

JAMES D. SIMPSON

August 1, 2014

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JDS/DECPL-2	EnergyNorth Annual Customers, 2002 - 2013
JDS/DECPL-3	EnergyNorth Annual Average Cost of Gas, 2006 - 2012
JDS/DECPL-4	EnergyNorth Annual Average Cost of Gas Jan 2007 – July 2013
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I. INTRODUCTION

Q. Please state your name, address and position.

A. My name is James D. Simpson. I am a Senior 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 Rates-11.

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

A. Yes, I testified on behalf of Northern Utilities ("Northern") in Northern's 2013 rate case in support of the proposed alternative rate plan; I also testified on behalf of Northern in several Cost of Gas proceedings.[1] In addition, while I was employed by Bay State Gas Company, I testified before the Commission on behalf of Northern Utilities in many proceedings on a variety of issues related to rates, growth-related projects and other economic and regulatory matters.

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 James D. Simpson); (2) preparing the

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1 (a) 2009 Summer Cost of Gas ("COG") proceeding, Docket No. DG 09-052; (b) 2009 / 2010 Winter COG proceeding, Docket No. DG 09-167; (c) 2010 Summer Cost of Gas proceeding, Docket No. DG 10-050, (d) 2010 / 2011 Winter Cost of Gas proceeding, Docket No. DG 10-250; and (e) 2011 Summer Cost of Gas ("COG") proceeding, Docket No. DG 11-045.

Marginal Cost Study (Marginal Cost Testimony of James D. Simpson); and 3) together with Company Witness Stephen R. Hall, developing the rate design (Joint Rate Design Testimony of Stephen R. Hall and James D. Simpson) for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

Concentric has also been engaged by the Company to develop and support a Functional Cost of Service Study ("FCOS"); the FCOS is provided in the testimony of David A. Heintz.

II. SCOPE OF DECOUPLING TESTIMONY

Q. Please summarize your testimony concerning the Company's proposed revenue decoupling mechanism.

A. In this testimony, I will:

(1) provide general background on revenue decoupling mechanisms ("RDM");

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

(3) describe the impact in recent years that EnergyNorth's Energy Efficiency ("EE") programs combined with customer-driven conservation has had on the Company's throughput volumes and therefore on the Company's ability to earn a reasonable rate of return between rate cases;

(4) describe and explain the Company's proposed Revenue Decoupling

Mechanism ("RDM"), which will (a) allow EnergyNorth to remain a forceful advocate for energy conservation efforts; and (b) provide EnergyNorth with a better opportunity to earn a reasonable rate of return in spite of the continuing effect of EnergyNorth's EE programs and customer conservation on the Company's throughput volumes, distribution base revenues and earnings.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

- In recent years there has been heightened focus on energy conservation efforts and enabling policies to encourage conservation.[2] This interest in energy conservation has been attributed to environmental considerations and to a dramatic spike in energy prices that occurred in 2005 – 2006. Although gas prices have dropped significantly since 2009, the attention to gas conservation has continued.[3]
- Until three years ago, EnergyNorth had experienced a dramatic decline in usage, as measured by Normalized Use per Customer (NUPC), which had

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2 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, (November 2013), prepared for the New Hampshire Office of Energy and Planning by the Vermont Energy Investment Corporation; and (c) New Hampshire State Energy Strategy (Draft May 2014), prepared by Navigant Consulting, Inc. for the New Hampshire State Energy Council

3 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.

negatively impacted the Company's ability to earn a fair return on equity. In more recent years, EnergyNorth's overall customer usage has leveled off, because continuing declines in usage by some classes has been offset by increases in usage by other classes.

- EnergyNorth is not alone - most US gas distribution companies have been experiencing similar patterns of declining use, with similar earnings implications.
- EnergyNorth proposes to implement rate design measures[4] that will "decouple" the traditional connections between the volumes that EnergyNorth delivers to its customers and its revenues and earnings.
- The decoupling rate design measures that the Company is proposing:
  - Are informed by similar measures that have been implemented by a large number of gas distribution companies in recent years;
  - Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;
  - Will fix a flaw with traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

[4] 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.

III. OVERVIEW OF DECOUPLING

A. Introduction

Q. Please describe a decoupling mechanism.

A. In general terms, an RDM breaks the connection between the quantities that a utility delivers to its customers and that utility's revenues. Thus, between rate cases, because the RDM has made that utility indifferent to the total quantity of gas delivered, there is no financial incentive to increase gas deliveries to existing customers and there is no financial disincentive to providing effective energy efficiency programs. 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 was set in the most recent rate case, and 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, and a rate adjustment charge will be included in customers' bills when actual revenue per customer is less than the target revenue per customer.

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

A. 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 related to the revenue "true up" calculation. 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 an 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.

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.

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

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

A. The American Council for an Energy Efficient Economy 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.

C. Support for Decoupling: Ratemaking

Q. Please explain "traditional ratemaking".

A. Traditional cost of service/rate of return regulation, as practiced by state regulatory agencies including the Commission, is based on an analysis of a utility's cost of doing business in a recent historical period ("Test Year") to determine the level of revenues – the Revenue Requirement - that would have allowed the utility a reasonable opportunity to earn a fair rate of return in that historical period. The revenue requirement consists of (1) expenses; (2) return of investment in plant (depreciation); (3) return on investment in plant; and (4) taxes. Typically, state regulators, including the Commission, allow adjustments to test year costs to ensure that the historical costs are representative of the costs that are likely to be experienced in the future period when the new approved rates will take effect. The return on investment component of the revenue requirement accounts for the cost of debt that the utility has issued and the cost of equity, which is determined by analysis to be the return that will allow the utility to maintain credit and attract investors.

Q. Under what conditions does traditional ratemaking allow a utility a reasonable opportunity to earn a fair return?

A. Traditional ratemaking, which is based on an examination of historical utility costs and billing determinants, is designed to allow regulated utilities to earn a fair rate of return if the conditions that affect utility revenues and costs are generally similar and consistent between the historical test year period and the future periods when the rates that are determined from the test year data will be charged. Traditional ratemaking may not produce reasonable results when the conditions that affect utility costs and revenues in the years that the rates will be charged are very different from the conditions that were experienced during the test year.

Q. Please explain why the current rate design approach no longer "works"?

A. Decoupling measures are an increasingly common category of revenue-related modifications to traditional ratemaking because the conditions that will impact utility revenues in the future when a specific set of base rates will be charged are very likely to be different from the conditions[5] that were experienced during the test

5 Conditions that have had a long run impact on revenue per customer trends for at least the past decade include customer driven conservation efforts, utility-sponsored energy efficiency programs, and improvements in equipment efficiency standards. Climate change may also be a condition that has had a long run impact, if normal (expected) degree days is declining over time. Year-to-year variability in weather, as measured by degree days, for example, is not a condition that would cause traditional ratemaking to "not work" if warmer than normal weather and colder than normal weather are balanced. In statistical terms, "warmer than normal weather balanced with colder than normal weather" means

year that was used to determine that set of base rates, as a result of conservation and other demand response efforts. The effect of those conditions that impact utility revenues is to make it less likely that an LDC has a reasonable opportunity to earn a fair return.

Q. Please discuss revenue-related and cost-related modifications to traditional ratemaking that may be necessary to allow a utility a reasonable opportunity to earn a fair return in the conditions that LDCs must contend with at the present.

A. I have already discussed "Revenue-related modifications to traditional rate making," which is another term for decoupling.

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[6] 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. Capital cost trackers that allow for periodic rate adjustments that recover the

that the distribution of degree days is normally distributed with a mean (average) that is constant. The revenue-related modifications to traditional ratemaking that many LDCs have implemented address year-to-year variability in weather; the primary purpose of these modifications is to stabilize customer bills and LDC revenues.

6 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,

incremental revenue requirements associated with replacement and/or safety and reliability projects is an example of cost based departures that account for changes in specific categories of costs.[7]

D. LDC Experience with Modifications to Traditional Ratemaking

1. Decoupling: Revenue-related Modifications to Traditional Ratemaking

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

A. I have identified 51 gas LDCs in 22 states that have implemented RDMs that true up actual revenues to target revenues on either a revenue per customer basis ("RPC RDM") or a total revenue basis ("Total Revenue RDM"). In addition, some LDCs have implemented RDMs that also adjust target revenues annually to account for the revenue requirement effects of inflation and additions to plant and rate base; these annual target revenue adjustments, called "stairstep" revenue increases are generally (a) determined by a formula approved by the LDC's regulators; or (b) set at an approved amount, based on regulatory review in the rate proceeding of the LDC's revenue requirements forecast. Table 1 summarizes the implemented RDM types.

7 More broadly, cost-related modifications to traditional gas LDC ratemaking include cost tracking mechanisms that reconcile actual costs incurred for the specific activity in a period – e.g. annually, semi-annually, or quarterly – with cost tracker revenues billed in the same period. Common cost tracking mechanisms include (a) Gas costs, (b) Pension and PBOP expense, (c) bad debt, (d) Infrastructure replacement costs (such as EnergyNorth's CIBS mechanism), (e) Environmental response costs, (e) EE program expense, (f) system reinforcement costs, and (g) Integrity management costs. Recovery of gas costs through a rate adjustment mechanism is now so common that it is generally considered to be part of "traditional ratemaking."

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

	Includes Stairstep	No Stairstep	Total
Revenue per Customer	5	32	37
Total Revenue	6	8	14
Total	11	40	51

Q. Please explain why 11 LDCs have implemented RDMs combined with stairstep revenue increases.

A. Depending on an LDC's specific circumstances[8], an RDM alone may not be adequate to provide an LDC with a reasonable opportunity to earn a fair return – to achieve that reasonable opportunity, LDCs must have some ratemaking treatment such as stairstep increases or cost tracking mechanisms that account for a meaningful portion of an LDC's year-to-year cost increases. In the absence of an appropriate stairstep provision or cost tracking mechanism, an LDC is likely to continue to have a limited opportunity to earn a fair return between rate cases and is also likely to file rate cases more frequently than LDCs with RDMs and some form of provision to change rates annually. I have provided further details on LDC capital cost tracking mechanisms in Section III.D.2.

[8] For an LDC that has implemented an RDM, the specific circumstances that will affect that LDC's opportunity to earn a reasonable return may include the LDC's capital spending, rate base, the effects of price inflation on expenses, and similar factors that impact revenue requirements.

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 explained that an RDM trues up revenues by calculating 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 is colder than normal, the RDM Adjustment will also include a rate decrease to reflect the effect of the colder weather; if weather was warmer than normal, the RDM adjustment would also include a rate increase to reflect the effect of the warmer weather.

Alternatively, 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 40 of the 51 LDCs have implemented RDMs that are based on actual revenues; the other 11 LDCs have implemented RDMs that are based on weather normalized actual revenues. However, all of those 11 LDCs have implemented separate weather normalization adjustment mechanisms, so that all 51 of these LDCs have one of the two forms of weather normalization adjustment. In Table 2 below, I have expanded Table 1 to reflect this weather normalization feature of RDMs.

Table 2: Structure of RDMs in Effect in the U.S.

	RDM Structure				
Effect of Weather	RPC	Total Revenue	Total Revenue w/ stairstep	RPC w/ Stairstep	Total
Full Decoupling	24	5	6	5	40
Separate WNA from RDM	8	3	0	0	11
Total	32	8	6	5	51

Q. In your opinion, why are most RDMs – almost 80 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. In addition, 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.[9]

2. Cost Trackers: Cost-related Modifications to Traditional Ratemaking

Q. Please summarize your research on LDCs that have implemented capital spending cost tracking mechanisms.

A. Because current conditions do not provide an LDC with a reasonable opportunity to earn a fair return for an extended period of time[10], many LDCs have recently implemented non-traditional ratemaking approaches to recover capital spending costs between rate cases. In general, the research that I conducted to identify common approaches that LDCs have adopted to recover capital spending costs between rate cases[11] indicates that there are three general categories of non-traditional capital recovery ratemaking approaches, which are differentiated by the characteristics of the capital projects that are covered: (a) special purpose projects, such as safety-related replacement projects; (b) large projects, such as major reinforcement or expansion projects; and (c) all capital spending. Table 3, below,

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9 As previously stated, the effect is not symmetrical and balanced if normal weather is becoming colder or warmer over time. In that case, an RDM that is based on actual revenues or a weather normalization adjustment mechanism are appropriate to address a failure in traditional ratemaking that result when the conditions that affect utility revenues and costs are not similar and consistent between the historical test year period and the future periods when the rates that are determined from the test year data will be charged.

10 In this context, an "extended period of time" is perhaps three to five years.

11 This research does not address approaches to recover increases in expenses between rate cases. In recent years, in response to the significant levels of gas LDC capital spending for infrastructure replacement, system reinforcement and integrity management considerations, most focus has been on ratemaking approaches to recover these capital-related costs. Rate plans, including stairstep increases, address increases in expenses as well as increases in capital-related costs.

which summarizes my research is taken from my testimony in the Northern 2013 rate case, Docket No. DG 13-086.

Table 3: Gas Distribution Utility Capital Cost Recovery Approaches (2013)

Category	Types of Eligible Assets	Examples of Eligible Assets	Implementation rate Number of: States[12]	Implementation rate Number of: Companies[13]
Special Purpose Projects (e.g. TIRA)	• Typically non-revenue generating • Targeted • Out of the ordinary	• Cast iron/ bare steel replacement programs • Pipeline system integrity • Relocating inside gas meters • City and state construction projects	20	41
Large Projects	• Very large • Defined, specific projects • May include revenue generating projects	• Specific system expansion / system growth areas • Reinforcement projects • Automated meter reading devices	3	6
Comprehensive	• All capital spending	N/A	10	22
Total unique states, companies			28	64

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 (51 LDCs in 22 states; see Section III.D.1) and capital recovery approaches (64 LDCs in 28 states), I conclude that there is general understanding that (a) decoupling mechanisms are

12 The sum of the states that have implemented capital recovery rate adjustment mechanisms, by category, is greater than the 28 total states that have implemented non-traditional capital recovery ratemaking approaches because some states are represented in more than one category. Also, although Iowa and Nebraska gas distribution companies are authorized to implement capital recovery rate adjustment mechanisms by legislation or generic regulatory proceeding, no companies in these states have implemented a capital recovery rate adjustment mechanism at this time.

13 The sum of the companies that have implemented capital recovery rate adjustment mechanisms, by category, is greater than the 64 total companies that have implemented capital recovery rate adjustment mechanisms because some companies are represented in more than one category.

now viewed as an appropriate ratemaking approach that removes LDC disincentives to effectively promoting EE programs and offsets 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 reasonable return.

3. Summary and Conclusion to Decoupling Overview

Q. Please summarize your findings about decoupling.

A. For most of the past decade, 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 approach 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 a number of LDCs in a number of states have adopted decoupling mechanisms over the last decade, there is now a rich source of data 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 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 at this time. Specifically, I will:

- Describe EnergyNorth's EE programs and demonstrate that EnergyNorth's level of involvement in and support for EE programs warrants the implementation of an RDM to remove the financial penalties that the Company incurs by continuing to allocate the resources and management attention that is required to provide effective energy efficiency programs to its customers, in support of the State's energy efficiency goals and objectives.
- Describe and explain EnergyNorth's recent customer and revenue per customer trends.

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

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

A. EnergyNorth has been offering Energy Efficiency programs to its customers since 2003 that provide rebates and technical support for residential and commercial customers who seek to minimize their energy use.

Table 4 below provides a summary of the direct energy savings that have resulted from EnergyNorth's EE programs.

Table 4: EnergyNorth Energy Efficiency Program Savings (Annual Dth)

Year	Residential	C&I	Total Energy Savings	Cumulative Post Test Year Energy Savings
2006	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	78,227
2011	29,281	46,466	75,747	153,974
2012	39,702	108,565	148,267	302,241
2013	40,510	74,831	115,341	417,582
2014[14]	34,125	59,817	93,942	511,524

The estimated 2014 cumulative Post Test Year EE savings provided in Table 4, 511,524 Dth, can be used to develop a straightforward demonstration of the impact of the Company's EE programs on EnergyNorth's revenues and return. Table 5 below shows that the Company's 2014 revenues would be greater by over $1

14 Forecast

million but for the energy savings resulting from the Company's EE programs; the $1 million in foregone revenues represents about 1.9% of Test Year revenues.[15]

Table 5: EnergyNorth Energy 2014 Efficiency Program Foregone Revenues

	Residential	Commercial	Total
Cumulative 2014 EE Therm Savings	1,871,420	3,243,820	5,115,240
Average 2014 variable rate per therm	$0.2616	$0.1690	
Total EE Foregone Revenues	$489,563	$548,206	$1,037,769

Q. Does the EE program incentive payment that EnergyNorth earns offset the foregone EE revenues?

A. No, the EE incentive payments do not offset EnergyNorth's foregone EE revenues. EnergyNorth is eligible to receive annual EE incentive payments of from 0% to 12% of annual EE program spending, assuming the Company's performance in providing the programs meet the standard for the shareholder incentive. This 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." Energy Efficiency Programs for Gas and Electric Utilities, Order No 24,203, 88 NH PUC 401, 405 (2003). For example, the Company's 2013 EE program incentive payment was $457,341[16] yet the cumulative 2014 foregone revenues were $1,037,769 as shown in Table 5. Thus, the Company lost $580,428 as a result of encouraging its customers to use less natural gas.

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15 Cumulative 2014 foregone revenues as a percent of 2013 TY proforma revenues = $1,037,769 / $55,208,061 = 1.9%.

16 Pending final PUC audit review and authorization.

This is a clear demonstration of the merits of an RDM to decouple EnergyNorth's revenues and earnings from the volumes of gas that the company delivers so that EnergyNorth's efforts to promote energy efficiency are not in direct conflict with its financial well-being.

Q. Do you have any information on the future direction of the Company's EE programs?

A. I am aware that New Hampshire is considering enhancements to state energy policy and regulations to "… help stimulate investments in energy efficiency and further develop a competitive marketplace in the state."[17]

The November 15 Report to the NH OEP sets as a key objective the "… development of a state-level policy that sets specific energy savings targets, establishes a timeline for achieving the targets, and assigns authority and oversight to the appropriate public entity."[18] The Company anticipates that this state-wide policy, referred to as an Energy Efficiency Resource Standard (EERS), will result in increased EE savings targets for EnergyNorth's EE programs.

EnergyNorth's proposed RDM in this proceeding will be an important factor that will allow EnergyNorth to strongly advocate for EE programs with targets that are

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17 Increasing Energy Efficiency In New Hampshire: Realizing Our Potential, Final Report to New Hampshire Office of Energy and Planning (NH OEP), November 15, 2013.

18 Final Report, page 7

likely to be ramped up from current target levels.

C. 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 will discuss trends in EnergyNorth's normalized use per customer ("UPC") and number of customers, starting in 2003. I will provide summary analyses that I prepared for the following customer groups: (a) Residential; (b) C&I and (c) total Company. I prepared separate analyses for residential and C&I Customer Groups, because customers in these two groups have generally behaved very differently over the period of analysis, 2002 to 2013. I will also offer high level explanations for the changes in deliveries, customers and use per customer that Energy North has experienced in the past several years.

2. Analysis of UPC and Customer Trends

Q. Please summarize the trends in EnergyNorth's weather normalized Use per Customer that you have identified.

A. To identify trends in EnergyNorth's UPC, I prepared Residential, C&I and Total Company UPC graphs; these graphs are provided in Attachment JDS/DECPL-1. The first graph in Attachment JDS/DECPL-1 shows that Normalized UPC for the

Residential customer group declined 15.9% during the period of analysis, from 916 therms per customer in 2002 to 771 therms per customer in 2013. However, between 2002 and 2008, the rate of decline was 13.7 percent; between 2008 and 2013, UPC decreased by 2.2 percent.

The second graph in Attachment JDS/DECPL-1 shows a very different story for the C&I customer group. Over the entire 2002 to 2013 period, C&I UPC increased from 8,542 therms to 8,873 therms, an increase of 3.9% percent; between 2002 and 2008, C&I UPC increased by 2.2% percent, and between 2008 and 2013, C&I UPC increased by 1.7% percent.

The third graph in Attachment JDS/DECPL-1 shows that Total Company UPC decreased by 1.9% percent, which indicates that overall, the increasing C&I UPC offset much of the decreasing Residential UPC over the entire period.

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 JDS/DECPL-2. The first graph in Attachment JDS/DECPL-2 shows that the number of residential customers increased by 15.5 percent during the period of analysis, from 65,616 customers in 2002 to 75,806 customers in 2013. Customer growth was greater from 2002 to 2008, (11.6 percent) than from 2008 to 2013 (3.9 percent).

The second graph in Attachment JDS/DECPL-2 shows that the number of C&I customer customers increased by 22.6 percent during the period of analysis, from 9,105 customers in 2002 to 11,166 customers in 2013. Customer growth was greater from 2002 to 2008, (17.4 percent) than from 2008 to 2013 (5.2 percent).

The third graph in Attachment JDS/DECPL-2 demonstrates that the overall Company customer growth reflects the relatively robust growth in Residential and C&I customers between 2002 and 2008, and the moderate customer growth between 2008 and 2013; Total Company customers grew by 12.3 percent from 2002 to 2008; 4.1 percent between 2008 and 2013, and by 16.4% for the entire 2002 – 2013 period.

3. Explanation for UPC and Customer Trends

Q. Can you provide an explanation for the overall differences in the Residential and C&I UPC trends that you observed?

A. Although I have not performed a statistical analysis of the factors that affect EnergyNorth customer usage patterns or the number of EnergyNorth customers, I am familiar with the factors that are likely to have influenced the UPC and customer trends that I observed because I have prepared demand forecasts for several gas LDCs in New England.

Based on this experience, I believe that the most significant economic factors that affected the Company's customer and UPC 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 that occurred in the past four or five years, 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[19]; and (d) the long term price advantage that gas has over oil, caused by the large increase in gas supplies from shale formations.

In addition to the economic factors that affected EnergyNorth's UPC over the past decade, there are other, structural, impacts on UPC over this period that include (a) the impact of energy efficiency improvements for gas equipment, as a result of tighter governmentally-imposed minimum standards or technological

[19] 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.

improvements that gas equipment vendors adopt to remain competitive; (b) increased awareness of benefits of conservation and (c) perhaps, a long term trend of fewer occupants per dwelling unit.

To demonstrate the impact of gas prices on the Company's UPC over the past several years, I have prepared Attachment JDS/DECPL-3, which shows the recent history of EnergyNorth COG rates on an annual basis, and Attachment JDS/DECPL-4, which shows the recent history of EnergyNorth annual average COG rates on a monthly basis. The decrease in COG rates since 2008, which is at least 40 percent, depending on the customer group, has likely had a positive effect on EnergyNorth's UPC during this period.[20]

I believe that the decrease in Residential UPC in the first half of the period was caused by customer conservation efforts in response to (a) the high gas prices in 2005 – 2006; and (b) the recession, which reduced customers' incomes and wealth.[21] In addition, I believe that the relatively stable residential UPC for the past five years indicates that the increase in usage that would be caused by the recovery

[20] That is, if EnergyNorth COG rates had been constant or increasing during this period rather than decreasing by at least 40 percent, the UPC growth rates would have been lower than the actual growth rates that are summarized in Attachment JDS/DECPL-3.

[21] 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.

from the recession and the dramatic decrease in gas costs has been largely balanced by the continuing impact of energy conservation. Residential Customer and UPC 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 gas has had over oil in recent years.

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

	Residential Delivered Cost per therm		
	Distillate Fuel Oil	Natural Gas	Oil Price Premium
2011	$2.68	$1.40	92.2%
2012	$2.72	$1.35	101.8%
2013	$2.69	$1.22	119.8%

I believe that the increases in C&I customers and UPC 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 that gas has over oil; and (b) new C&I customers also converting to gas equipment, especially on-the-main energy users.

4. Summary and Conclusion

Q. In Section III.C of your testimony, you explained that a key justification for decoupling is that during periods when LDCs are experiencing persistent declines in use per customer, an RDM is an appropriate modification to traditional ratemaking. However, the analysis that you presented in Section

IV.C.3 demonstrates that the persistent decline in UPC that EnergyNorth had been experiencing ended in 2008. Please explain why the Company is proposing an RDM when the overall Company UPC has been flat for the past five years.

A. EnergyNorth is proposing an RDM at this time because (a) the conditions that have had a beneficial (increasing) effect on EnergyNorth's customer and UPC growth in recent years cannot be expected to continue indefinitely; (b) EnergyNorth expects that conservation efforts will continue to ramp up as a result of continued state and federal focus on energy efficiency programs; and (c) under all conditions, it remains the case that EnergyNorth's efforts to promote efficient energy uses are contrary to the Company's own financial interests.

The Company realizes that by implementing an RDM at this time, its revenues may be less in the short run if the UPC trends that have been experienced in the past few years (particularly last winter) continue beyond the test year. The Company believes that this RDM proposal is appropriate because, despite the potential for lower revenues in the near term, implementation of an RDM will have long-term benefits for the Company, its customers, and the state, which from a public policy perspective, has an interest in seeing overall energy use continue to decline.

Q. Please support your statement that "the conditions that have had a beneficial effect on EnergyNorth's customer and UPC growth in recent years cannot be expected to continue indefinitely."

A. As I have explained in this testimony, the conditions that have had the most significant beneficial effect on EnergyNorth's customer and UPC growth in recent years include (a) dramatic decreases in gas prices that occurred in the past four or five years; (b) the end of the economic recession in June 2009; and (c) the long term price advantage that gas has over oil, caused by the large increase in gas supplies from shale formations. As I will explain in the following section, these conditions are unlikely to continue to have a positive effect on EnergyNorth's customer and UPC growth in the upcoming years.

Q. Please support your statement that decreases in gas prices cannot be expected to continue indefinitely.

A. It appears that the decrease in gas prices that started in 2009 has generally ended. Attachment JDS/DECPL-4 demonstrates that the dramatic decreases in gas costs generally concluded by 2011, and gas prices have leveled off since 2011. For example in the 54-month period between February 2009 and August 2013, the annual average cost of gas to EnergyNorth residential customers decreased by 40%; 32% of that decrease occurred in the first 25 months, to March 2011, and the remaining 8% occurred in the 29 months from March 2011 to August 2013.

As further evidence that the trend of decreasing gas costs has concluded, I have prepared Attachment JDS/DECPL-5 to demonstrate that the forecast delivered cost of natural gas to residential customers in New England, is expected to increase at a moderate rate over the next few years; the Energy Information Administration projects that the delivered cost of natural gas in New England will increase by 4.7 percent between 2014 and 2020.

Q. How will the increase in gas prices that the EIA is predicting affect the gas usage of EnergyNorth's customers?

A. Customers generally respond to an increase in the price of a good or service – including natural gas – by decreasing their demand for that good or service; and in response to a decrease in price, customers generally respond by increasing their demand. Applying that economic principle to EnergyNorth's recent historical gas prices, it is likely that the Company's customers responded to the 40% decrease in gas prices that occurred between 2009 and 2013 by increasing gas usage. As demonstrated in Attachment JDS/DECPL-1, Residential UPC consistently decreased between 2002 and 2008, and remained relatively constant from 2008 to 2013; as a result, the likely customer response to the decrease in gas prices after 2009 does not appear to have completely offset energy conservation efforts that occurred during that period.

However, it is likely that falling gas prices was partly responsible for the increase in

C&I UPC that is shown in Attachment JDS/DECPL-1; however, since the increase in C&I UPC continued after gas prices leveled off, it appears that there are other significant forces that have had an impact on the recent C&I gas usage trends.

Q. Please support your statement that the effect of the end of the economic recession in June 2009 cannot be expected to continue indefinitely.

A. In addition to gas prices, EnergyNorth residential customers' demand for gas is influenced by factors such as household income; commercial and industrial customers' demand for gas is influenced by the demand for the products and services that these customers provide. The recession had a negative impact on customer demand for gas; the end of the recession and the start of the rising phase of the business cycle has had a positive impact on customer demand for gas. Eventually, however, the current - rising - phase of the business cycle will conclude, the economy will be back to full strength and the corresponding positive impact on growth rates of customer demand for gas will end.

Q. Please support your statement that the impact of the long term price advantage that gas has over oil cannot be expected to continue indefinitely.

A. I want to be clear that the long term price advantage that gas has over oil is expected to continue for many years, if not indefinitely. I have prepared Attachment JDS/DECPL-6 to show the price forecasts developed by the U.S. Energy Information Administration for natural gas and heating oil delivered to New

England residential consumers. As summarized in Attachment JDS/DECPL-6, residential oil service is expected to remain approximately 80 percent more expensive than comparable residential natural gas service for at least the next 25 years.

With that clarification, the long term price advantage that gas has over oil will likely have a somewhat reduced impact (compared to recent experience) on (a) the number of on-the-main potential customers that EnergyNorth adds; and (b) the average use per customer of current and potential C&I customers.

As energy users in Energy North's service territory became aware of the price advantage of gas[22], and that the price advantage was not temporary, (a) current EnergyNorth gas customers that also used oil equipment to meet some of their energy have been converting that oil equipment to gas[23]; and (b) on-the-main potential customers that were not EnergyNorth customers have requested to be connected to EnergyNorth's distribution system and have converted oil equipment to gas[24], if the cost of converting to gas equipment is economically feasible.

[22] The current long term price advantage of gas started in 2007 or 2008; energy users' recognition of that advantage appears to have lagged by several years.

[23] EnergyNorth customers converting oil equipment to gas would increase UPC.

[24] Energy users connecting to EnergyNorth's distribution would increase EnergyNorth's customers, and may increase or decrease EnergyNorth's UPC, depending on the gas use of that customer relative to the rest of the customer group.

It is likely that at some point in the near future, the impact of the price advantage of gas on EnergyNorth's on-the-main UPC and customer additions will have diminished because the remaining potential opportunities to convert to gas equipment have been decreasing (as potential customers became actual customers) such that conversions to gas equipment will no longer serve to offset the continuing long term impact on the Company's revenues per customer and earnings that is related to the Company's EE programs and customer conservation.

D. <u>Details of EnergyNorth's Decoupling Mechanism</u>

1. Introduction

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

A. The Company is proposing a Revenue per Customer ("RPC") decoupling mechanism that will be applied to all firm 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 describe how the following sections of your testimony are organized.

A. In the sections that follow, I will provide details to the general description of the Company's proposed RDM; where appropriate, I will provide support for the Company's proposed approach.

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

A. Taken together, the following components of EnergyNorth's RDM determine how the RDM will work, and the impact that the RDM has on EnergyNorth's customers and on EnergyNorth.

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
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 I stated in the introduction to this section, the Company's proposed decoupling mechanism is an RPC RDM. An RPC RDM is critical to providing the Company with some opportunity to earn a reasonable return between rate cases, from the revenue growth that is related to the growth in customers. Our RDM research indicates that RPC decoupling mechanisms are most common for gas LDCs, apparently because LDCs are experiencing significant customer growth that is related to the strong economic incentives that oil customers have to convert to gas. An 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 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) all 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, including the recently-approved CNG special contract, 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 7 below.

Table 7: RDM Customer Groups

RDM Customer Group	Firm Rate Classes
Residential Non Heating	R-1, R-2,
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 7, 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 JDS/DECPL-7 to provide a summary of the variability in normal revenue per customer for each of the C&I rate classes[25]. Attachment JDS/DECPL-7 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-53, and G-54. 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 JDS/DECPL-7 also demonstrates that the normal revenue per customer for all C&I rate classes combined is relatively stable. As a result, the seasonal calculated revenue shortfall or surplus for the combined C&I RDM customer group will not be affected the year (i.e. the rate case test year) that is used to determine the target RPC.

25 This analysis is based on the same actual and weather normalized billing determinant data that was used to prepare Attachment JDS/DECPL-8; monthly revenues are based on July 2014 rates, and R-4 revenues are calculated at R-3 rates. Additional discussion of the decoupling data base and analysis is provided in Section IV.D.10.

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 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 Rates-10.

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 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.

Actual revenues to be used in the RPC true up calculations will not be weather normalized. As I explained in Section III.D, our RDM research indicates that (a) the RDMs that have been implemented by 40 of the 51 LDCs eliminate weather related variability in revenues (to the LDCs) and bills (to the customers) because the RDM calculations determine RDM revenue shortfalls and surpluses on actual revenues; and (b) the RDMs that have been implemented by the other 11 LDCs do not eliminate weather-related variability in revenues and bills directly as part of the RDM calculations; however, each of these 11 LDCs has a separate weather normalization adjustment clause that eliminates weather-related variability. Altogether, therefore, all 51 LDCs have eliminated weather-related variability in revenues and bills.

7. Treatment of New Customers

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

A. The Company will include new customers in the RDM calculations. New customers will be charged the rate adjustments associated with the RDM and the calculations of actual revenues per customer will include the new customers.

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 5 percent cap on rate increases; that is, the RDM increase 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)[26]. Any excess over the 5 percent 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.[27]

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

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[26] EnergyNorth is not proposing a symmetrical limit on negative (credit) RDM adjustments, because the Company does not anticipate that large credits will develop. If large credits were to materialize, they would be refunded to customers during the next season.

[27] 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.

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 Revenue[28] 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

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

or returned in the same season prior period.

10. Additional RDM Details

Q. Will the Company's proposed RDM extend the time between the Company's future rate cases?

A. The Company's proposed RDM may have a limited effect on the time between the Company's future rate cases. The primary effect of an RDM is to make a marginal improvement in the opportunity that the Company has to earn a reasonable return, and to eliminate disincentives to continuing to be an active advocate for its energy efficiency programs.

My research indicates that a utility must have an effective cost recovery mechanism or rate plan that will account for inflationary pressures and the cost of additions to plant and rate base between rate cases as a condition for agreeing to "stay out" for a specified minimum period. An RDM alone does not account for inflationary pressures and the cost of additions to plant and rate base between rate cases.

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

A. Yes, I have prepared Attachment JDS/DECPL-8 for that purpose. To prepare Attachment JDS/DECPL-8 I used actual Company data for the period from January

2009 October 2013 to show:

- 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 2009 Test Year. Actual revenues for January 2009 through October 2013 and Normalized revenues for 2009 are based on 2014 rates.[29] The calculation of the Target RPC is provided in Attachment JDS/DECPL-8, page 1.
- The calculation of actual RPCs, RDM revenue shortfalls or surpluses per customer, and total revenue shortfalls or surpluses for Summer 2010 through Summer 2013 is provided in Attachment JDS/DECPL-8, pages 2 – 5.

Q. Please summarize the results of the analysis that is provided in Attachment JDS/DECPL-8.

A. I have prepared Table 8, below, to summarize the revenue shortfalls, by season, from Summer 2010 through Summer 2013.

29 All revenues are adjusted to 2014 rates to reflect a requirement of RDM calculations: for each RPC true up calculation, the Target RPC revenues will be adjusted to reflect the rates in effect during the months of that true up calculation period.

Table 8: RDM Summary and Impact Analysis

	Revenue Shortfall (Surplus) $				Shortfall / Surplus	
	R-1	R-3 R-4	C&I	Total	% of distribution revenues	per therm
Summer 2010	$5,552	$294,568	$206,722	$506,842	3.1%	$0.0135
Winter 2010 - 11	($1,492)	($572,492)	($791,326)	($1,365,310)	-3.7%	-$0.0120
Summer 2011	$3,028	$157,741	($41,823)	$118,946	0.7%	$0.0032
Winter 2011 - 12	$4,404	$1,874,640	$1,573,587	$3,452,632	10.4%	$0.0303
Summer 2012	$3,790	$286,842	$7,728	$298,360	1.8%	$0.0076
Winter 2012 - 13	($10,724)	$377,765	($79,376)	$287,665	0.8%	$0.0025
Summer 2013	$1,806	$220,652	($146,767)	$75,690	0.4%	$0.0019

Table 8 demonstrates that if an RDM had been in effect during this period, the RDM rate adjustment would have been a credit in one season, following the surplus revenues collected in Winter 2010-2011; the RDM adjustment would have been a charge in the other six seasons. The RDM rate adjustments would have been generally small; the shortfall or surplus would have been greater than two percent of seasonal distribution revenues in 3 seasons; the 5 percent customer impact cap would have been applied to the RDM rate adjustment in the winter following the 2011-2012 Winter; the amount of the shortfall in excess of 5% of distribution revenues would have been deferred, to be recovered in following winter periods.

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

A. I have prepared Attachment JDS/DECPL-9 to illustrate the timing of RDM calculations, filings and rate adjustments. Referring to Attachment JDS/DECPL-9, 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?

A. Yes. The Company's proposed Local Distribution Adjustment Clause ("LDAC"), which includes provisions for the RDM in Section XX of the LDAC, is included in the proposed tariffs in this proceeding. Section XX 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 XX also describes the documentation that the Company will provide with annual RDM filings.

Q. Does this complete your testimony?

A. Yes, it does.