215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (web site)

March 30, 2018

**PUBLIC DOCUMENT – NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

**RE: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota**
**Docket No. E017/GR-15-1033**
**Compliance Filing – Decoupling Report**

Dear Mr. Wolf:

Enclosed for filing in the above proceeding are Public and Not Public-Protected Data versions of Otter Tail Power Company's Decoupling Agreement, Analysis and Response and its attachments.

The information identified as Not Public Data in Attachment 3 contains the direct testimony of Dr. Mark Lowry, which was previously classified as Not Public Data per the non-disclosure agreement with Fresh Energy.

Please contact me at (218) 739-8350, or bboss@otpco.com, should you have any questions with respect to this filing.

Sincerely,

*/s/ BRIAN BOSS*
Brian Boss
Regulatory Administration, Pricing Analyst

jch
Enclosures
c: Service List
David Prazak
By electronic filing

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E017/GR-15-1033

**Decoupling Agreement, Analysis and Response**

March 30, 2018

## TABLE OF CONTENTS



## ATTACHMENTS

# I. INTRODUCTION

## A. Restate the agreement between Fresh Energy and Otter Tail Power

Otter Tail Power Company (OTP) and Fresh Energy have agreed to the following process designed to further assess the customer impacts associated with a potential revenue decoupling mechanism for OTP:

- OTP and Fresh Energy agree that decoupling will not be implemented at the conclusion of Docket No. E017/GR-15-1033.
- OTP commits to filing a report analyzing the potential customer impacts of Fresh Energy's proposed revenue decoupling mechanism. The report will be filed on or before April 1, 2018 and will include the following:
    - Comparison of actual 2017 revenues to 2017 baseline revenues (with baseline revenue per customer calculated using the final rates, sales and customer counts of this rate case) for the classes recommended by Fresh Energy (Residential, Farm, and Small General Service rate classes); and
    - Comparison of actual 2015 and 2016 revenues to 2009 baseline revenues (baseline revenue per customer calculated using the final rates, sales and customer counts from OTP's 2010 Rate Case (Docket No. E017/GR-10-239)) for the classes recommended by Fresh Energy.
- OTP and Fresh Energy envision that the Commission would initiate a notice and comment period on OTP's report.
- OTP and Fresh Energy anticipate the comments would address the customer impacts documented in the report.
- OTP and Fresh Energy also anticipate the comments will address whether OTP should be authorized to implement a decoupling pilot for the studied rate classes outside of a rate case.
- All interested parties would be invited to participate in the Comment process.

## B. Recap the testimony of Dr. Mark Lowry

Dr. Mark Lowry of Pacific Economics Group Research LLC, was engaged by Fresh Energy to evaluate Otter Tail Power incentives for small volume customers to adopt distributed energy resources (DERs) as well as demand side management (DSM) and distributed generation and storage (DGS). In his direct testimony, Dr. Lowry offered his views on what he considered poor incentives for utilities to embrace DER's using traditional regulation and then conducted an analysis of Otter Tail Power data to make the case for adopting an alternative regulatory system that was judged by Fresh Energy and Pacific Economics Group to be better suited for the promotion of DER's by Otter Tail Power to its customers. In making that case, Dr. Lowry described traditional utility regulation, introduced alternative regulation strategies ("alt reg") and elaborated on the following types of alternative regulation:

1. Revenue Decoupling
2. Tracking of DSM expenses
3. DSM performance incentives
4. Multiyear rate plans
5. Fixed/variable rate designs

Upon concluding the analysis, Dr. Lowry recommended that Otter Tail Power implement a revenue decoupling system that was broadly like one approved by the Minnesota Public Utilities Commission for Xcel Energy. In support of that recommendation, Dr. Lowry provided a financial model and illustrative tariff sheet.

## C. Report summary

This report contains the examination of two different test years against actual results of company operations for select years agreed to by Fresh Energy and Otter Tail Power. In addition to the agreed upon scope of the report, Otter Tail elected to analyze all the years between 2009 and 2017 in order gain a better understanding of how the decoupling mechanism would have worked during that time frame. Along with that analysis Otter Tail also performed an investigation into national decoupling examples from companies that possess certain similarities to Otter Tail Power. After examination of the decoupling analysis and taking the lessons learned from other decoupling implementations, Otter Tail evaluates the proposed decoupling model against criteria defined by the Commission. The evaluation provides a guide to what factors are necessary for successful adoption of a decoupling mechanism.

## II. EXAMINATION OF NATIONAL DECOUPLING EXAMPLES

Dr. Lowry introduces revenue decoupling in section 3 of Attachment 3 to his direct testimony in Docket No. E017/GR-15-1033. Section 3.1 introduces the concepts of the revenue decoupling mechanism (RDM) and revenue adjustment mechanism (RAM). Section 3.2 provides national context for the decoupling story, while table 3 contains a listing of states which had decoupling programs for both natural gas and electric utilities and the companies that were participating in them.

When considering the national context of decoupling, Otter Tail Power is specifically interested in learning more about electric utilities from the United States which have decoupling programs. Finding comparable companies is important to Otter Tail to be informed of any lessons learned in addition to studying the process the companies and state commissions went through to arrive at the decoupling implementation. Canadian companies and non-Minnesota natural gas utilities were not considered further, as there would be limited comparability to Otter Tail Power. Attachment 3 shows 26 companies from the United States that have electric only operations and two that have combined gas and electric operations. These 28 utilities will form the proxy group from which Otter Tail Power will draw upon the experience of companies with similar size and operating environments.

Inspection of the list reveals that 12 states are home to the 28 companies that have decoupled some form of their electric operations. As called out in section 3.2 of Dr. Lowry's direct testimony, California, Rhode Island, Massachusetts and New York have mandated revenue decoupling. California has five utilities in the Attachment 3 list and as described by Dr. Lowry, the state had several motivations for pursing decoupling, among them the bulk power market crisis of 2000 – 2001 and the desire to promote conservation.

Hawaii has three electric utilities listed in Attachment 3, with each of them being part of a joint docket, No. 2008 – 0274, opened in 2008. The Public Utilities Commission of the state of Hawaii initiated an investigation to examine decoupling for the three state utilities. The effort started in 2008 with a joint agreement between the Governor, the State of Hawaii Department of Business, Economic Development and Tourism, the State of Hawaii Division of Consumer Advocacy of the Department of Commerce and the Hawaii Electric Companies (HECO) that was designed to move the state away from its dependence on imported fossil fuels for electricity and ground transportation. According to the initial filing in this docket, the stakeholders wanted to migrate to “indigenously produced renewable energy and an ethic of energy efficiency”. This agreement is a product of the Hawaii Clean Energy Initiative with the following goals:

- Accelerating development of clean resource generation on all islands.
- Transition HECO away from a business model that encourages increased electricity use.
- Provide measures for customers to reduce their energy bills.

The Hawaii Clean Energy Initiative was created from a Memorandum of Understanding between the state of Hawaii and the U.S. Department of Energy which established a partnership with the goal of having 70 percent of the state electricity needs generated by renewable energy by 2030, while simultaneously protecting the sponsoring utilities financial health from erosion. The first implementation was scheduled to occur in Commission mandated rate cases by the HECO companies that were set to begin in 2009.

Massachusetts has three utilities listed in Attachment 3. The state electric utilities adopted decoupling because they were compelled to as elaborated on in docket D.P.U. 07-50-A. Massachusetts passed a state law called “An Act Relative to Green Communities”, Chapter 169 of the Acts of 2008 which promoted energy efficiency. (aka Green Communities Act). That act along with the actions of the Department of Public Utilities led to the decoupling adoption.

New York and Maryland, respectively, have five and three utilities listed in Attachment 3, effectively making all investor owned utilities in those states subject to revenue decoupling. When combined with Rhode Island, as mentioned previously, six states (California, Hawaii, Massachusetts, New York and Rhode Island) combine to host 20 of the 28 electric utilities that have adopted some form of decoupling. This heavy concentration of decoupling adopters in such a small number of states does not present a large proxy group of utilities for Otter Tail to study.

Otter Tail hoped to find similarly sized, vertically integrated, electric utilities (VIEU's) located in states where adoption is given due consideration, rather than being compulsory.

Given those circumstances, Otter Tail selected the following companies to study as they most closely resembled Otter Tail Power in either business operations or the state where business is conducted.

- Idaho Power Company
- Portland General Electric
- Northern States Power Company – Minnesota
- CenterPoint Energy
- Minnesota Energy Resources Corporation

Brief summaries of the companies decoupling adoption will be presented to illustrate their respective road to decoupling.

**Idaho Power Company**

**Case: IPC – E – 11 – 19**

**Why did they decouple?**

The evaluation started with docket IPC – E – 04 -15 which the Commission opened to investigate decoupling. The order from that docket was issued on March 12, 2007 and created a pilot project for "fixed cost adjustments" or FCA. The pilot project applied to residential and small general service customers. On October 1, 2009 the company applied to make the pilot program permanent, see case IPC-E-09-28. The request to make the program permanent was denied at that time by the Commission. Instead, the Commission extended the pilot another two years. The request to make the decoupling permanent was made again in docket IPC E-11-19 and was approved in that filing.

**What kind of decoupling is this?**

The company sets a fixed cost per customer which is then compared to the amount collected. The over/under collection is then subject to true up. One interesting thing to note is the Commission acknowledged the imperfections of identifying the source of the load reduction as being attributed to DSM programs or other outside forces. The Commission remedied this by allocating any incentives earned from identified savings as being split equally between the company and customer.

**What lessons can Otter Tail learn from this?**

Idaho Power (IP) had a very specific reason for wanting to decouple and that reason involved the recovery of fixed costs. The rate design for the company prior to decoupling was shifting the recovery of fixed costs into volume-based rates and subsequently it became very difficult to recover costs from the irrigation class for instance. According to the 2016 IdaCorp annual report, (the parent company of Idaho Power) approximately 13 percent of IP's revenue and 13 percent of the sales volume came from the irrigation class. At the same time that class only had three percent of the customers. When subsequently designing the mechanism, Idaho Power worked with the various stakeholders to implement the fixed cost adjustment (FCA) decoupling method and proved through the pilot period that it was a viable rate setting tool for Idaho Power and their customers.

**Portland General Electric Docket**:

Most recent approval was in order 13-459 (docket UE 262), while a request to resume was in order 09-176 (docket UE 197).

**Why did they decouple?**

Oregon has had a very interesting relationship with the concept of decoupling. Starting in 1992 with order number 92-1673, the Oregon Public Utilities Commission directed Portland General Electric (PGE) to develop a decoupling mechanism suitable to its circumstances. In 1995 in order 95-322, decoupling was approved for PGE. In 2002, in order 02-633, the Oregon Public Utilities Commission rejected a request from PGE to continue to decouple, citing "harm to the customer." PGE initiated another request in 2008 and while that request was granted in order 09-020, Oregon PUC staff argued against allowing decoupling  on the grounds that over collection of fixed costs would occur, limited energy conservation would be achieved as a third party, the

Energy Trust of Oregon, was responsible for administering those programs and there was an inordinate shifting of risk from shareholders to ratepayers.

**What kind of decoupling is this?**

PGE is using a system they call Sales Normalization Adjustment (SNA). This system is applied to residential and small non-residential customers. Large non-residential customers with loads of less than one average megawatt (MW) participate in a Lost Revenue Recovery (LRR) mechanism. Very large non-residential loads are not part of the decoupling plan.

The sales normalization adjustment compares weather adjusted distribution, transmission and fixed generation revenues that are collected on a per – kWh basis with those that would be collected using a fixed per-customer charge. The difference is accumulated in a balancing account and refunded/collected over a future period. The result is PGE receives revenues as if it had a flat distribution charge while customers continue to be billed on a per kWh basis.

**What lessons can Otter Tail learn from this?**

The PGE proceedings illustrate the importance of having all stakeholders in agreement on the purpose, process and implementation of the chosen decoupling mechanism. Over the twenty plus years that the proceedings occurred, the Oregon PUC first embraced, then rejected, and then approved a decoupling mechanism. The primary concerns when decoupling was rejected included; shifting business risk from the utility to the consumer, the lag in correcting over or under collected revenues would result in monthly bill volatility and associated intergenerational inequity, and reduced quality of customer service. Without uniform agreement and participation between the company and stakeholders, successful decoupling implementation is made much harder.

**Northern States Power Company - Minnesota (Xcel Energy)**

**Docket No. :** E00**2/**GR 13-868

**Why did they decouple?**

Xcel witness Daniel Hansen (Ph.D.) listed three reasons to pursue decoupling. First, declining natural gas prices have reduced the benefits associated with pursuing conservation of electricity, while at the same time the conservation program costs are rising. Second, higher lighting efficiency because of the Energy Independence and Security Act (EISA) has made reaching conservation program goals more difficult. Finally, Xcel has been experiencing reductions in usage per customer in the residential and small commercial categories over the years preceding the filing. That trend was expected to continue and in the absence of decoupling would lead to downward pressure on utility revenues.

**What kind of decoupling is this?**

Xcel proposed to use a revenue-per-customer (RPC) mechanism that removes the effect of weather from the decoupling deferrals.

**What lessons can Otter Tail learn from this?**

The first item is gaining familiarity with how the revenue per customer model works, as the one suggested by Dr. Lowry is essentially what is being used by Xcel. Otter Tail notes that the accuracy of Xcel's test year billing determinants allow the company to stay within the permitted recovery bandwidth. In the 2017 Decoupling Annual Report, Docket Nos. E002/GR-13-868 and E002/GR-15-826, Xcel reported that only a single class, residential space heating, exceeded the three percent collection recovery band width.

**CenterPoint Energy**

**Docket:** G-008/GR 13-316

**Why did they decouple?**

CenterPoint was facing challenges in the following areas; weather variability and warmer temperatures, declining use per customer as well as the ongoing energy efficiency and conservation efforts of their customers. CenterPoint realized that those factors along with rising fixed cost charges necessary to support infrastructure maintenance and upgrades was making appropriate rate setting increasingly difficult. At that point, CenterPoint didn't feel rates could be set appropriately under the existing construct and they asked to be decoupled so they didn't have weather variability harming sales and related cash collection. In 2009 CenterPoint was partially decoupled on a pilot basis. The partial decoupling did not sever the link between sales and weather. In July 2012 the Minnesota Public Utilities Commission approved a “full” revenue decoupling mechanism for Minnesota Energy Resources Corporation (MERC). MERC’s full decoupling was described as “symmetrical” because it adjusts a utility’s rates for the effects of both energy efficiency and weather that varies from the normal weather assumed for regular rate making purposes. “Partial” decoupling on the other hand is asymmetrical because it computes rate adjustments only for energy efficiency and conservation related usage changes and does not adjust for weather variations. CenterPoint’s partial decoupling rider ended June 30, 2013 after a thirty-six-month pilot program. CenterPoint elected not to renew the pilot and instead filed a rate case to request moving to full decoupling. During the case the company could not come to agreement with the intervenors and during the evidentiary hearing, the Department withdrew support for the company decoupling proposal. After learning about the withdrawal during the evidentiary hearings, the Company stated that it would no longer seek approval of a decoupling mechanism in this case. In CenterPoint’s opinion, no decoupling was better than bad (partial) decoupling. In oral arguments to the Commission however, the company stated that it still supported full decoupling and stood by its decoupling related testimony. The Commission decided to allow CenterPoint full decoupling as a pilot project.

**What kind of decoupling is this?**

CenterPoint was finally allowed “full” decoupling that incorporated weather normalization.

**What lessons can Otter Tail learn from this?**

The form of decoupling that is chosen and implemented can be crucial to the success of the program in allowing the utility to achieve the targeted revenue recovery while at the same time supporting promotion of energy efficiency measures. The form of the decoupling mechanism must match company and customer parameters to provide the maximum benefits.

**Minnesota Energy Resources Corporation (MERC)**

**Docket:** G-007, 011/GR-10-977

**Why did they decouple?**

In 2007, a Minnesota state statute was passed that directed the PUC to set up pilot programs to decouple. MERC decided to file a proposed decoupling plan without elaborating on the reasons for doing so other than to refer to the state statute.

**What kind of decoupling is this?**

MERC was authorized to implement a pilot program using “full” decoupling that incorporated weather normalization.

**What lessons can Otter Tail learn from this?**

Otter Tail drew no conclusions about the efficacy of MERC’s decoupling mechanism other than it must have been well thought out and capably implemented because there did not appear to be objections or protests being registered. Perhaps this is the finest compliment that can be paid to a decoupling initiative.

**Summary of Lessons Learned**

First, determine the reason for implementing decoupling. Idaho Power demonstrated with the right reasons and cause for action, decoupling can be successfully implemented. Second, make sure all stake holders want decoupling and understand want the impact will be. The case of the Oregon Public Utilities commission and Portland General Electric illustrated what happens if all parties are not in agreement on how decoupling can be successful. Third, have the proper starting point as it relates to sales and associated revenues. From Xcel Energy, Otter Tail observed how representative test year determinants can facilitate the proper level of revenue recovery. Fourth, the company needs to have the right mechanism for both the customer and the company. CenterPoint’s case illustrates how important the form can be in facilitating proper function. Finally, Otter Tail noted that if all these components are present and properly implemented, decoupling should present a relatively innocuous and benign change to customers and the company.

# III. EVALUATING THE FRESH ENERGY PROPOSAL ACCORDING TO MINNESOTA PUBLIC UTILITY COMMISSION ORDER IN DOCKET NO. E,G999/CI-08-132

Otter Tail Power agreed to look at the revenue per customer model that Dr. Mark Lowry of the Pacific Economics Research submitted and provide two different comparisons. First, a comparison of actual 2017 revenues to 2017 baseline revenues (with baseline revenue per customer calculated using the final rates, sales and customer counts of this rate case) for the classes recommended by Fresh Energy (Residential, Farm, and Small General Service rate classes). Second, a comparison of actual 2015 and 2016 revenues to 2009 baseline revenues (baseline revenue per customer calculated using the final rates, sales and customer counts from OTP's 2010 Rate Case (Docket No. E017-GR-10-239)) for the classes recommended by Fresh Energy.

That analysis has been completed and as shown in Attachment 1. Otter Tail will evaluate the results of this analysis per the criteria laid out in the order for Docket No. E,G – 999/CI-08-132, "Order Establishing criteria and standards to be utilized in pilot proposals for revenue decoupling", dated June 19, 2009 beginning at page 7.

1. Purpose
2. Form
3. Cost of Capital
4. Classes Included
5. Mechanics
6. Service Quality
7. Review
8. Pilot Implementation

## A. Criteria 1

<u>Purpose:</u> All utilities shall state how their proposed decoupling mechanism adheres to the guiding statute. Each utility shall explain the purpose of the mechanism in the context of the

Next Generation Energy Act of 2007's energy savings goals and how their mechanism will further the state policy of increased conservation investment.

The decoupling mechanism proposed by Fresh Energy is modeled after one implemented by Xcel Energy which is a pilot program that has been approved by the Minnesota Public Utilities Commission in docket No. E002/GR-13-868, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, page 71 (May 8, 2015). The purpose of the mechanism is to remove the Company's disincentive to promote conservation and energy efficiency for residential, farm, small general service and general service customers.

### B. Criteria 2

Form: All utilities shall state the form of decoupling proposed and the purpose behind such choice. This should provide a detailed definition of what types of sales changes are included in the mechanism, i.e. weather-related sales changes, declining use per customer, etc., and the reason for such inclusion.

The form of revenue decoupling proposed is the revenue-per-customer model that has been approved in Xcel Energy's pilot program. This model effects "full decoupling" and will be applicable for the two service baskets defined by Dr. Lowry: Residential and Farm as well as General Service. According to the model defined for Otter Tail to evaluate, no customer charges will be included in the revenue collection and base rate collection of fuel and Conservation Improvement Program (CIP) charges will be removed. The full decoupling adoption also removes the impact of weather on sales and declining use per customer.

### C. Criteria 3

Cost of Capital: Otter Tail chooses to reference several published reports that discuss the impact of decoupling on the cost of capital. First, "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations" that was authored by Pamela Morgan and initially published in December 2012 and later updated in February 2013. Ms. Morgan concludes in her report that adopting a decoupling mechanism does not reduce the risk to a utility and subsequently warrant a reduction in the return on equity[1]. The second report is from the Brattle Group titled "The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation" and was released in March 2014. The conclusion of the authors was that adopting decoupling did not reduce utility risk and warrant a reduction in the return on equity[2]. Finally, Otter Tail references the testimony of Dr. Robert Hevert for Xcel Energy in docket No. E002/GR-13-868, Hevert Direct. On page 51, Dr. Hevert states that the adoption of decoupling by Xcel would not substantially lower the risk profile and lead to a lower return on equity. There is a mature, multi-decade record of testimony related to the cost of capital for decoupled utilities and Otter Tail cannot substantially add to that body of knowledge and advocates for a negligible impact to the cost of capital.

**D. Criteria 4**

<u>Classes Included:</u>

Per the agreement with Fresh Energy, Otter Tail looked at the Residential and Farm as well as General Service classes within the following parameters:

- Decoupling would apply to residential, farm, and general services (excluding large general services).
- Separate service baskets would apply to residential and farm services and to general services. The use of multiple baskets protects customers in each basket from rate adjustments resulting from the demand trends of dissimilar customers.
- The proposed RDM would adjust all usage charges in a given service basket equi-proportionately. Charges that fluctuate only with the number of customers (e.g., customer charges) would not be included in the RDM, as revenue collected through them is already decoupled from usage.

---

[1] 1 A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations. Morgan, Pamela. Page 17.

[2] The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation. Vilbert, M., Wharton, J., Gibbons, C., Rosenberg, M., Neo, Y. Page 21.

- The RDM would affect *full* decoupling subject to the constraint that surcharge adjustments due to the revenue decoupling system would be capped at 3% annually.
- Residual revenue variances would be eligible for true-up in the following year.
- Revenue per customer would be decoupled, so that the revenue requirement of each service basket rises gradually with the number of customers in that basket.
- Decoupling adjustments would be applied in each month of the following April-March period.

**E. Criteria 5**

Mechanics: All utilities must provide precise detail on how the decoupling mechanism will operate, with the understanding that any decoupling pilot program be transparent and easy to follow from a customer perspective. Details to be provided are as follows:

a) How the rate adjustment will be calculated.

Otter Tail will make class modifications to the Xcel approach because Otter Tail does not have a residential space heating class and labels as General Service and Small General Service what Xcel calls small Commercial and Industrial non-demand customers. Another difference is that Otter Tail will include the residential demand control service rate, which has a demand component, as agreed to with Fresh Energy. Finally, as noted in by Dr. Lowry on page 73, footnote 57, the Otter Tail method will include calculating the revenue per customer, not revenue per kWh. Fresh Energy was concerned that would incent Otter Tail to shift sales from low rates to higher rates. Otherwise, like Xcel Energy, Otter Tail would follow the method described by Daniel Hansen, Ph.D., who described the Xcel method in docket number E002/GR-13-868[3].

> "The Company does not propose to apply a carrying charge on deferrals. At the end of a 12-month period, the total deferral for each customer group will be divided by the forecast of sales to that group for the coming year. The resulting charge will be added to or subtracted from the customer group's volumetric rate for the following 12 months."

[3] Docket No. E002/GR-13-868, Hansen Direct, page 16.

b) When the rate adjustments will be made.

Per the Lowry direct testimony, page 71, decoupling adjustments would be applied in each month of the following April- March period.

c) Will a rate cap be present to mitigate the risk of rate shock?

Yes, per the Lowry direct testimony, page 71, "the RDM would effect full decoupling subject to the constraint that surcharge adjustments due to the revenue decoupling system would be capped at 3% annually. Residual revenue variances would be eligible for true-up in the following year".

d) What portion of the customer's bill will be impacted by the true-up?

Otter Tail would adjust the volumetric rate.

e) How will the adjustment be displayed on the customer's bill?

Otter Tail cannot answer that question at this point but does take into consideration the suggestion made by Fresh Energy and Dr. Lowry regarding the proposed tariff sheet.

f) Length of the pilot

Any implementation would follow the mandatory thirty-six-month pilot program length.

g) How will the decoupling rider work in concert with other automatic recovery mechanisms or financial incentives?

Otter Tail anticipates no interference between a decoupling rider and other riders that are present currently.

**F. Criteria 6**

Service Quality:

Otter Tail expects no adverse impact on the quality of service it provides to its customers.

## G. Criteria 7

Review: Otter Tail offers the following commentary and response to the agreement reached with Fresh Energy. First, a comparison of 2017 actual results to the 2016 test year was made. Second, an evaluation of the 2015 and 2016 results to the 2009 baseline revenues is provided with commentary.

## H. Criteria 8

Pilot Implementation: This not applicable as Otter Tail has not taken the step to agree to or institute a pilot program.

Prior to evaluating the results, several key points must be established. First, OTP notes that the 2009 test year was an historic test year that was filed in March of 2010. Knowing this, one must remember that the actual rates in place during 2009 were approved from the rate case that was filed in 2007. When responding to the agreement request to analyze 2009 actual results against 2009 test year, this must be kept in mind because of the impact it has on the actual revenue.

Second, Otter Tail chose to extend the analysis from 2009 through 2017. The extra detail is intended to bring additional depth to the response to the Fresh Energy agreement.

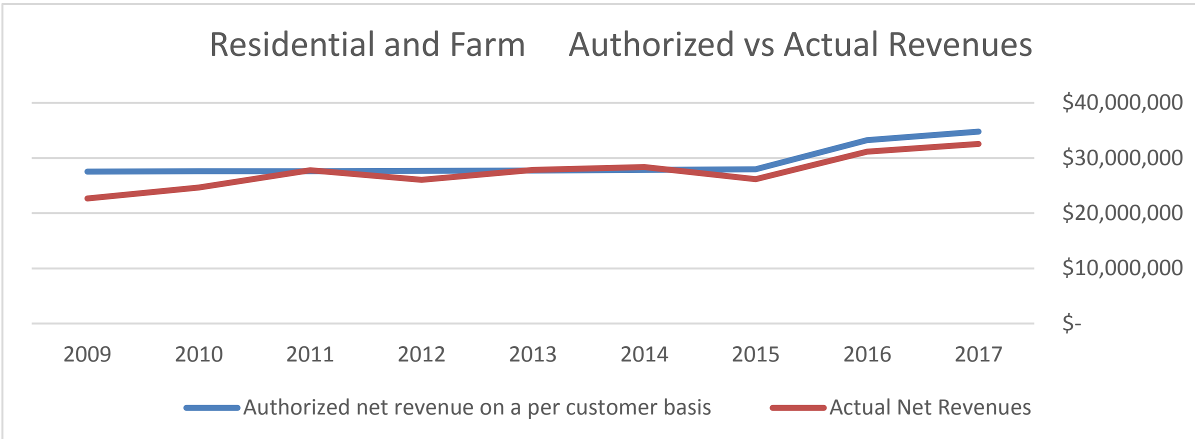
Third, during the 2009 through 2017 timeframe there was a mixture of final rates from the 2007 rate case, interim rates from the 2010 case beginning in 2010 and extending into September of 2011 and lastly, final rates from the 2010 rate case. In order standardize evaluation of the model, Otter Tail elected to insert final rates into the period in which interim rates were collected. This facilitated a consistent revenue stream and clarity in evaluating the results. That decision negated having to calculate an interim rate collection and subsequent one-month lump sum refund that would skew the results of the model.

Finally, the impact of overall revenue adjustments from the residential demand control service rate is addressed through adjusting the rate per kilo-watt hour. The revenues derived from demand sales on a kW basis do not significantly sway any conclusion reached in this evaluation.

**Evaluation of the results for the Residential and Farm Classes**

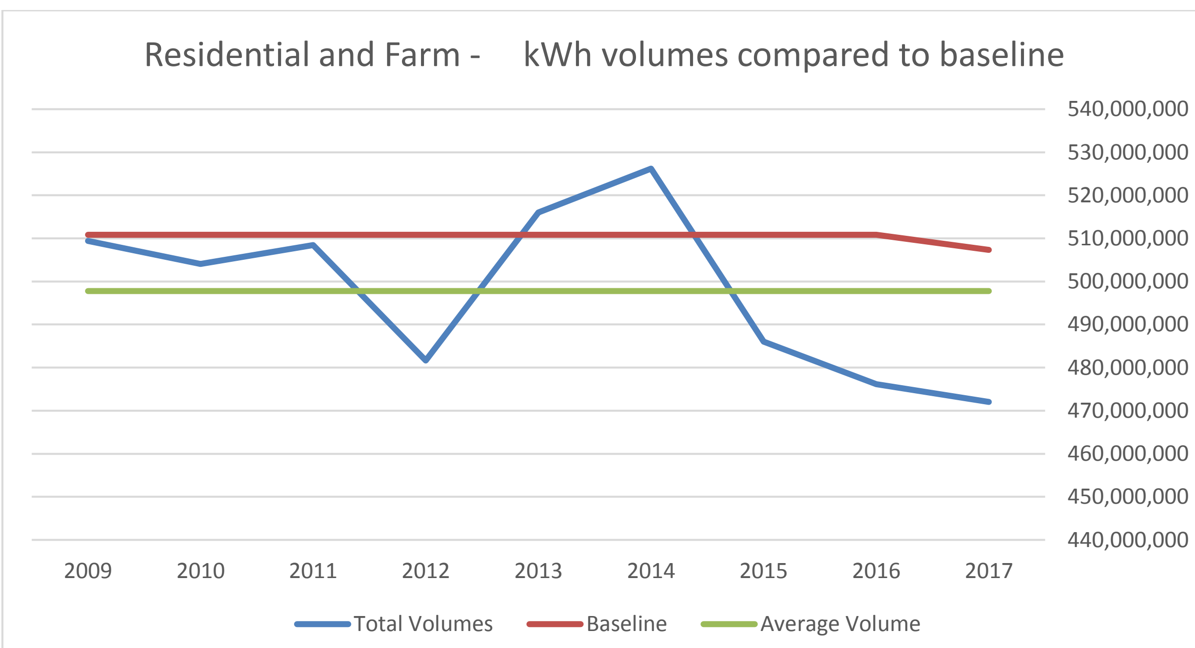
Looking at the results from 2009 through 2017, it can be observed that actual revenues rarely exceeded the allowed revenue per customer during that time frame. The graph below shows the comparison for that time period:

**Graph 1:** Residential and Farm revenues 2009 through 2017



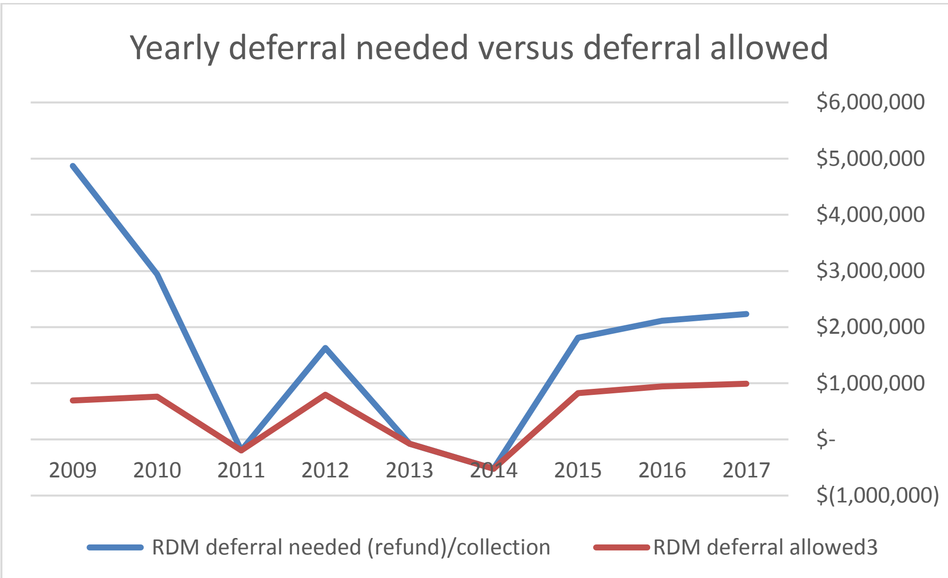

At the same time, inspection of the sale volumes in graph 2 shows that only during the polar vortex winter of 2013 through 2014 did actual volumes exceed the level agreed to in the test year.

**Graph 2:** Residential and Farm sales volumes 2009 through 2017



With that background in mind, we can anticipate there will be a difference in the revenue recovery which needs to be collected in future periods versus what will be allowed per the 3% revenue cap. That difference is shown in graph 3.

**Graph 3**: Residential and Farm RDM deferral balance




The evaluation will continue by looking at the 2009 test year and how that compares to 2009 actual results, which is shown in Table 1. Comparison of 2009 actual results against 2009 test year billing determinants shows that an under collection of $4,869,795 occurred. The deficiency was primarily related to the rates being too low because 2009 rates were still being impacted by the sales level set in the 2007 rate case. Interim rates from that case were still in effect in January 2009 with final rates from that case commencing in February 2009.

The decoupling impact to the company for the residential and farm classes for 2009 is substantial. The three percent customer impact is capped at a revenue adjustment of $694,933 while the sales shortfall was $4,869,795, leaving the company deficient $4,174,862. The final comparison for 2009 is seen in Table 1. The customer impact would have been capped at a rate increase of $1.18 per customer. The company, however, needed a rate increase of $8.24 per customer to achieve the revenue requirement for that class.

**Table 1**

Residential and Farm Classes - Comparison of 2009 Test Year to 2009 Actual Results

| RDM Adjustments | Source | Unit | Step | 2009 |
|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 4,869,795 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 694,933 |
| Deferral difference | Calculated | | C (A - B) | 4,174,862 |
| Cumulative Deferral | Calculated | | Prior balance + Current | 4,174,862 |
| Cap on Customer RDM Surcharges | Tab 5 - res & farm RDM | $ | D | 694,933 |
| Forecasted Volume: April - March | Tab 5 - res & farm RDM | kWh | E | 508,085,032 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001368 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.009585 |
| Total Volumes | Tab 5 - res & farm RDM | kWh | H | 509,435,858 |
| Total Customer Served - month | Tab 5 - res & farm RDM | | I | 592,395 |
| Volume per customer | | kWh | J(H/I) | 860 |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 1.18** |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 8.24** |

Moving to Table 2, a comparison will be made of the 2009 test year rates with the actual 2009 volumes. Here we can see a much more reasonable result, however, the company is still not falling within the revenue adjustment band width as $203,682 would be deferred until the next collection period. Before moving on, reflection upon these results confirms that the company was revenue deficient in 2009 and needed to return for a rate case in Minnesota in 2010.

**Table 2**

Residential and Farm Classes - 2009 Test Year Rates Using 2009 Actual Volumes

| RDM Adjustments | Source | Unit | Step | 2009 |
|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 986,000 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 782,319 |
| Deferral difference | Calculated | | C (A - B) | 203,682 |
| Cumulative Deferral | Calculated | | Prior balance + Current | 203,682 |
| Cap on Customer RDM Surcharges | Tab 5 - res & farm RDM | $ | D | 782,319 |
| Forecasted Volume: April -March | Tab 5 - res & farm RDM | kWh | E | 508,085,032 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001540 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.001941 |
| Total Volumes | Tab 5 - res & farm RDM | kWh | H | 509,435,858 |
| Total Customer Served - month | Tab 5 - res & farm RDM | | I | 592,395 |
| Volume per customer | | kWh | J(H/I) | 860 |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 1.32** |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 1.67** |

Upon implementation of interim rates in 2010, revenue did increase, however, revenues did not exceed the test year level as the volumes continued to decline from the test year. As noted earlier, to mitigate the impacts of interim rates and subsequent refund, Otter Tail used final rates for the period in which interim rates were in effect. By using final rates, Otter Tail was able to smooth the revenue stream by removing interim rate impacts. The result provides a clearer picture of what is happening within the decoupling model.

Falling sales volumes continued to play a role by impacting recovery bandwidth. From 2009 through 2015, only three of the years had an over- collection, 2011, 2013 and 2014. 2011 and 2013 had minor over-collections, while 2014 had a more substantial over-collection. The winter of 2013 – 2014 was abnormally cold and higher volumes drove the over collection. The remaining four years from 2009 through 2015 had a under collection. If each year within that period was considered in isolation, the non-compounded, cumulative deferral is $10,591,000.

When considering the impact of sales on decoupling, one point that stands out is the importance of setting the test year sales level correctly. Having sales volumes that are too high corresponds with setting rates too low. The low rates will not allow the utility the opportunity to stay within the bandwidth because there is not enough volume to achieve the revenue requirement target leaving the utility in the position of continually requesting permission to recover the deferred amounts. Even if the 2009 actual volumes were used in conjunction with 2009 test year rates as a starting point to evaluate 2009 through 2017, the cumulative deferral would still have been $6,619,820.

After establishing the background for the 2009 test year and 2009 actual results, the agreement with Fresh Energy required an evaluation of that test year against 2015 and 2016 actual results, which is shown in Table 3. Model results again show an under collection for both of those years. 2015 needed an additional $1,813,604 in revenue, of which $991,001 needed to be carried forward to a future period. 2016 needed an additional $2,115,125 in additional revenue, of which $945,093 needed to be carried forward to a future period. In 2016, Otter Tail filed another rate case, with interim rates starting April 16th of 2016. Following a similar approach as used for the 2010 case, Otter Tail chose to insert final approved rates from April 16, 2016 forward. Therefore, April of 2016 has a blended rate with the remaining months being the final rates that were approved in 2017. Even with the higher rates, the sales volumes are not sufficient to meet the revenue targets. The table on the following page shows the impact.

**Table 3**

Residential and Farm Classes - 2015 And 2016 Actual Results Compared to 2009 Test Year

| RDM Adjustments | Source | Unit | Step | 2016 | 2015 |
|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 2,115,125 | 1,813,604 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 945,093 | 822,603 |
| Deferral difference | Calculated | | C (A - B) | 1,170,031 | 991,001 |
| Cumulative Deferral | Calculated | | Prior balance + Current | 9,349,419 | 8,179,388 |
| | | | | | |
| Cap on Customer RDM Surcharges | Tab 5 - res & farm RDM | $ | D | 945,093 | 822,603 |
| Forecasted Volume: April - March | Tab 5 - res & farm RDM | kWh | E | 475,098,024 | 483,573,678 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001989 | 0.001701 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.004452 | 0.003750 |
| Total Volumes | Tab 5 - res & farm RDM | kWh | H | 476,120,562 | 486,058,050 |
| Total Customer Served - month | Tab 5 - res & farm RDM | | I | 605,207 | 602,129 |
| Volume per customer | | kWh | J(H/I) | 787 | 807 |
| | | | | | |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 1.56** | **$ 1.37** |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 3.50** | **$ 3.03** |

Now the evaluation will turn to examining the impact of 2017 actual revenues to the 2016 test year, which is referred to in the Fresh Energy agreement as “2017 baseline revenue”. Starting with the Residential and Farm classes, inspection of the models results in Table 4 show a $2,233,163 deferral necessary for full revenue recovery, but the deferral cap is $991,583 resulting in a roll forward amount of $1,241,581. Again, inspection of the model shows that, with one exception, actual sales volumes never rise to level set in the test year. The lone exception is the farm service rate, but that single class makes up less than 10% of the total volume. Residential sales are much of this category and they fall short of the baseline target, which subsequently drags down the entire class. In terms of the rate impact to the customer, the allowed rate is $1.54 per customer, while the required rate is $3.47 per customer.

**Table 4**

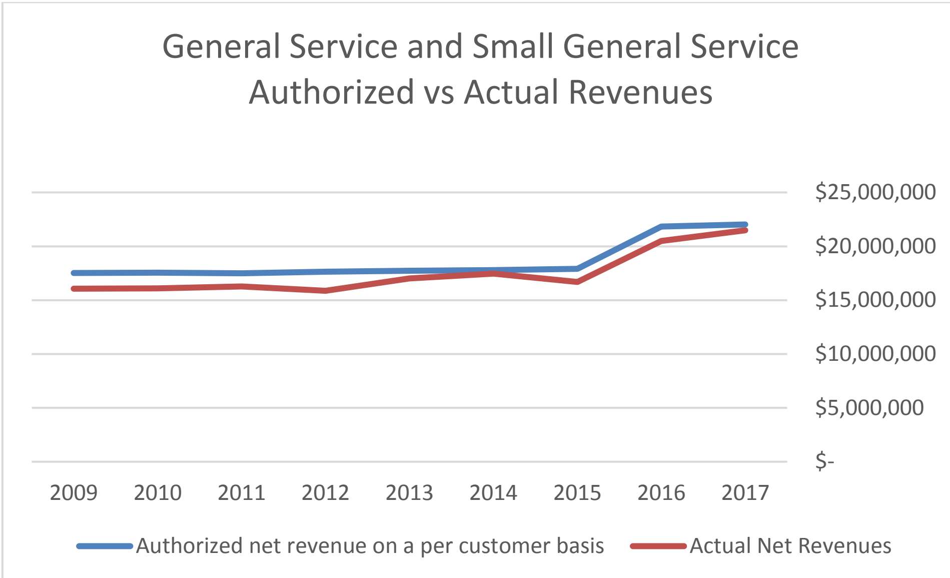
Residential and Farm Classes - 2017 Actual Results Compared to 2016 Test Year

| RDM Adjustments | Source | Unit | Step | 2017 |
|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 2,233,163 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 991,583 |
| Deferral difference | Calculated | | C (A - B) | 1,241,581 |
| Cap on Customer RDM Surcharges | Tab 5 - res & farm RDM | $ | D | 991,583 |
| Forecasted Volumes: April - March | Tab 5 - res & farm RDM | kWh | E | 498,503,774 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001989 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.004480 |
| Total Volumes | Tab 5 - res & farm RDM | kWh | H | 472,030,410 |
| Total Customer Served - month | Tab 5 - res & farm RDM | | I | 608,741 |
| Volume per customer | | kWh | J(H/I) | 775 |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 1.54** |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 3.47** |

**Evaluation of the results for the General Service and Small General Service Classes**

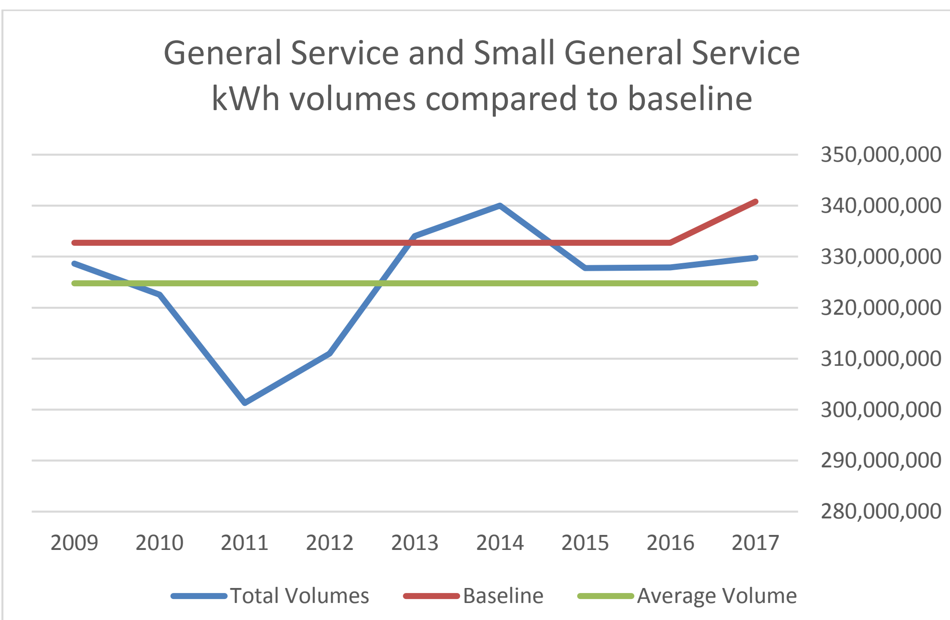
The next step in the evaluation is to look at the decoupling impact on the General Service and Small General Service classes. Looking at the results from 2009 through 2017, it can be observed that actual revenues never exceeded the allowed revenue per customer during that time frame. The graph below shows the comparison for that time period:

**Graph 4:** General Service and Small General Service Revenues 2009 through 2017



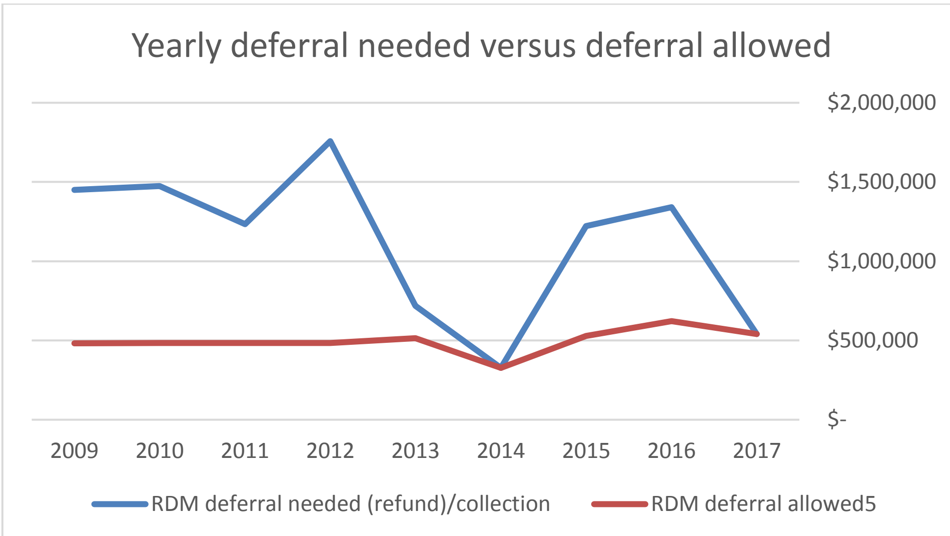

At the same time, inspection of the sale volumes in graph 5 shows that only during the polar vortex winter of 2013 through 2014 did actual volumes exceed the level agreed to in the test year.

**Graph 5:** General Service and Small General Service Volumes 2009 through 2017



Similar to the Residential and Farm classes, we can anticipate there will be a difference in the revenue recovery which needs to be collected in future periods versus what will be allowed per the three percent revenue cap. That difference is shown in graph 6.

**Graph 6**: General Service and Small General Service RDM deferral balance




The evaluation will continue by looking at the 2009 test year and how that compares to 2009 actual results, which is shown in Table 5. Comparison of 2009 actual results against test year billing determinants shows that an under collection of $1,450,465 occurred. The deficiency was primarily related to the rates being too low because 2009 rates were still being impacted by the 2007 rate case. Interim rates from that case were still in effect in January 2009 with final rates from that case commencing in February 2009.

The decoupling impact to the company for the General Service and Small General Service classes in 2009 is material. The customer impact is capped at a revenue adjustment of $482,178 while the sales shortfall and associated revenue was three times greater at $1,450,465, leaving the company deficient $968,287. The final comparison for 2009 is seen in the table below. The customer impact would have been capped at a rate increase of $3.89 per customer. The company, however, needed a rate increase of $11.69 per customer to achieve the revenue requirement for that class.

**Table 5**

General and Small General Service - Comparison of 2009 Test Year to 2009 Actual Results

| **RDM Adjustments** | **Source** | **Unit** | **Step** | **2009** | **2009 Baseline** |
|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | 6 -gen service RDM | $ | A | 1,450,465 | 0 |
| RDM deferral allowed | 6 -gen service RDM | $ | B | 482,176 | 0 |
| Deferral difference | Calculated | | C (A - B) | 968,289 | 0 |
| Cumulative Deferral | Calculated | | Prior balance + Current | 968,289 | |
| Cap on Customer RDM Surcharges | 6 -gen service RDM | $ | D | 482,176 | 515,453 |
| Forecasted Volumes: April -March | 6 -gen service RDM | kWh | E | 327,075,814 | 257,853,263 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001474 | 0 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.004435 | 0 |
| Total Volumes | 6 -gen service RDM | kWh | H | 328,661,035 | 332,724,039 |
| Total Customer Served - month | 6 -gen service RDM | | I | 124,646 | 10,407 |
| Volume per customer | | kWh | J(H/I) | 2,637 | 2,664 |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 3.89** | $ - |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 11.69** | $ - |

Moving to Table 6, a comparison will be made of the 2009 test year rates with the actual 2009 volumes. Here we can see a marginally better result, however, the company is still not falling within the revenue adjustment band width as $333,142 would be deferred until the next collection period. The necessary RDM collection of $829, 295 is one and two-thirds times larger than the allowed revenue cap. Again, before moving on, reflection upon these results confirms that the company was revenue deficient in 2009 and needed to return for a rate case in Minnesota in 2010.

**Table 6**

General and Small General Service - 2009 Test Year Rates Using Actual Volumes

| RDM Adjustments | Source | Unit | Step | 2009 | 2009 Baseline |
|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | 6 -gen service RDM | $ | A | 829,295 | 0 |
| RDM deferral allowed | 6 -gen service RDM | $ | B | 496,152 | 0 |
| Deferral difference | Calculated | | C (A - B) | 333,142 | 0 |
| Cumulative Deferral | Calculated | | Prior balance + Current | 333,142 | |
| Cap on Customer RDM Surcharges | 6 -gen service RDM | $ | D | 496,152 | 520,112 |
| Forecasted Volumes: April -March | 6 -gen service RDM | kWh | E | 327,075,814 | 257,853,263 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001517 | 0 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.002535 | 0 |
| Total Volumes | 6 -gen service RDM | kWh | H | 328,661,035 | 332,724,039 |
| Total Customer Served - month | 6 -gen service RDM | | I | 124,646 | 10,407 |
| Volume per customer | | kWh | J(H/I) | 2,637 | 2,664 |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 4.00** | $ - |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 6.68** | $ - |

Upon implementation of interim rates in 2010 revenue did increase, however, revenues did not exceed the allowed test year amount as the volumes continued to decline from the test year. Again, please bear in mind the interim assumption that Otter Tail used in populating the model. In order to mitigate the impacts of interim rates and subsequent refund, Otter Tail used final rates for the period in which interim rates were in effect. That permits smoothing the revenue stream by removing interim rate impacts. The result is intended to provide a clearer picture of what is happening within the decoupling model.

Falling sales volumes continued to play a role by impacting recovery bandwidth. Looking beyond 2009 through 2015, it is observed that none of the years had an over collection. Even the polar vortex winter of 2013 – 2014 was not enough to drive sales into an over collection. If each year within that period was considered in isolation, the non-compounded, cumulative deferral is $4,878,055.

As described during the evaluation of the residential and farm classes, one point that stands out is the importance of setting the test year sales level correctly. Having sales volumes that are too high corresponds with setting rates too low. The low rates will not allow the utility the opportunity to stay within the bandwidth because there is not enough volume to achieve the revenue requirement target leaving the utility in the position of continually requesting permission to recover the deferred amounts. Even if the 2009 actual volumes were used in conjunction with 2009 test year rates as a starting point to evaluate 2009 through 2017, the cumulative deferral would still have been $4,962,068, which is not a material reduction in the cumulative balance.

This impact can be demonstrated by looking at the comparison of 2015 and 2016 operating results compared against the 2009 test year in table 7.

**Table 7**

General and Small General Service – 2015 And 2016 Actual Results Compared to 2009 Test Year.

| RDM Adjustments | Source | Unit | Step | 2016 | 2015 |
|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 2,115,125 | 1,813,604 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 945,093 | 822,603 |
| Deferral difference | Calculated | | C (A - B) | 1,170,031 | 991,001 |
| | | | | | |
| Cap on Customer RDM Surcharges | Tab 5 - res & farm RDM | $ | D | 945,093 | 822,603 |
| Forecasted Volumes: April - March | Tab 5 - res & farm RDM | kWh | E | 475,098,024 | 483,573,678 |
| | | | | | |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001989 | 0.001701 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.004452 | 0.003750 |
| Total Volumes | Tab 5 - res & farm RDM | kWh | H | 476,120,562 | 486,058,050 |
| Total Customer Served - month | Tab 5 - res & farm RDM | | I | 605,207 | 602,129 |
| Volume per customer | | kWh | J(H/I) | 787 | 807 |
| | | | | | |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 1.56** | **$ 1.37** |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 3.50** | **$ 3.03** |

Table 7 shows that 2015 had a required deferral of $1,813,604 while the deferral cap was $822,603 resulting in a carry forward of $991,001. Looking at 2016 we can see again that there was an under collection as $2,115,125 was needed to reach the allowed revenue per customer, but the deferral was capped at $945,093 resulting in a carry forward of $1,170,031.

Next, we will look at the results for the comparison of 2017 actual results against the 2016 test year. The sales volumes and corresponding rates were sufficient to fall within the recovery bandwidth. The calculated deferral was $541,557 while the deferral cap was $645,001. The impact to the customer is $4.21 per customer and the results are shown in the table below.

**Table 8**

General and Small General Service Classes - 2017 Actual Results Compared to 2016 Test Year

| RDM Adjustments | Source | Unit | Step | 2017 |
|---|---|---|---|---|
| RDM deferral needed (refund)/collection | 6 -gen service RDM | $ | A | 541,557 |
| RDM deferral allowed | 6 -gen service RDM | $ | B | 541,557 |
| Deferral difference | Calculated | | C (A - B) | 0 |
| Cap on Customer RDM Surcharges | 6 -gen service RDM | $ | D | 645,001 |
| Forecasted Volumes: April -March | 6 -gen service RDM | kWh | E | 326,801,503 |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001657 |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.001657 |
| Total Volumes | 6 -gen service RDM | kWh | H | 329,747,999 |
| Total Customer Served - month | 6 -gen service RDM | | I | 129,759 |
| Volume per customer | | kWh | J(H/I) | 2,541 |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 4.21** |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 4.21** |

## IV. LESSONS LEARNED

Now that the results of the model have been calculated, the lessons learned will be applied as a framework to evaluate how effective decoupling can be for Otter Tail Power.

1. Find your reason for adopting decoupling.

At this point Otter Tail is still evaluating potential reasons to implement decoupling. Fresh Energy is the first group to propose this to Otter Tail and the goal of the initiative is to promote distributed energy resources. Stepping back from the issue, perhaps there are other avenues outside of revamping the pricing mechanism that would accomplish the change that Fresh Energy is seeking.

2. Do all the stakeholders want decoupling and understand the impact?

Otter Tail's observance of other Minnesota utilities shows that several consumer advocate groups have opposed decoupling on various grounds, so reaching unanimous support may not be possible. Also, Otter Tail's customers haven't raised the topic either, whether for or against the concept. On the other hand, seeing the magnitude of deferral surcharges that would be applied to customer bills may prove startling for the impacted classes. At this point Otter Tail is not seeing stakeholder consensus on supporting decoupling.

3. Successful decoupling requires the proper starting point in the test year billing determinates.

This point was most illuminating for Otter Tail. Otter Tail looked to the Xcel Energy pilot program for guidance. One must step back and consider the comparative size of the two companies to appreciate the magnitude of what has happened in the growth of the surcharge accounts in both cases using the revenue per customer decoupling model. For comparison, referencing the 2016 form EIA 861 one can see the following:

**Table 9**

Otter Tail Power Residential Sales Compared to Xcel Energy - Minnesota

| Utility Characteristics | | | RESIDENTIAL | | |
|---|---|---|---|---|---|
| | | | Revenues | Sales | Customers |
| Data Year | Utility Name | State | Thousand Dollars | Megawatthours | Count |
| 2016 | Northern States Power Co - Minnesota | MN | 1,136,510.7 | 8,621,046 | 1,131,107 |
| 2016 | Otter Tail Power Co | MN | 53,510.7 | 528,189 | 48,186 |
| | | Percent | 4.71% | 6.13% | 4.26% |

**Table 10**

Otter Tail Power Commercial Sales Compared to Xcel Energy - Minnesota

| Utility Characteristics | | | COMMERCIAL | | |
|---|---|---|---|---|---|
| | | | Revenues | Sales | Customers |
| Data Year | Utility Name | State | Thousand Dollars | Megawatthours | Count |
| 2016 | Northern States Power Co - Minnesota | MN | 1,338,791.8 | 13,491,895 | 137,797 |
| 2016 | Otter Tail Power Co | MN | 90,554.2 | 1,071,890 | 13,286 |
| | | Percent | 6.76% | 7.94% | 9.64% |

For both residential and commercial classes, the Northern States Power – Minnesota part of Xcel is roughly 20 times larger than Otter Tail Power. With that in mind, attention can be focused on the 2017 decoupling report that Xcel filed with the Minnesota Public Utilities Commission in Docket Nos. E002/GR-13-868 and E002/GR-15-826.

**Table 1: Total Over- or Under-Collection of Allowed Revenues by Customer Class**

**2017 Actual Sales and Actual Customer Counts**

| | ($ Millions) | | | Avg Monthly Customer Surcharge/ (Refund) | RDM Rate ($/kWh) Apr 18 – Mar 19 |
|---|---|---|---|---|---|
| | Total RDM Surcharge/ (Refund) | Estimated Surcharge Cap | 2017 Class Impact | | |
| Residential | $25.0 | $26.2 | $25.0 | $1.87[12] | $0.003064 |
| Residential with Space Heating | $1.3 | $0.9 | $0.9 | $2.19[13] | $0.002361 |
| Small Commercial Non-Demand | $1.1 | $2.5 | $1.1 | $1.06[14] | $0.001245 |
| Total | $27.5 | | $27.1 | | |

Now let us turn our attention to Otter Tail's 2017 comparison as shown earlier.

**Table 11**

| RDM Adjustments | Source | Unit | Step | 2017 |
|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 2,456,631 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 1,020,268 |
| Deferral difference | Calculated | | C (A - B) | 1,436,363 |

Otter Tail Power at approximately 1/20th the size of XCEL – Minnesota exceeded the residential surcharge cap by $1,436,363 while XCEL – Minnesota remained with in the residential surcharge cap and only exceeded the Residential with Space Heating category cap by $400,000.

Continuing the comparison, inspection will be made of the General Service/Commercial classes:

**Table 12**

| RDM Adjustments | Source | Unit | Step | 2017 |
|---|---|---|---|---|
| RDM deferral needed (refund)/collection | 6 -gen service RDM | $ | A | 594,796 |
| RDM deferral allowed | 6 -gen service RDM | $ | B | 594,796 |
| Deferral difference | Calculated | | C (A - B) | 0 |

For the nine years of General Service activity reviewed by Otter Tail, only 2017 and 2014 fell within the recovery bandwidth. 2017 of course had the rates set from the 2016 rate case while 2014 had effects of the polar vortex winter.

This comparison illustrated to Otter Tail the importance of setting the initial test year billing determinants for the base line of revenue per customer decoupling.

4. The importance of choosing the correct decoupling mechanism.

Otter Tail does not object to the revenue per customer model that Xcel is using, if the starting test year billing determinants are sufficient to stay within the recovery bandwidth. However, perhaps more thought should be given to the other alternative regulation options shared by Dr. Lowry. After presenting the options, Dr. Lowry prescribed what was in his opinion the best choice for Otter Tail Power, which was the revenue per customer model.

5. After selecting the right model with the proper components, execute implementation.

Otter Tail appreciates the chance to evaluate decoupling examples from both a regional and national perspective. The examination has proved illuminating on the importance of aligning stakeholder interests with the proper measures to achieve those goals.

## V. CONCLUSION

Upon examining the results of the study, Otter Tail notes the impact of several items. First, for the Residential and Farm classes, from 2009 through 2017, Otter Tail would have been applying the maximum surcharge in all years except for 2013 and 2014. In the General Service and Small General Service classes, the maximum surcharge would have been applied in all years except for 2014 and 2017. From the company perspective, questions remain about what would have happened to any unrecovered balance that carried forward in excess of applying the maximum three percent surcharge.

Those observations lead to the impact for the second item, which is the setting the appropriate approved test year billing determinants. The approved volumes from the 2009 test year appear to have been reachable only through the extra-ordinary circumstances of the polar vortex winter[4].

Finally, Otter Tail appreciates having the opportunity to examine the topic and observe how it applies to company operations. This evaluation has proved valuable in examining the topic from both national and local perspectives as well as taking lessons learned from other companies that have implemented decoupling mechanisms.

---

[4] "A polar vortex is a low-pressure system of cold polar air—a normal weather phenomenon. But during the 2013-2014 winter, a high-pressure system in the Pacific pushed the northern polar vortex southward, contributing to North America's cold, snowy and icy winter."
Kazmierczak, Jeanette. "The 2013-2014 polar vortex adds data points to the books." https://climate.nasa.gov/news/2262/the-2013-2014-polar-vortex-adds-data-points-to-the-books/ NASA, April 1, 2015; March 26, 2018.

## Approved Test Year 2009 Operating Revenue Summary Comparison - By Rate Schedule

| Line No. | Rate Schedule | Operating Revenues 2016 | Operating Revenues 2015 | Operating Revenues 2009 | Difference 2009 to 2015 | Percent Change 2009 to 2015 | Difference 2009 to 2016 | Percent Change 2009 to 2016 |
|---|---|---|---|---|---|---|---|---|
| 1 | 9.01 Residential Service (Rate 101) | $ 26,577,802 | $ 22,472,249 | $ 23,472,422 | $ (1,000,173) | -4.26% | $ 3,105,379 | 13.23% |
| 2 | 9.02 Residential Demand Control (Rate 241) | $ 2,293,057 | $ 1,902,251 | $ 2,197,096 | $ (294,845) | -13.42% | $ 95,961 | 4.37% |
| 3 | Total Residential: | $ 28,870,859 | $ 24,374,499 | $ 25,669,518 | $ (1,295,018) | -5.04% | $ 3,201,339 | 12.47% |
| 4 | | | | | | | | |
| 5 | 9.03 Farm Service (Rate 361) | $ 2,281,810 | $ 1,801,410 | $ 1,869,888 | $ (68,478) | -3.66% | $ 411,921 | 22.03% |
| 6 | Total Farm: | $ 2,281,810 | $ 1,801,410 | $ 1,869,888 | $ (68,478) | -3.00% | $ 411,921 | 22.03% |
| 7 | | | | | | | | |
| 8 | **Total Residential and Farm:** | **$ 31,152,669** | **$ 26,175,909** | **$ 27,539,406** | **$ (1,363,496)** | **-4.95%** | **$ 3,613,260** | **13.12%** |
| 9 | | | | | | | | |
| 10 | 10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404) | $ 5,608,261 | $ 4,760,840 | $ 4,546,876 | $ 213,963 | 4.71% | $ 1,061,385 | 23.34% |
| 11 | 10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405) | $ 4,386 | $ 3,829 | $ 2,308 | $ 1,522 | 65.94% | $ 2,078 | 90.07% |
| 12 | 10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408) | $ 31,547 | $ 29,104 | $ 28,675 | $ (839) | -2.93% | $ (0) | 0.00% |
| 13 | 10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401) | $ 12,962,709 | $ 10,809,666 | $ 12,145,208 | $ (1,335,543) | -11.00% | $ 817,501 | 6.73% |
| 14 | 10.02 General Service - 20 kW or Greater - Primary Service (Rate 403) | $ 188,903 | $ 187,951 | $ 267,344 | $ (79,394) | -29.70% | $ (78,441) | -29.34% |
| 15 | 10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710) | $ 1,688,514 | $ 903,939 | $ 562,518 | $ 341,420 | 60.69% | $ 1,125,996 | 200.17% |
| | **Total General Service:** | **$ 20,484,321** | **$ 16,695,328** | **$ 17,552,930** | **$ (858,870)** | **-4.89%** | **$ 2,928,519** | **16.68%** |

**Approved Test Year 2009 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units**

| Line No. | Charge | Units | Billing Units Summer | Billing Units Winter | Billing Units Annual | Approved Rate Summer | Approved Rate Winter | 2016 Operating Revenues Annual | 2015 Operating Revenues Annual | 2009 Approved Operating Revenues Annual | 2009 to 2015 Increase/(Decrease) Annual | 2009 to 2015 Pct Inc/(Dec) Annual | 2009 to 2016 Increase/(Decrease) Annual | 2009 to 2016 Pct Inc/(Dec) Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **9.01 Residential Service (Rate 101)** | | | | | | | | | | | | | |
| 4 | Energy | kWh | 116,187,468 | ######### | 415,946,048 | $0.07976 | $0.08192 | $ 36,734,495 | $ 32,469,088 | $ 33,822,408 | $ (1,353,320) | -4.0% | $ 2,912,087 | 8.6% |
| 9 | **Total Base Revenue:** | | | | | | | $ 36,734,495 | $ 32,469,088 | $ 33,822,408 | $ (1,353,320) | -4.0% | $ 2,912,087 | 8.6% |
| 10 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 11 | Conservation Program Adjustment | | | | | | | $ (674,414) | $ (691,016) | $ (715,427) | $ 24,411 | -3.4% | $ 41,013 | -5.7% |
| 12 | Environmental Cost Recovery Rider Adjustment | | | | | | | | | | | | | |
| 13 | Fuel Adjustment | | | | | | | $ (9,482,279) | $ (9,305,822) | $ (9,634,558) | $ 328,736 | -3.4% | $ 152,279 | -1.6% |
| 14 | Transmission Rider Adjustment | | | | | | | | | | | | | |
| 15 | **Total Adjustments:** | | | | | | | $ (10,156,693) | $ (9,996,839) | $ (10,349,986) | $ 353,147 | -3.4% | $ 193,293 | -1.9% |
| 16 | | | | | | | | | | | | | | |
| 17 | | | | | | | | | | | | | | |
| 18 | **9.02 Residential Demand Control (Rate 241)** | | | | | | | | | | | | | |
| 19 | Customer Charge | | | | | | | | | | | | | |
| 20 | Facilities Charge | | | | | | | | | | | | | |
| 21 | Energy - All kWh | kWh | 10,475,398 | 49,342,908 | 59,818,306 | $0.04671 | $0.05058 | $ 2,855,614 | $ 2,551,720 | $ 2,985,135 | $ (433,415) | -14.5% | $ (129,521) | -4.3% |
| 22 | All kW | kW | 41,951 | 87,155 | 129,106 | $6.08 | $5.11 | $ 648,414 | $ 568,811 | $ 700,420 | $ (131,609) | -18.8% | $ (52,006) | -7.4% |
| 23 | **Total Base Revenue:** | | | | | | | $ 3,504,028 | $ 3,120,532 | $ 3,685,555 | $ (565,023) | -15.3% | $ (181,527) | -4.9% |
| 24 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 25 | Conservation Program Adjustment | | | | | | | $ (80,410) | $ (84,212) | $ (102,887) | $ 18,676 | -18.2% | $ 22,478 | -21.8% |
| 26 | Environmental Cost Recovery Rider Adjustment | | | | | | | | | | | | | |
| 27 | Fuel Adjustment | | | | | | | $ (1,130,562) | $ (1,134,069) | $ (1,385,571) | $ 251,503 | -18.2% | $ 255,009 | -18.4% |
| 28 | Transmission Rider Adjustment | | | | | | | | | | | | | |
| 29 | **Total Adjustments:** | | | | | | | $ (1,210,972) | $ (1,218,281) | $ (1,488,459) | $ 270,178 | -18.2% | $ 277,487 | -18.6% |
| 30 | | | | | | | | | | | | | | |
| 31 | **Total Base Revenue for the COSS Class:** | | | | | | | **$ 40,238,523** | **$ 35,589,620** | **$ 37,507,963** | $ (1,918,343) | -5.1% | $ 2,730,560 | 7.3% |
| 32 | **Total Adjustments for the COSS Class:** | | | | | | | **$ (11,367,665)** | **$ (11,215,120)** | **$ (11,838,444)** | $ 623,325 | -5.3% | $ 470,780 | -4.0% |
| 33 | **Total for the COSS Class:** | | | | | | | **$ 28,870,858** | **$ 24,374,500** | **$ 25,669,519** | $ (1,295,019) | -5.0% | $ 3,201,339 | 12.5% |
| 34 | | | | | | | | | | | | | | |
| 35 | **9.03 Farm Service (Rate 361)** | | | | | | | | | | | | | |
| 37 | Energy - All kWh | kWh | 9,010,104 | 26,061,626 | 35,071,730 | $0.07666 | $0.07873 | $ 3,247,218 | $ 2,680,872 | $ 2,742,578 | $ (61,706) | -2.2% | $ 504,640 | 18.4% |
| 43 | **Total Base Revenue:** | | | | | | | $ 3,247,218 | $ 2,680,872 | $ 2,742,578 | $ (61,706) | -2.2% | $ 504,640 | 18.4% |
| 44 | ***Adjustments for Fuel and CIP included in Base Rates*** | | | | | | | | | | | | | |
| 45 | Conservation Program Adjustment | | | | | | | $ (64,104) | $ (60,792) | $ (60,323) | $ (468) | 0.8% | $ (3,781) | 6.3% |
| 46 | Environmental Cost Recovery Rider Adjustment | | | | | | | | | | | | | |
| 47 | Fuel Adjustment | | | | | | | $ (901,305) | $ (818,671) | $ (812,366) | $ (6,305) | 0.8% | $ (88,938) | 10.9% |
| 48 | Transmission Rider Adjustment | | | | | | | | | | | | | |
| 49 | **Total Adjustments:** | | | | | | | $ (965,408) | $ (879,462) | $ (872,690) | $ (6,772) | 0.8% | $ (92,718) | 10.6% |
| 50 | | | | | | | | | | | | | | |
| 51 | **Total Base Revenue for the COSS Class:** | | | | | | | **$ 43,485,740** | **$ 38,270,492** | **$ 40,250,541** | $ (1,980,049) | -4.9% | $ 3,235,199 | 8.0% |
| 52 | **Total Adjustments for the COSS Class:** | | | | | | | **$ (12,333,072)** | **$ (12,094,581)** | **$ (12,711,134)** | $ 616,553 | -4.9% | $ 378,062 | -3.0% |
| 53 | **Total for the COSS Class:** | | | | | | | **$ 31,152,668** | **$ 26,175,911** | **$ 27,539,407** | $ (1,363,496) | -5.0% | $ 3,613,261 | 13.1% |
| 54 | | | | | | | | | | | | | | |
| 55 | | | | | | | | | | | | | | |

**Approved Test Year 2009 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units**

| Line No. | Charge | Units | Billing Units Summer | Billing Units Winter | Billing Units Annual | Approved Rate Summer | Approved Rate Winter | 2016 Operating Revenues Annual | 2015 Operating Revenues Annual | 2009 Approved Operating Revenues Annual | 2009 to 2015 Increase/(Decrease) Annual | 2009 to 2015 Pct Inc/(Dec) Annual | 2009 to 2016 Increase/(Decrease) Annual | 2009 to 2016 Pct Inc/(Dec) Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 56 | **10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)** | | | | | | | | | | | | | |
| 59 | Energy | kWh | 25,759,423 | 61,896,887 | 87,656,310 | $0.07579 | $0.07784 | $ 8,005,529 | $ 7,057,235 | $ 6,770,227 | $ 287,008 | 4.2% | $ 1,235,302 | 18.2% |
| 64 | **Total Base Revenue:** | | | | | | | $ 8,005,529 | $ 7,057,235 | $ 6,770,227 | $ 287,008 | 4.2% | $ 1,235,302 | 18.2% |
| 65 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 66 | Conservation Program Adjustment | | | | | | | $ (158,797) | $ (158,735) | $ (153,686) | $ (5,049) | 3.3% | $ (5,111) | 3.3% |
| 67 | Environmental Cost Recovery Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 68 | Fuel Adjustment | | | | | | | $ (2,238,470) | $ (2,137,661) | $ (2,069,665) | $ (67,996) | 3.3% | $ (168,805) | 8.2% |
| 69 | Transmission Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 70 | **Total Adjustments:** | | | | | | | $ (2,397,267) | $ (2,296,396) | $ (2,223,351) | $ (73,045) | 3.3% | $ (173,917) | 7.8% |
| 71 | | | | | | | | | | | | | | |
| 72 | **10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)** | | | | | | | | | | | | | |
| 75 | Energy | kWh | 23,421 | 23,491 | 46,912 | $0.07331 | $0.07484 | $ 6,226 | $ 5,766 | $ 3,475 | $ 2,291 | 65.9% | $ 2,751 | 79.2% |
| 76 | **Total Base Revenue:** | | | | | | | $ 6,226 | $ 5,766 | $ 3,475 | $ 2,291 | 65.9% | $ 2,751 | 79.2% |
| 77 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 78 | Conservation Program Adjustment | | | | | | | $ (122) | $ (134) | $ (81) | $ (53) | 65.9% | $ (41) | 51.1% |
| 79 | Environmental Cost Recovery Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 80 | Fuel Adjustment | | | | | | | $ (1,718) | $ (1,803) | $ (1,087) | $ (716) | 65.9% | $ (632) | 58.1% |
| 81 | Transmission Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 82 | **Total Adjustments:** | | | | | | | $ (1,840) | $ (1,937) | $ (1,167) | $ (769) | 65.9% | $ (673) | 57.6% |
| 83 | | | | | | | | | | | | | | |
| 84 | **10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408)** | | | | | | | | | | | | | |
| 87 | Energy | kWh | 274,292 | 274,292 | 548,583 | $0.07715 | $0.07715 | $ 45,831 | $ 42,959 | $ 42,325 | $ 634 | 1.5% | $ 3,506 | 8.3% |
| 88 | **Total Base Revenue:** | | | | | | | $ 45,831 | $ 42,959 | $ 42,325 | $ (634) | | $ 634 | |
| 89 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 90 | Conservation Program Adjustment | | | | - | $ - | $ - | $ (946) | $ (958) | $ (944) | $ (14) | 1.5% | $ (3) | 0.3% |
| 91 | Environmental Cost Recovery Rider Adjustment | | | | | | | | | | | | | |
| 92 | Fuel Adjustment | | | | - | $ - | $ - | $ (13,338) | $ (12,898) | $ (12,707) | $ (191) | 1.5% | $ (631) | 5.0% |
| 93 | Transmission Rider Adjustment | | | | | | | | | | | | | |
| 94 | **Total Adjustments:** | | | | | | | $ (14,285) | $ (13,855) | $ (13,650) | $ (205) | 1.5% | $ (634) | 4.6% |

**Approved Test Year 2009 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units**

| Line No. | Charge | Units | Billing Units Summer | Billing Units Winter | Billing Units Annual | Approved Rate Summer | Approved Rate Winter | 2016 Operating Revenues Annual | 2015 Operating Revenues Annual | 2009 Approved Operating Revenues Annual | 2009 to 2015 Increase/(Decrease) Annual | 2009 to 2015 Pct Inc/(Dec) Annual | 2009 to 2016 Increase/(Decrease) Annual | 2009 to 2016 Pct Inc/(Dec) Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 95 | | | | | | | | | | | | | | |
| 96 | **10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)** | | | | | | | | | | | | | |
| 98 | Energy | kWh | 68,769,863 | ######### | 219,670,926 | $0.06791 | $0.07353 | $ 14,809,389 | $ 13,694,300 | $ 15,766,400 | $ (2,072,100) | -13.1% | $ (957,011) | -6.1% |
| 99 | Demand per kW | kW | 342,444 | 613,736 | 956,180 | $1.22 | $1.02 | $ 2,020,957 | $ 1,087,344 | $ 1,043,401 | $ 43,943 | 4.2% | $ 977,556 | 93.7% |
| 100 | Facilities Charge | | | | 1,335,798 | $0.60 | $0.60 | $ 1,199,343 | $ 837,399 | $ 801,479 | $ 35,920 | 4.5% | $ 397,864 | 49.6% |
| 104 | **Total Base Revenue:** | | | | | | | $ 18,029,689 | $ 15,619,041 | $ 17,611,280 | $ (1,992,239) | -11.3% | $ 418,409 | 2.4% |
| 105 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 106 | Conservation Program Adjustment | | | | | | | $ (335,641) | $ (332,441) | $ (377,834) | $ 45,393 | -12.0% | $ 42,193 | -11.2% |
| 107 | Environmental Cost Recovery Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 108 | Fuel Adjustment | | | | | | | $ (4,731,339) | $ (4,476,934) | $ (5,088,238) | $ 611,303 | -12.0% | $ 356,899 | -7.0% |
| 109 | Transmission Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 110 | **Total Adjustments:** | | | | | | | $ (5,066,980) | $ (4,809,375) | $ (5,466,072) | $ 656,696 | -12.0% | $ 399,092 | -7.3% |
| 111 | | | | | | | | | | | | | | |
| 112 | **10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)** | | | | | | | | | | | | | |
| 114 | Energy | kWh | 776,870 | 2,898,262 | 3,675,132 | $0.06583 | $0.07090 | $ 157,649 | $ 186,549 | $ 256,623 | $ (70,074) | -27.3% | $ (98,974) | -38.6% |
| 115 | Demand per kW | kW | 6,276 | 10,033 | 16,309 | $1.17 | $0.97 | $ 40,954 | $ 14,801 | $ 17,067 | $ (2,266) | -13.3% | $ 23,887 | 140.0% |
| 116 | Facilities Charge | | | | | | $0.00 | $ 16,307 | $ 11,527 | $ 17,447 | $ (5,920) | -33.9% | $ (1,140) | -6.5% |
| 117 | **Total Base Revenue:** | | | | | | | $ 214,910 | $ 212,877 | $ 291,137 | $ (78,260) | -26.9% | $ (76,227) | -26.2% |
| 118 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 119 | Conservation Program Adjustment | | | | | $ - | $ - | $ (1,723) | $ (1,723) | $ (1,645) | $ (78) | 4.8% | $ (78) | 4.7% |
| 120 | Environmental Cost Recovery Rider Adjustment | | | | | $ - | $ - | $ - | $ - | $ - | | | | |
| 121 | Fuel Adjustment | | | | - | $ - | $ - | $ (24,284) | $ (23,203) | $ (22,148) | $ (1,055) | 4.8% | $ (2,136) | 9.6% |
| 122 | Transmission Rider Adjustment | | | | - | $ - | $ - | $ - | $ - | $ - | | | | |
| 123 | **Total Adjustments:** | | | | | | | $ (26,006) | $ (24,926) | $ (23,793) | $ (1,134) | 4.8% | $ (2,214) | 9.3% |
| 124 | | | | | | | | | | | | | | |
| 125 | **10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)** | | | | | | | | | | | | | |
| 127 | Energy - Declared-Peak | kWh | 745 | 311,985 | 312,730 | $0.20332 | $0.21624 | $ 337,954 | $ 26,435 | $ 67,613 | $ (41,178) | -60.9% | $ 270,341 | 399.8% |
| 128 | Energy - Intermediate | kWh | 4,117,970 | 9,134,218 | 13,252,188 | $0.05162 | $0.04703 | $ 1,447,981 | $ 1,195,031 | $ 642,161 | $ 552,870 | 86.1% | $ 805,820 | 125.5% |
| 129 | Energy - Off-Peak | kWh | 2,203,950 | 5,357,308 | 7,561,258 | $0.02331 | $0.03505 | $ 215,389 | $ 177,912 | $ 103,267 | $ 74,645 | 72.3% | $ 112,122 | 108.6% |
| 130 | Demand per kW - Declared-Peak | kW | | | - | N/A | N/A | | | | | | | |
| 131 | Demand per kW - Intermediate | kW | 24,228 | 28,803 | 53,031 | $2.64 | $1.36 | $ 587,115 | $ 436,127 | $ 239,159 | $ 196,968 | 82.4% | $ 347,956 | 145.5% |
| 132 | Demand per kW - Off-Peak | kW | - | - | - | | | | | | | | | |
| 133 | Facilities Charge | kW | | | 102,431 | $0.60 | $0.60 | $ 108,207 | $ 77,158 | $ 61,458 | $ 15,700 | 25.5% | $ 46,749 | 76.1% |
| 134 | Forecasted WAPA Credits | | | | | | | | | | | | | |
| 135 | **Total Base Revenue:** | | | | | | | $ 2,696,645 | $ 1,912,662 | $ 1,113,658 | $ 799,004 | 71.7% | $ 1,582,987 | 142.1% |
| 136 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | | | | |
| 137 | Conservation Program Adjustment | | | | | | | $ (66,779) | $ (69,726) | $ (38,097) | $ (31,630) | 83.0% | $ (28,683) | 75.3% |
| 138 | Environmental Cost Recovery Rider Adjustment | | | | | | | | | | | | | |
| 139 | Fuel Adjustment | | | | | | | $ (941,351) | $ (938,997) | $ (513,043) | $ (425,954) | 83.0% | $ (428,308) | 83.5% |
| 140 | Transmission Rider Adjustment | | | | | | | $ - | $ - | $ - | | | | |
| 141 | **Total Adjustments:** | | | | | | | $ (1,008,131) | $ (1,008,724) | $ (551,140) | $ (457,584) | 83.0% | $ (456,991) | 82.9% |
| 142 | | | | | | | | | | | | | | |
| 143 | **Total Base Revenue for the COSS Class:** | | | | | | | **$ 28,998,829** | **$ 24,850,540** | **$ 25,832,102** | **$ (981,562)** | **-3.8%** | **$ 3,166,727** | **12.3%** |
| 144 | **Total Adjustments for the COSS Class:** | | | | | | | **$ (8,514,509)** | **$ (8,155,213)** | **$ (8,279,172)** | **$ 123,959** | **-1.5%** | **$ (235,337)** | **2.8%** |
| 145 | **Total for the COSS Class:** | | | | | | | **$ 20,484,320** | **$ 16,695,327** | **$ 17,552,930** | **$ (857,603)** | **-4.9%** | **$ 2,931,390** | **16.7%** |
| 146 | | | | | | | | | | | | | | |
| 147 | | | | | | | | | | | | | | |

## Approved Test Year 2016 Operating Revenue Summary Comparison - By Rate Schedule

| Line No. | Rate Schedule | Operating Revenues 2017 | Operating Revenues 2016 | Difference 2016 to 2017 | Percent Change 2016 to 2017 |
|---|---|---|---|---|---|
| 1 | 9.01 Residential Service (Rate 101) | $ 28,928,125 | $ 29,168,294 | $ (240,169) | -0.82% |
| 2 | 9.02 Residential Demand Control (Rate 241) | $ 1,684,750 | $ 3,159,573 | $ (1,474,823) | -46.68% |
| 3 | Total Residential: | $ 30,612,874 | $ 32,327,866 | $ (1,714,992) | -5.30% |
| 4 | | | | | |
| 5 | 9.03 Farm Service (Rate 361) | $ 1,941,548 | $ 2,219,868 | $ (278,320) | -12.54% |
| 6 | Total Farm: | $ 1,941,548 | $ 2,219,868 | $ (278,320) | -12.54% |
| 7 | | | | | |
| 8 | **Total Residential and Farm:** | **$ 32,554,422** | **$ 34,547,734** | **$ (1,993,312)** | -5.77% |
| 9 | | | | | |
| 10 | 10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404) | $ 5,753,087 | $ 5,830,434 | $ (77,346) | -1.33% |
| 11 | 10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405) | $ 5,055 | $ 3,110 | $ 1,946 | 62.58% |
| 12 | 10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408) | $ 32,416 | $ 37,908 | $ 11,949 | 31.52% |
| 13 | 10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401) | $ 13,684,631 | $ 13,934,019 | $ (249,388) | -1.79% |
| 14 | 10.02 General Service - 20 kW or Greater - Primary Service (Rate 403) | $ 217,186 | $ 272,679 | $ (55,492) | -20.35% |
| 15 | 10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710) | $ 1,790,956 | $ 1,650,037 | $ 140,918 | 8.54% |
| | **Total General Service:** | **$ 21,483,332** | **$ 21,728,186** | **$ (227,414)** | -1.05% |

**Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units**

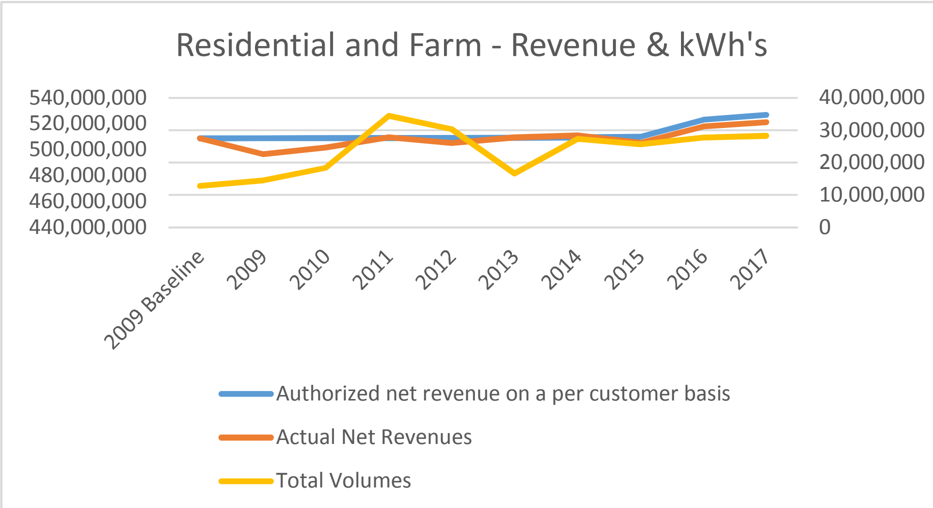
| Line No. | Charge | Units | Billing Units Summer | Billing Units Winter | Billing Units Annual | Approved Rate Summer | Approved Rate Winter | 2017 Actual Operating Revenues Annual | 2016 Approved Operating Revenues Annual | 2017 Actual to 2016 Approved Increase/(Decrease) Annual | 2017 Actual to 2016 Approved Pct Inc/(Dec) Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **9.01 Residential Service (Rate 101)** | | | | | | | | | | |
| 2 | Customer Charge | Bills | | | | | | | | | |
| 3 | Seasonal Fixed Charge | Bills | | | | | | | | | |
| 4 | Energy | kWh | 129,790,104 | 289,433,002 | 419,223,106 | $0.10964 | $0.09064 | $ 37,348,886 | $ 40,464,394 | $ (3,115,509) | -7.7% |
| 5 | Water Heating Control Credit 14.01 (Rate 192) | Bills | | | | | | | | | |
| 6 | Air Conditioning Control Rider 14.08 (Rate 760) | Bills | | | | | | | | | |
| 7 | TailWinds Program 14.09 | kWh | | | | | | | | | |
| 8 | | | | | | | | | | | |
| 9 | **Total Base Revenue:** | | | | | | | $ 37,348,886 | $ 40,464,394 | $ (3,115,508) | -7.7% |
| 10 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 11 | Conservation Program Adjustment | kWh | | | | | | $ (559,191) | $ (937,070) | $ 377,879 | -40.3% |
| 12 | Environmental Cost Recovery Rider Adjustment | $ | | | | | | | | | |
| 13 | Fuel Adjustment | kWh | | | | | | $ (7,861,570) | $ (10,359,031) | $ 2,497,461 | -24.1% |
| 14 | Transmission Rider Adjustment | kWh | | | | | | | | | |
| 15 | **Total Adjustments:** | | | | | | | $ (8,420,761) | $ (11,296,100) | $ 2,875,339 | -25.5% |
| 16 | | | | | | | | | | | |
| 17 | | | | | | | | | | | |
| 18 | **9.02 Residential Demand Control (Rate 241)** | | | | | | | | | | |
| 19 | Customer Charge | Bills | | | | | | | | | |
| 20 | Facilities Charge | Bills | | | | | | | | | |
| 21 | Energy - All kWh | kWh | 10,551,958 | 42,856,627 | 53,408,585 | $0.06425 | $0.06738 | $ 3,265,497 | $ 3,565,643 | $ (300,146) | -8.4% |
| 22 | All kW | kW | 42,281 | 83,281 | 125,562 | $8.00 | $8.00 | $ 854,294 | $ 1,004,496 | $ (150,202) | -15.0% |
| 23 | **Total Base Revenue:** | | | | | | | $ 4,119,791 | $ 4,570,138 | $ (450,347) | -9.9% |
| 24 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 25 | Conservation Program Adjustment | kWh | | | | | | $ (161,702) | $ (117,014) | $ (44,688) | 38.2% |
| 26 | Environmental Cost Recovery Rider Adjustment | $ | | | | | | | | | |
| 27 | Fuel Adjustment | kWh | | | | | | $ (2,273,340) | $ (1,293,552) | $ (979,788) | 75.7% |
| 28 | Transmission Rider Adjustment | kWh | | | | | | | | | |
| 29 | **Total Adjustments:** | | | | | | | $ (2,435,042) | $ (1,410,565) | $ (1,024,476) | 72.6% |
| 30 | | | | | | | | | | | |
| 31 | **Total Base Revenue for the COSS Class:** | | | | | | | **$ 41,468,677** | **$ 45,034,532** | $ (3,565,855) | -7.9% |
| 32 | **Total Adjustments for the COSS Class:** | | | | | | | **$ (10,855,803)** | **$ (12,706,666)** | $ 1,850,863 | -14.6% |
| 33 | **Total for the COSS Class:** | | | | | | | **$ 30,612,874** | **$ 32,327,866** | $ (1,714,992) | -5.3% |
| 34 | | | | | | | | | | | |
| 35 | **9.03 Farm Service (Rate 361)** | | | | | | | | | | |
| 36 | Customer Charge | Bills | | | | | | | | | |
| 37 | Energy - All kWh | kWh | 9,992,135 | 24,704,403 | 34,696,538 | $0.10435 | $0.08535 | $ 3,311,895 | $ 3,151,200 | $ 160,695 | 5.1% |
| 38 | All Three Phase Facilities | Bills | | | | | | | | | |
| 39 | Water Heating Control Credit 14.01 | Bills | | | | | | | | | |
| 40 | Air Conditioning Control Rider 14.08 | Bills | | | | | | | | | |
| 41 | TailWinds Program 14.09 | kWh | | | | | | | | | |
| 42 | | | | | | | | | | | |
| 43 | **Total Base Revenue:** | | | | | | | $ 3,311,895 | $ 3,151,200 | $ 160,695 | 5.1% |
| 44 | ***Adjustments for Fuel and CIP included in Base Rates*** | | | | | | | | | | |
| 45 | Conservation Program Adjustment | kWh | | | | | | $ (91,000) | $ (77,259) | $ (13,741) | 17.8% |
| 46 | Environmental Cost Recovery Rider Adjustment | % | | | | | | | | | |
| 47 | Fuel Adjustment | kWh | | | | | | $ (1,279,348) | $ (854,073) | $ (425,275) | 49.8% |
| 48 | Transmission Rider Adjustment | kWh | | | | | | | | | |
| 49 | **Total Adjustments:** | | | | | | | $ (1,370,347) | $ (931,332) | $ (439,015) | 47.1% |
| 50 | | | | | | | | | | | |
| 51 | **Total Base Revenue for the COSS Class:** | | | | | | | **$ 44,780,572** | **$ 48,185,732** | $ (3,405,160) | -7.1% |
| 52 | **Total Adjustments for the COSS Class:** | | | | | | | **$ (12,226,149)** | **$ (13,637,997)** | $ 1,411,848 | -10.4% |
| 53 | **Total for the COSS Class:** | | | | | | | **$ 32,554,423** | **$ 34,547,735** | $ (1,993,312) | -5.8% |
| 54 | | | | | | | | | | | |
| 55 | | | | | | | | | | | |

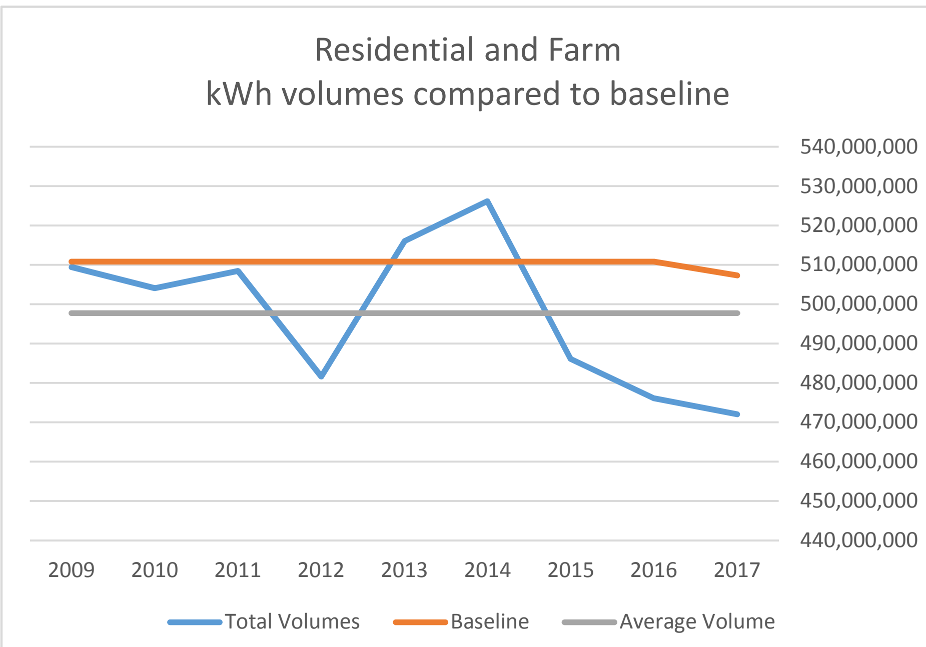
**Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units**

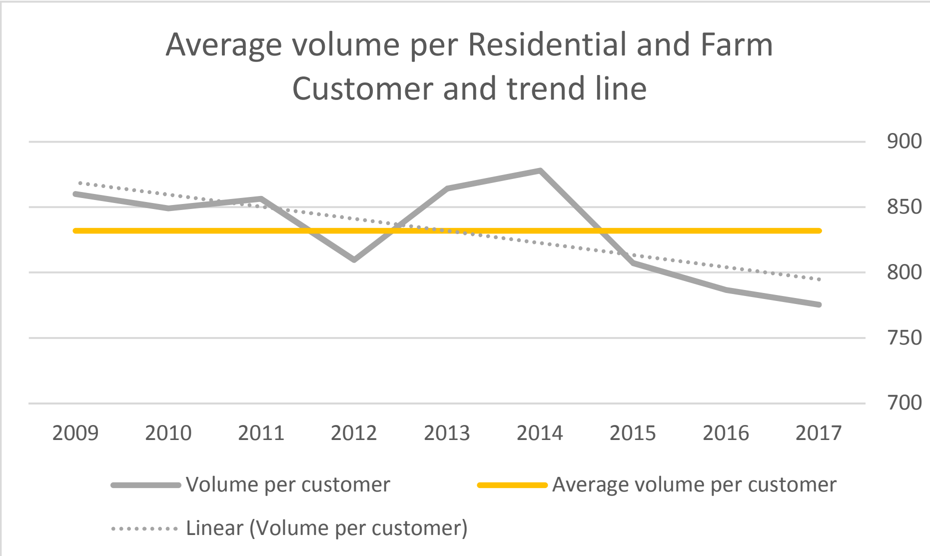
| Line No. | Charge | Units | Billing Units Summer | Billing Units Winter | Billing Units Annual | Approved Rate Summer | Approved Rate Winter | 2017 Actual Operating Revenues Annual | 2016 Approved Operating Revenues Annual | 2017 Actual to 2016 Approved Increase/(Decrease) Annual | 2017 Actual to 2016 Approved Pct Inc/(Dec) Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 56 | **10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)** | | | | | | | | | | |
| 57 | Customer Charge | Bills | | | | | | | | | |
| 58 | Seasonal Fixed Charge | Bills | | | | | | | | | |
| 59 | Energy | kWh | 30,487,603 | 64,904,965 | 95,392,568 | $0.10126 | $0.08226 | $ 8,174,445 | $ 8,426,257 | $ (251,812) | -3.0% |
| 60 | Water Heating Control Credit 14.01 | Bills | | | | | | | | | |
| 61 | Air Conditioning Control Rider 14.08 | Bills | | | | | | $ - | | | |
| 62 | TailWinds Program 14.09 | kWh | | | | | | | | | |
| 63 | | | | | | | | | | | |
| 64 | **Total Base Revenue:** | | | | | | | $ 8,174,445 | $ 8,426,257 | $ (251,812) | -3.0% |
| 65 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 66 | Conservation Program Adjustment | kWh | | | | | | $ (160,438) | $ (215,337) | $ 54,899 | -25.5% |
| 67 | Environmental Cost Recovery Rider Adjustment | % | | | | | | $ - | $ - | | |
| 68 | Fuel Adjustment | kWh | | | | | | $ (2,260,919) | $ (2,380,486) | $ 119,567 | -5.0% |
| 69 | Transmission Rider Adjustment | kWh | | | | | | $ - | $ - | | |
| 70 | **Total Adjustments:** | | | | | | | $ (2,421,358) | $ (2,595,823) | $ 174,466 | -6.7% |
| 71 | | | | | | | | | | | |
| 72 | **10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)** | | | | | | | | | | |
| 73 | Customer Charge | Bills | | | | | | | | | |
| 74 | Seasonal Fixed Charge | Bills | | | | | | | | | |
| 75 | Energy | kWh | 33,541 | 14,253 | 47,794 | $0.09761 | $0.07861 | $ 7,145 | $ 4,394 | $ 2,750 | 62.6% |
| 76 | **Total Base Revenue:** | | | | | | | $ 7,145 | $ 4,394 | $ 2,750 | 62.6% |
| 77 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 78 | Conservation Program Adjustment | kWh | | | | | | $ (138) | $ (107) | $ (32) | 29.9% |
| 79 | Environmental Cost Recovery Rider Adjustment | % | | | | | | $ - | $ - | | |
| 80 | Fuel Adjustment | kWh | | | | | | $ (1,951) | $ (1,178) | $ (773) | 65.6% |
| 81 | Transmission Rider Adjustment | kWh | | | | | | $ - | $ - | | |
| 82 | **Total Adjustments:** | | | | | | | $ (2,089) | $ (1,285) | $ (804) | 62.6% |
| 83 | | | | | | | | | | | |
| 84 | **10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408)** | | | | | | | | | | |
| 85 | Customer Charge | Bills | | | | | $0.00 | | | | |
| 86 | Seasonal Fixed Charge | Bills | | | - | | $0.00 | | | | |
| 87 | Energy | kWh | 321,205 | 321,205 | 642,410 | $0.08589 | $0.08589 | $ 46,457 | $ 55,177 | $ (8,720) | -15.8% |
| 88 | **Total Base Revenue:** | | | | | | | $ 46,457 | $ 55,177 | $ 8,720 | |
| 89 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 90 | Conservation Program Adjustment | kWh | | | - | $ - | $ - | $ (930) | $ (1,433) | $ 502 | -35.1% |
| 91 | Environmental Cost Recovery Rider Adjustment | % | | | | | | | | | |
| 92 | Fuel Adjustment | kWh | | | - | $ - | $ - | $ (13,110) | $ (15,837) | $ 2,726 | -17.2% |
| 93 | Transmission Rider Adjustment | kWh | | | | | | | | | |
| 94 | **Total Adjustments:** | | | | | | | $ (14,041) | $ (17,269) | $ 3,229 | -18.7% |
| 95 | | | | | | | | | | | |
| 96 | **10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)** | | | | | | | | | | |
| 97 | Customer Charge | Bills | | | | | | | | | |
| 98 | Energy | kWh | 65,453,843 | 136,945,561 | 202,399,404 | $0.07495 | $0.07860 | $ 15,288,883 | $ 15,669,687 | $ (380,803) | -2.4% |
| 99 | Demand per kW | kW | 354,779 | 719,710 | 1,074,489 | $3.63 | $1.39 | $ 2,160,415 | $ 2,288,245 | $ (127,830) | -5.6% |
| 100 | Facilities Charge | kW | | | 1,460,814 | $0.97 | $0.97 | $ 1,360,250 | $ 1,416,990 | $ (56,740) | -4.0% |
| 101 | TailWinds Program 14.09 | kWh | | | | | | | | | |
| 102 | Water Heating Control Credit 14.01 | Bills | | | | | | $ - | | | |
| 103 | Air Conditioning Control Rider 14.08 | Bills | | | | | | $ - | | | |
| 104 | **Total Base Revenue:** | | | | | | | $ 18,809,547 | $ 19,374,920 | $ (565,373) | -2.9% |
| 105 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 106 | Conservation Program Adjustment | kWh | | | | | | $ (339,575) | $ (451,351) | $ 111,776 | -24.8% |
| 107 | Environmental Cost Recovery Rider Adjustment | % | | | | | | $ - | $ - | | |
| 108 | Fuel Adjustment | kWh | | | | | | $ (4,785,341) | $ (4,989,550) | $ 204,209 | -4.1% |
| 109 | Transmission Rider Adjustment | kWh | | | | | | $ - | $ - | | |
| 110 | **Total Adjustments:** | | | | | | | $ (5,124,916) | $ (5,440,901) | $ 315,985 | -5.8% |
| 111 | | | | | | | | | | | |
| 112 | **10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)** | | | | | | | | | | |
| 113 | Customer Charge | Bills | | | | | | | | | |
| 114 | Energy | kWh | 1,467,410 | 1,669,419 | 3,136,829 | $0.07244 | $0.07535 | $ 183,385 | $ 232,090 | $ (48,705) | -21.0% |
| 115 | Demand per kW | kW | 7,796 | 9,686 | 17,482 | $4.02 | $1.89 | $ 42,051 | $ 49,646 | $ (7,596) | -15.3% |
| 116 | Facilities Charge | kW | | | | | $0.00 | $ 18,241 | $ 19,827 | $ (1,586) | -8.0% |
| 117 | **Total Base Revenue:** | | | | | | | $ 243,677 | $ 301,563 | $ (57,886) | -19.2% |
| 118 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 119 | Conservation Program Adjustment | kWh | | | | $ - | $ - | $ (1,755) | $ (2,396) | $ 641 | -26.7% |
| 120 | Environmental Cost Recovery Rider Adjustment | % | | | | $ - | $ - | $ - | $ - | | |
| 121 | Fuel Adjustment | kWh | | | - | $ - | $ - | $ (24,735) | $ (26,488) | $ 1,753 | -6.6% |
| 122 | Transmission Rider Adjustment | kWh | | | - | $ - | $ - | $ - | $ - | | |
| 123 | **Total Adjustments:** | | | | | | | $ (26,491) | $ (28,884) | $ 2,394 | -8.3% |
| 124 | | | | | | | | | | | |

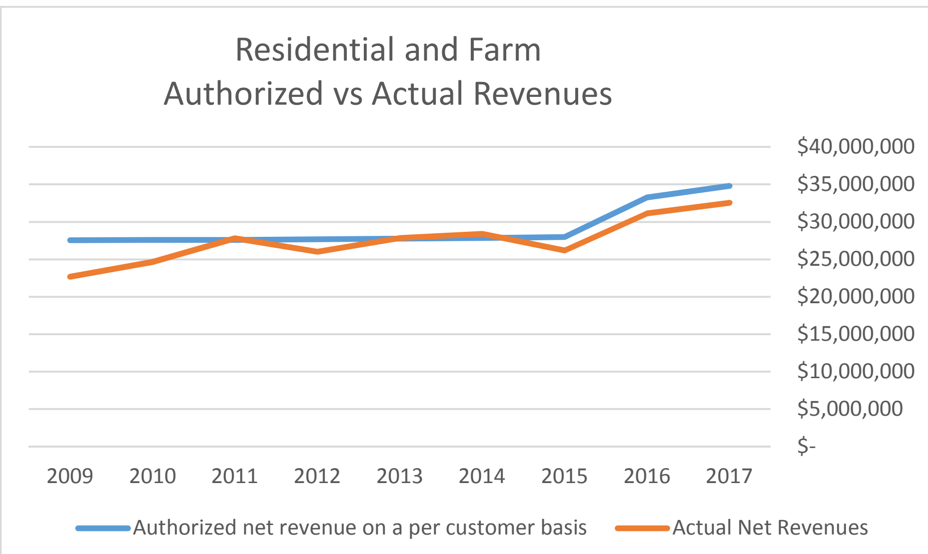
**Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units**

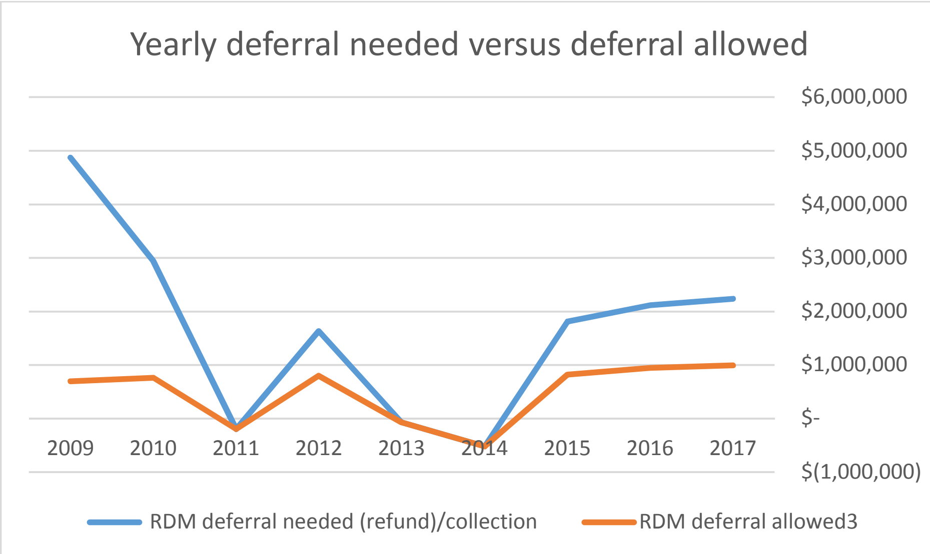
| Line No. | Charge | Units | Billing Units | | | Approved Rate | | 2017 Actual Operating Revenues | 2016 Approved Operating Revenues | 2017 Actual to 2016 Approved Increase/(Decrease) | 2017 Actual to 2016 Approved Pct Inc/(Dec) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Summer | Winter | Annual | Summer | Winter | Annual | Annual | Annual | Annual |
| 125 | **10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)** | | | | | | | | | | |
| 126 | Customer Charge | Bills | | | | | | | | | |
| 127 | Energy - Declared-Peak | kWh | 85,911 | 483,618 | 569,529 | $0.53978 | $0.28109 | $ 249,576 | $ 182,313 | $ 67,263 | 36.9% |
| 128 | Energy - Intermediate | kWh | 6,954,029 | 14,005,566 | 20,959,595 | $0.06938 | $0.06997 | $ 1,532,667 | $ 1,462,440 | $ 70,227 | 4.8% |
| 129 | Energy - Off-Peak | kWh | 6,195,725 | 11,452,196 | 17,647,921 | $0.03910 | $0.04676 | | | | |
| 130 | Demand per kW - Declared-Peak | kW | | | - | N/A | N/A | $ 245,024 | $ 292,039 | | |
| 131 | Demand per kW - Intermediate | kW | 37,413 | 71,430 | 108,843 | $2.67 | $2.69 | $ 619,314 | $ 777,758 | $ (158,444) | -20.4% |
| 132 | Demand per kW - Off-Peak | kW | - | - | - | | | | | | |
| 133 | Facilities Charge | kW | | | 12,994 | $0.97 | $0.97 | $ 115,241 | $ 12,604 | $ 102,637 | 814.3% |
| 134 | Forecasted WAPA Credits | | | | | | | | | | |
| 135 | **Total Base Revenue:** | | | | | | | $ 2,761,822 | $ 2,727,154 | $ 34,668 | 1.3% |
| 136 | ***Adjustments for Riders included in Base Rates*** | | | | | | | | | | |
| 137 | Conservation Program Adjustment | kWh | | | | | | $ (64,329) | $ (89,352) | $ 25,023 | -28.0% |
| 138 | Environmental Cost Recovery Rider Adjustment | % | | | | | | | | | |
| 139 | Fuel Adjustment | kWh | | | | | | $ (906,537) | $ (987,764) | $ 81,228 | -8.2% |
| 140 | Transmission Rider Adjustment | kWh | | | | | | $ - | $ - | | |
| 141 | **Total Adjustments:** | | | | | | | $ (970,866) | $ (1,077,117) | $ 106,251 | -9.9% |
| 142 | | | | | | | | | | | |
| 143 | **Total Base Revenue for the COSS Class:** | | | | | | | **$ 30,043,092** | **$ 30,889,465** | **$ (846,373)** | **-2.7%** |
| 144 | **Total Adjustments for the COSS Class:** | | | | | | | **$ (8,559,760)** | **$ (9,161,279)** | **$ 601,519** | **-6.6%** |
| 145 | **Total for the COSS Class:** | | | | | | | **$ 21,483,332** | **$ 21,728,186** | **$ (244,854)** | **-1.1%** |
| 146 | | | | | | | | | | | |
| 147 | | | | | | | | | | | |

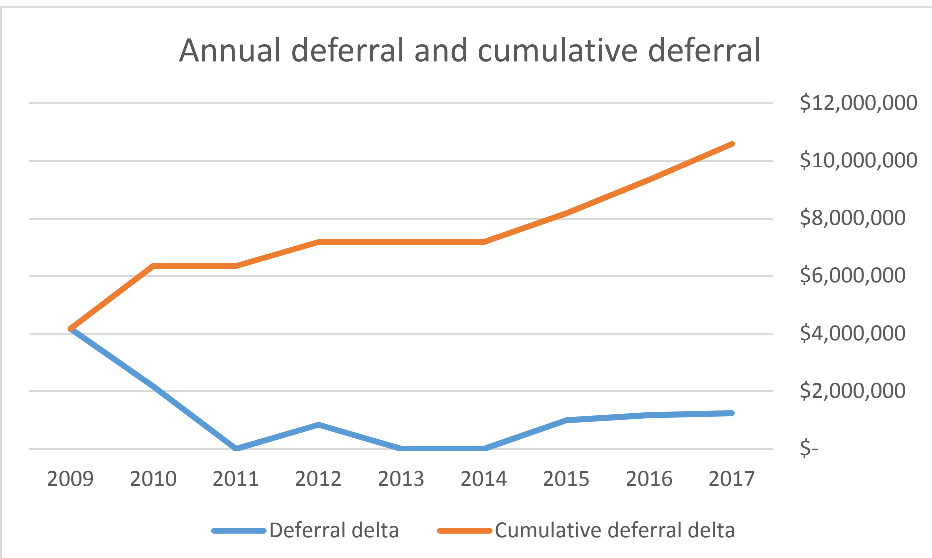

Residential and Farm - Revenue & kWh's
540,000,000
520,000,000
500,000,000
480,000,000
460,000,000
440,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
2009 Baseline
2009
2010
2011
2012
2013
2014
2015
2016
2017
Authorized net revenue on a per customer basis
Actual Net Revenues
Total Volumes

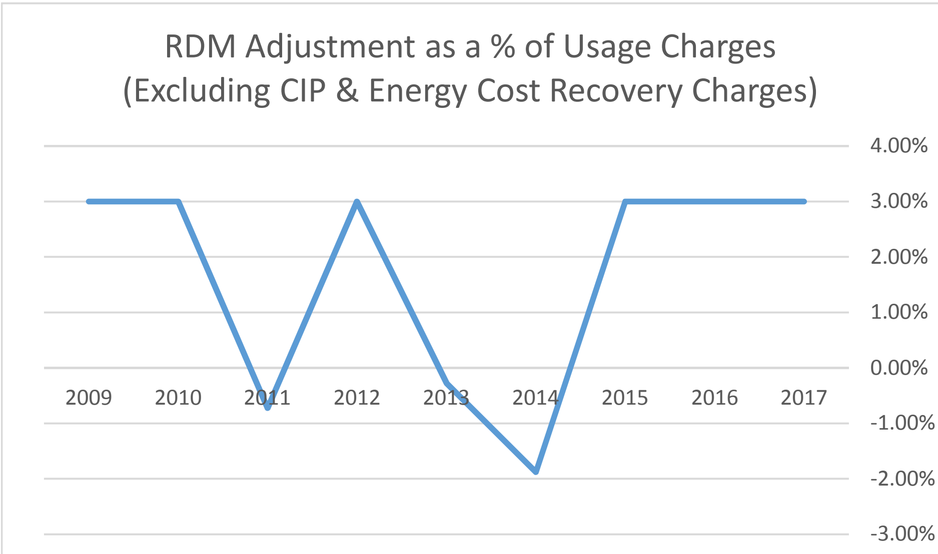

Residential and Farm
kWh volumes compared to baseline
540,000,000
530,000,000
520,000,000
510,000,000
500,000,000
490,000,000
480,000,000
470,000,000
460,000,000
450,000,000
440,000,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
Total Volumes
Baseline
Average Volume

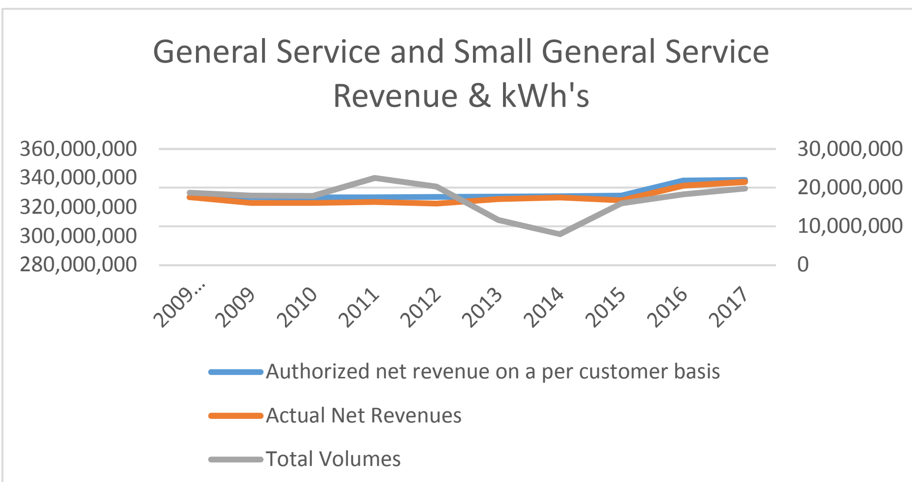

Average volume per Residential and Farm Customer and trend line
900
850
800
750
700
2009 2010 2011 2012 2013 2014 2015 2016 2017
Volume per customer
Average volume per customer
Linear (Volume per customer)

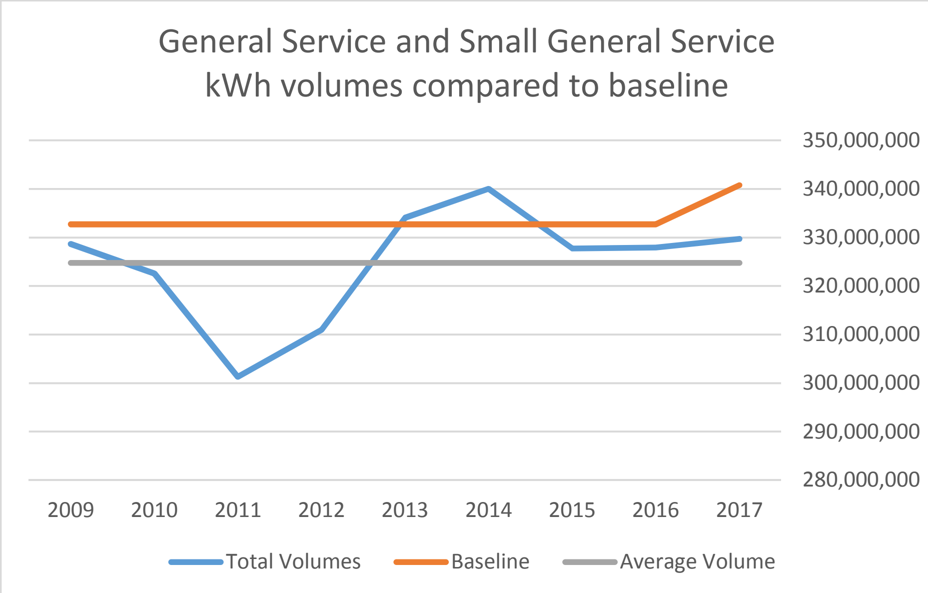

Residential and Farm Authorized vs Actual Revenues
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
2009 2010 2011 2012 2013 2014 2015 2016 2017
Authorized net revenue on a per customer basis
Actual Net Revenues

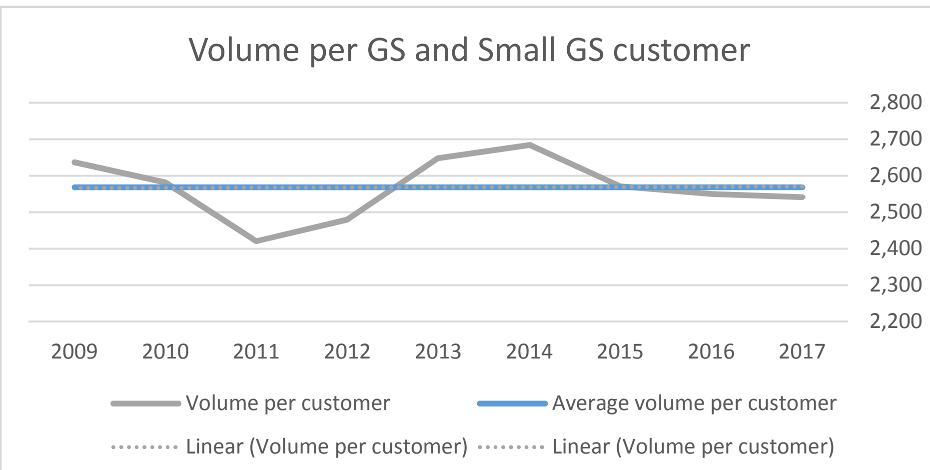

Yearly deferral needed versus deferral allowed
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
$(1,000,000)
2009
2010
2011
2012
2013
2014
2015
2016
2017
RDM deferral needed (refund)/collection
RDM deferral allowed3

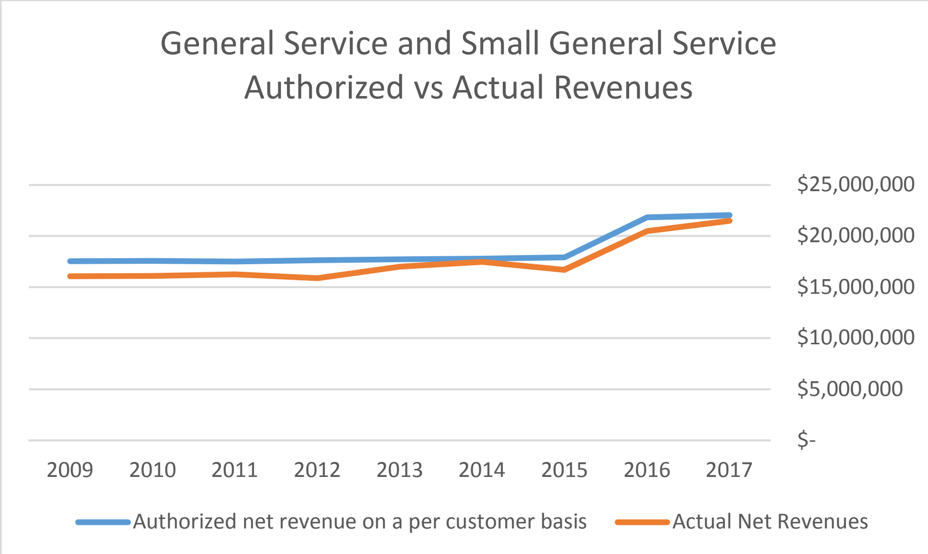

Annual deferral and cumulative deferral
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$-
2009
2010
2011
2012
2013
2014
2015
2016
2017
Deferral delta
Cumulative deferral delta

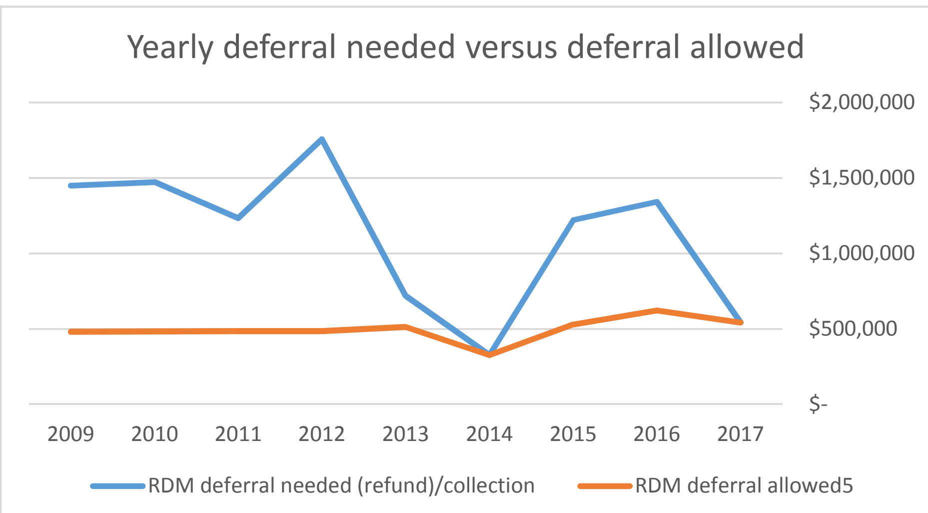

RDM Adjustment as a % of Usage Charges
(Excluding CIP & Energy Cost Recovery Charges)
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
-3.00%
2009
2010
2011
2012
2013
2014
2015
2016
2017

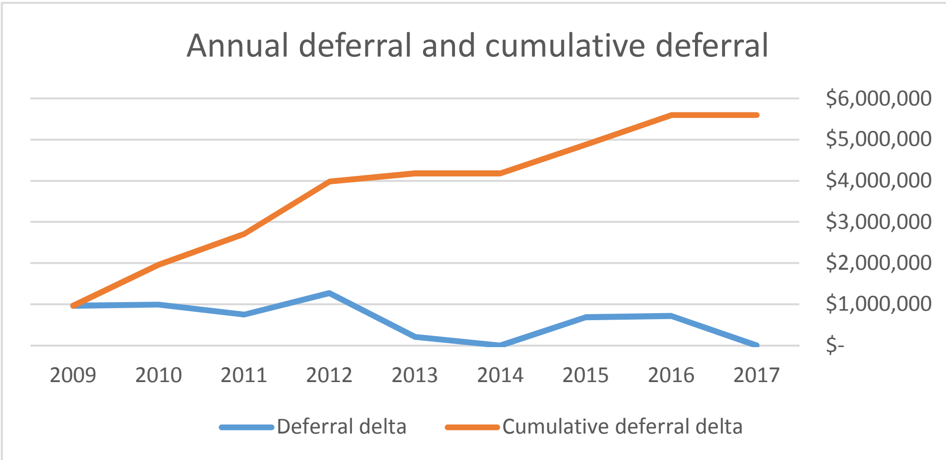

General Service and Small General Service
Revenue & kWh's
360,000,000
340,000,000
320,000,000
300,000,000
280,000,000
30,000,000
20,000,000
10,000,000
0
2009...
2009
2010
2011
2012
2013
2014
2015
2016
2017
Authorized net revenue on a per customer basis
Actual Net Revenues
Total Volumes

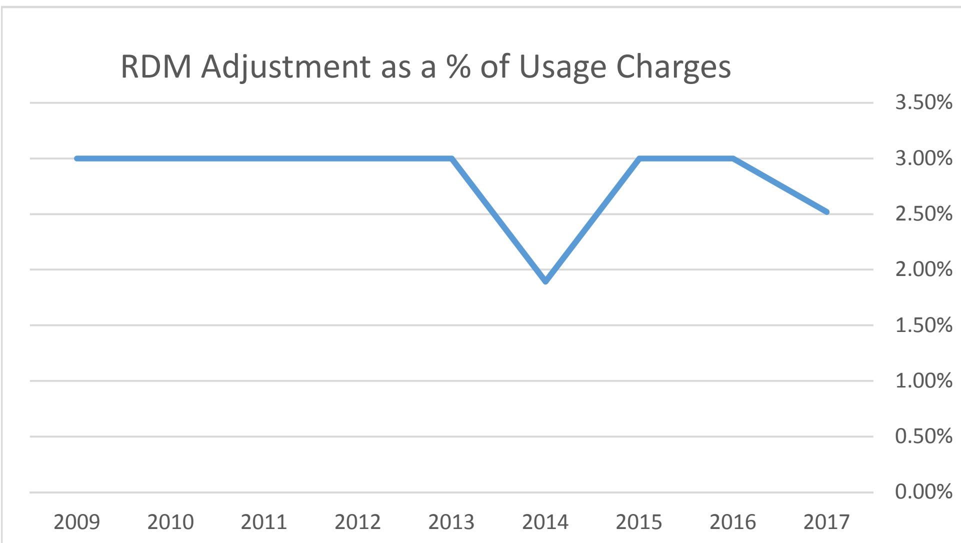

General Service and Small General Service
kWh volumes compared to baseline
350,000,000
340,000,000
330,000,000
320,000,000
310,000,000
300,000,000
290,000,000
280,000,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
Total Volumes
Baseline
Average Volume


Volume per GS and Small GS customer
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2009
2010
2011
2012
2013
2014
2015
2016
2017
Volume per customer
Average volume per customer
Linear (Volume per customer)
Linear (Volume per customer)


General Service and Small General Service
Authorized vs Actual Revenues
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
2009
2010
2011
2012
2013
2014
2015
2016
2017
Authorized net revenue on a per customer basis
Actual Net Revenues


Yearly deferral needed versus deferral allowed
$2,000,000
$1,500,000
$1,000,000
$500,000
$-
2009
2010
2011
2012
2013
2014
2015
2016
2017
RDM deferral needed (refund)/collection
RDM deferral allowed5


Annual deferral and cumulative deferral
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
2009
2010
2011
2012
2013
2014
2015
2016
2017
Deferral delta
Cumulative deferral delta


RDM Adjustment as a % of Usage Charges
3.50%
3.00%
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
2009
2010
2011
2012
2013
2014
2015
2016
2017

| RDM Adjustments | Source | Unit | Step | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Tab 5 - res & farm RDM | $ | A | 2,233,163 | 2,115,125 | 1,813,604 | -522,698 | -76,502 | 1,631,038 | -199,068 | 2,940,028 | 4,869,795 | 0 |
| RDM deferral allowed | Tab 5 - res & farm RDM | $ | B | 991,583 | 945,093 | 822,603 | -522,698 | -76,502 | 794,303 | -199,068 | 763,237 | 694,933 | 0 |
| Deferral difference | Calculated | | C (A - B) | 1,241,581 | 1,170,031 | 991,001 | 0 | 0 | 836,735 | 0 | 2,176,790 | 4,174,862 | |
| | | | | | | | | | | | | | |
| Cap on Customer RDM Surcharges | Tab 5 - res & farm RDM | $ | D | 991,583 | 945,093 | 822,603 | 834,944 | 839,084 | 794,303 | 820,617 | 763,237 | 694,933 | 789,641 |
| Forecasted Volumes : April - March | Tab 5 - res & farm RDM | kWh | E | 498,503,774 | 475,098,024 | 483,573,678 | 516,158,605 | 518,548,825 | 490,229,686 | 501,732,170 | 505,131,870 | 508,085,032 | 0 |
| | | | | | | | | | | | | | |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001989 | 0.001989 | 0.001701 | -0.001013 | -0.000148 | 0.001620 | -0.000397 | 0.001511 | 0.001368 | |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.004480 | 0.004452 | 0.003750 | -0.001013 | -0.000148 | 0.003327 | -0.000397 | 0.005820 | 0.009585 | |
| Total Volumes | Tab 5 - res & farm RDM | kWh | H | 472,030,410 | 476,120,562 | 486,058,050 | 526,192,123 | 516,001,059 | 481,639,228 | 508,429,817 | 504,032,554 | 509,435,858 | 510,836,084 |
| Total Customer Served - month | Tab 5 - res & farm RDM | | I | 608,741 | 605,207 | 602,129 | 599,356 | 597,084 | 594,959 | 593,701 | 593,665 | 592,395 | 49,371 |
| Volume per customer | | kWh | J(H/I) | 775 | 787 | 807 | 878 | 864 | 810 | 856 | 849 | 860 | 862 |
| | | | | | | | | | | | | | |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 1.54** | **$ 1.56** | **$ 1.37** | **$ (0.89)** | **$ (0.13)** | **$ 1.31** | **$ (0.34)** | **$ 1.28** | **$ 1.18** | |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 3.47** | **$ 3.50** | **$ 3.03** | **$ (0.89)** | **$ (0.13)** | **$ 2.69** | **$ (0.34)** | **$ 4.94** | **$ 8.24** | |

| RDM Adjustments | Source | Unit | Step | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | 6 -gen service RDM | $ | A | 541,557 | 1,341,182 | 1,221,199 | 327,161 | 719,043 | 1,757,593 | 1,234,486 | 1,473,642 | 1,450,465 | 0 |
| RDM deferral allowed | 6 -gen service RDM | $ | B | 541,557 | 622,022 | 529,277 | 327,161 | 513,692 | 484,566 | 484,811 | 483,852 | 482,176 | 0 |
| Deferral difference | Calculated | | C (A - B) | 0 | 719,160 | 691,922 | 0 | 205,351 | 1,273,027 | 749,675 | 989,791 | 968,289 | 0 |
| Cumulative Deferral | Calculated | | Prior balance + Current | 5,597,215 | 5,597,215 | 4,878,055 | 4,186,133 | 4,186,133 | 3,980,782 | 2,707,755 | 1,958,079 | 968,289 | |
| | | | | | | | | | | | | | |
| Cap on Customer RDM Surcharges | 6 -gen service RDM | $ | D | 645,001 | 622,022 | 529,277 | 518,354 | 513,692 | 484,566 | 484,811 | 483,852 | 482,176 | 515,453 |
| Forecasted Volumes : April - March | 6 -gen service RDM | kWh | E | 326,801,503 | 328,370,986 | 327,784,760 | 336,945,765 | 335,529,748 | 316,751,822 | 303,720,046 | 317,249,504 | 327,137,570 | 257,853,263 |
| | | | | | | | | | | | | | |
| Allowed Surcharge (Rate) | Calculated | $/kWh | F (B/E) | 0.001657 | 0.001894 | 0.001615 | 0.000971 | 0.001531 | 0.001530 | 0.001596 | 0.001525 | 0.001474 | **0** |
| Required Surcharge (Rate) | Calculated | $/kWh | G (A/E) | 0.001657 | 0.004084 | 0.003726 | 0.000971 | 0.002143 | 0.005549 | 0.004065 | 0.004645 | 0.004434 | **0** |
| Total Volumes | 6 -gen service RDM | kWh | H | 329,747,999 | 327,911,981 | 327,742,353 | 340,013,569 | 334,035,141 | 310,990,716 | 301,296,489 | 322,567,175 | 328,661,035 | 332,724,039 |
| Total Customer Served - month | 6 -gen service RDM | | I | 129,759 | 128,580 | 127,476 | 126,647 | 126,117 | 125,402 | 124,459 | 124,931 | 124,646 | 10,407 |
| Volume per customer | | kWh | J(H/I) | 2,541 | 2,550 | 2,571 | 2,685 | 2,649 | 2,480 | 2,421 | 2,582 | 2,637 | 2,664 |
| | | | | | | | | | | | | | |
| **Per customer at allowed rate** | Calculated | $ | K(F*J) | **$ 4.21** | **$ 4.83** | **$ 4.15** | **$ 2.61** | **$ 4.05** | **$ 3.79** | **$ 3.86** | **$ 3.94** | **$ 3.89** | $ - |
| **Per customer at needed rate** | Calculated | $ | L(G*J) | **$ 4.21** | **$ 10.42** | **$ 9.58** | **$ 2.61** | **$ 5.68** | **$ 13.76** | **$ 9.84** | **$ 11.99** | **$ 11.69** | $ - |

**Residential & Farm: RDM Calculation**

| Usage & Customers | Row Identifier | Unit | 2016 - Rate Case Test Year<br>2016 Test Year | Dr. Lowry 2016 Forecast Example<br>Dr. Lowry Forecast '16 | 2017 Actual<br>2017 | 2016 Actual<br>2016 | 2015 Actual<br>2015 | 2014 Actual<br>2014 | 2013 Actual<br>2013 | 2012 Actual<br>2012 | 2011 Actual<br>2011 | 2010 Actual<br>2010 | 2009 Actual<br>2009 | 2009 - Rate Case Test Year<br>2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service [Rate 101] | [A] | kWh | **419,223,106** | 421,238,209 | 386,580,240 | 391,295,747 | 400,388,013 | 428,076,848 | 422,494,945 | 399,985,327 | 419,068,791 | 413,563,173 | 414,119,324 | **415,946,048** |
| 9.02. Residential Demand Control Service [Rate 241] | [B] | kWh | **53,408,585** | 63,061,602 | 48,918,241 | 48,326,161 | 51,220,923 | 59,506,888 | 57,576,067 | 50,635,839 | 57,009,506 | 55,579,326 | 59,565,714 | **59,818,306** |
| 9.02. Residential Demand Control Service [Rate 241] | [C] | kW | **125,562** | 130,036 | 106,787 | 90,566 | 102,208 | 135,148 | 129,020 | 117,461 | 126,473 | 134,284 | 126,257 | **129,106** |
| 9.03. Farm Service [Rate 361] | [D] | kWh | **34,696,538** | 32,158,807 | 36,531,929 | 36,498,654 | 34,449,114 | 38,608,387 | 35,930,047 | 31,018,062 | 32,351,520 | 34,890,055 | 35,750,820 | **35,071,730** |
| Total Volumes | [E = A+B+D] | kWh | **507,328,229** | 516,458,618 | 472,030,410 | 476,120,562 | 486,058,050 | 526,192,123 | 516,001,059 | 481,639,228 | 508,429,817 | 504,032,554 | 509,435,858 | 510,836,084 |
| Total Demand | [C] | kW | **125,562** | 130,036 | 106,787 | 90,566 | 102,208 | 135,148 | 129,020 | 117,461 | 126,473 | 134,284 | 126,257 | **129,106** |
| Total Customer Served - month | [F] | Customers | **604,829** | 604,407 | 608,741 | 605,207 | 602,129 | 599,356 | 597,084 | 594,959 | 593,701 | 593,665 | 592,395 | **49,371** |

| Rates | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service: Volumetric | [H] | $/kWh | 0.09064 | 1.19260 | 0.09064 | 0.09064 | 0.08192 | 0.08192 | 0.08192 | 0.08192 | 0.08192 | 0.08192 | 0.07162 | Varies by season |
| 9.02. Residential Demand Control Service: Volumetric | [I] | $/kWh | 0.06738 | 0.74716 | 0.06738 | 0.06738 | 0.05058 | 0.05058 | 0.05058 | 0.05058 | 0.05058 | 0.05058 | 0.04263 | Varies by season |
| 9.02. Residential Demand Control Service: Demand | [J] | $/kW | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 5.11000 | 5.11000 | 5.11000 | 5.11000 | 5.11000 | 5.11000 | 3.81000 | Varies by season |
| 9.03. Farm Service: Volumetric | [K] | $/kWh | 0.08535 | 0.09005 | 0.08535 | 0.08535 | 0.07873 | 0.07873 | 0.07873 | 0.07873 | 0.07873 | 0.07873 | 0.06832 | Varies by season |

| Net Revenues Per Actual Billing Determinants | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service: Volumetric | [L = A*H] | $ | **40,464,394** | 42,140,588 | 37,348,886 | 36,734,495 | 32,469,088 | 34,743,904 | 34,278,823 | 32,422,844 | 34,044,731 | 31,616,908 | 30,514,272 | **33,822,408** |
| 9.02. Residential Demand Control Service: Volumetric | [M = B*I] | $ | **3,565,643** | 3,548,758 | 3,265,497 | 2,855,614 | 2,551,720 | 2,970,049 | 2,871,368 | 2,519,865 | 2,840,568 | 2,511,719 | 2,574,649 | **2,985,135** |
| 9.02. Residential Demand Control Service: Demand | [N = C*J] | $ | **1,004,496** | 1,040,290 | 854,294 | 648,414 | 568,811 | 756,506 | 722,020 | 656,209 | 687,275 | 665,795 | 585,915 | **700,420** |
| 9.03. Farm Service: Volumetric | [O = D*K] | $ | **3,151,200** | 3,145,933 | 3,311,895 | 3,247,218 | 2,680,872 | 3,006,091 | 2,798,946 | 2,410,895 | 2,527,608 | 2,556,067 | 2,513,303 | **2,742,578** |
| Calculated Gross Revenues | [P = L+M+N+O] | $ | 48,185,733 | 49,875,568 | 44,780,572 | 43,485,741 | 38,270,492 | 41,476,549 | 40,671,157 | 38,009,813 | 40,100,182 | 37,350,488 | 36,188,139 | **40,250,541** |
| Adjustment for Conservation Improvement Program (CIP) | [Q = E*(-CIP Rate)] | $ | -1,131,342 | -888,309 | -811,892 | -818,927 | -836,020 | -905,050 | -887,522 | -828,419 | -526,610 | -423,387 | -422,793 | **-878,638** |
| Adjustment for Energy Cost Recovery | [R = E*(-ECR Rate)] | $ | -12,506,656 | -12,725,540 | -11,414,258 | -11,514,146 | -11,258,563 | -12,188,188 | -11,952,133 | -11,156,209 | -11,776,760 | -12,271,057 | -13,098,105 | **-11,832,496** |
| Actual Net Revenues | [S = P+Q+R] | $ | 34,547,736 | 36,261,719 | 32,554,422 | 31,152,668 | 26,175,910 | 28,383,311 | 27,831,503 | 26,025,184 | 27,796,812 | 24,656,043 | 22,667,241 | **27,539,407** |
| | | **CIP rate:** | 0.00172 | 0.00172 | 0.00172 | 0.00172 | 0.00172 | 0.00172 | 0.00172 | 0.00172 | 0.00172 | 0.00084 | 0.00084 | 0.00084 |
| | | **ECR rate:** | 0.02464 | 0.02464 | 0.02464 | 0.02464 | 0.02316 | 0.02316 | 0.02316 | 0.02316 | 0.02316 | 0.02316 | 0.02571 | 0.02571 |

| Net Revenues Authorized Per Test Year Determinants | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year Revenue (per table inputs) | [S] | $ | 34,547,736 | 35,765,439 | 34,547,736 | 27,539,407 | 27,539,407 | 27,539,407 | 27,539,407 | 27,539,407 | 27,539,407 | 27,539,407 | 27,539,407 | 27,539,407 |
| Test Year Customers | [T] | Customers | 604,829 | 602,300 | 604,829 | 601,733 | 592,446 | 592,446 | 592,446 | 592,446 | 592,446 | 592,446 | 592,446 | 49,371 |
| Test Year Revenue per Customer | [U = S/T] | $/Customer | 685 | 712 | 685 | 659 | 558 | 558 | 558 | 558 | 558 | 558 | 558 | 558 |
| | | | | | | | | | | | | | | |
| Actual Customers | [V] | | 604,829 | 604,407 | 608,741 | 605,207 | 602,129 | 599,356 | 597,084 | 594,959 | 593,701 | 593,665 | 592,395 | 49,371 |
| Authorized net revenue on a per customer basis | [W = U*V] | $ | 34,547,736 | 35,892,154 | 34,787,586 | 33,267,792 | 27,989,514 | 27,860,613 | 27,755,001 | 27,656,222 | 27,597,744 | 27,596,071 | 27,537,036 | 27,539,407 |

| Actual Net Revenues & RDM Deferral | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual Net Revenues | [S] | $ | 34,547,736 | 36,261,719 | 32,554,422 | 31,152,668 | 26,175,910 | 28,383,311 | 27,831,503 | 26,025,184 | 27,796,812 | 24,656,043 | 22,667,241 | 27,539,407 |
| RDM Deferral [(-) is a refund, (+) is a collection from customer] | [X = W-S] | $ | 0 | -369,565 | 2,233,163 | 2,115,125 | 1,813,604 | -522,698 | -76,502 | 1,631,038 | -199,068 | 2,940,028 | 4,869,795 | 0 |

| RDM Adjustments | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | Y = X | $ | 0 | -369,565 | 2,233,163 | 2,115,125 | 1,813,604 | -522,698 | -76,502 | 1,631,038 | -199,068 | 2,940,028 | 4,869,795 | 0 |
| Projected Volumes:[1] | Z = e | kWh | 0 | 509,610,826 | 498,503,774 | 475,098,024 | 483,573,678 | 516,158,605 | 518,548,825 | 490,229,686 | 501,732,170 | 505,131,870 | 508,085,032 | 0 |
| Forecasted Net Revenues:[2] | BA = n | $ | 0 | 35,833,223 | 33,052,751 | 31,503,106 | 27,420,099 | 27,831,460 | 27,969,455 | 26,476,764 | 27,353,905 | 25,441,236 | 23,164,442 | 26,321,365 |
| Cap on Customer RDM Surcharges | [BB = BA*(0.03)] | $ | 0 | 1,074,997 | 991,583 | 945,093 | 822,603 | 834,944 | 839,084 | 794,303 | 820,617 | 763,237 | 694,933 | 789,641 |
| RDM deferral allowed[3] | [BC = min(Y,BB)] | $ | 0 | -369,565 | 991,583 | 945,093 | 822,603 | -522,698 | -76,502 | 794,303 | -199,068 | 763,237 | 694,933 | 0 |
| RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[4] | [BD = BA/BC] | % | #DIV/0! | -1.03% | 3.00% | 3.00% | 3.00% | -1.88% | -0.27% | 3.00% | -0.73% | 3.00% | 3.00% | 0.00% |
| RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[4] | [BE = BC/(BA+Z*(CIP+ECR))] | % | #DIV/0! | -0.75% | 2.15% | 2.15% | 2.09% | -1.29% | -0.19% | 2.05% | -0.50% | 2.03% | 1.90% | 0.00% |

[1] Projected volumes during the RDM adjustment period [Z] is calculated as a weighted average of 9 months of the current year and 3 months of the subsequent year.

[2] Projected net revenues during the RDM adjustment period [BA] are calculated as a weighted average of 9 months in the current year and 3 months in the subsequent year.

[3] A positive RDM adjustment [BC] is a customer surcharge, a negative adjustment a customer refund.

[4] The RDM adjustment is computed as a percentage of volumetric and demand rates, and applied uniformly to all rates in the service basket.

**General Service: RDM Calculation**

| | | | 2016 - Rate Case Test Year | Dr. Lowry 2016 Forecast Example | 2017 Actual | 2016 Actual | 2015 Actual | 2014 Actual | 2013 Actual | 2012 Actual | 2011 Actual | 2010 Actual | 2009 Actual | 2009 - Rate Case Test Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Usage & Customers** | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
| 10.01. Small General Service (Metered Secondary) [Rate 404] | [A] | kWh | 95,392,568 | 89,918,240 | 92,526,330 | 91,872,171 | 91,795,074 | 93,937,626 | 94,274,382 | 87,563,421 | 81,149,380 | 84,184,168 | 75,886,177 | 87,656,310 |
| 10.01. Small General Service (Metered Primary) [Rate 405] | [B] | kWh | 47,794 | 60,942 | 80,482 | 70,870 | 77,835 | 59,947 | 35,435 | 40,195 | 18,235 | 20,976 | 41,267 | 46,912 |
| 10.01. Small General Service (Non-Metered) [Rate 408] | [C] | kWh | 642,410 | 604,656 | 540,888 | 550,128 | 556,824 | 611,747 | 620,100 | 619,536 | 612,486 | 615,457 | 0 | 548,583 |
| 10.02. General Service (Secondary) [Rate 401] | [D] | kWh | 202,399,404 | 188,526,233 | 197,427,354 | 195,140,249 | 193,279,559 | 200,975,607 | 195,477,673 | 184,585,001 | 194,011,146 | 214,251,471 | 227,216,312 | 219,670,926 |
| **10.02. General Service (Secondary) [Rate 401]** | [E] | kW | 1,074,489 | 999,431 | 1,020,498 | 1,001,556 | 1,001,739 | 1,020,223 | 981,202 | 976,017 | 1,056,676 | 1,109,878 | 1,144,965 | 956,180 |
| 10.02. General Service (Secondary) [Facilities] 401 Facilities Charge | [F] | Annual kW | 1,460,814 | 1,369,790 | 1,402,319 | 1,391,477 | 1,395,664 | 1,422,343 | 1,352,522 | 1,337,369 | 1,416,475 | 1,460,936 | 1,342,000 | 1,335,798 |
| 10.02. General Service (Primary) [Rate 403] | [G] | kWh | 3,136,829 | 1,016,737 | 2,483,823 | 2,148,366 | 2,759,780 | 2,979,180 | 2,848,066 | 3,124,813 | 2,856,298 | 2,869,465 | 4,519,736 | 3,675,132 |
| 10.02. General Service (Primary) [Rate 403] | [H] | kW | 17,482 | 17,712 | 14,109 | 15,175 | 13,929 | 17,257 | 16,722 | 15,049 | 14,609 | 18,152 | 17,045 | 16,309 |
| 10.02. General Service (Primary) [Facilities] 403 Facilities Charge | [I] | Annual kW | 30,503 | 30,382 | 28,063 | 28,299 | 28,816 | 29,653 | 30,786 | 26,041 | 27,888 | 30,915 | 51,611 | 43,618 |
| 10.03. General Service-Time of Use (Declared Peak) [Rate 708] | [J] | kWh | 569,529 | 972,732 | 690,729 | 696,394 | 130,283 | 1,904,004 | 1,104,027 | 455,330 | 102,779 | 249,056 | 310,825 | 312,730 |
| 10.03. General Service-Time of Use (Intermediate) [Rate 709] | [K] | kWh | 20,959,595 | 19,769,966 | 21,971,247 | 22,999,134 | 24,195,612 | 20,566,766 | 21,628,175 | 18,782,762 | 14,134,750 | 13,146,212 | 13,171,499 | 13,252,188 |
| 10.03. General Service-Time of Use (Intermediate) [Rate 709] | [L] | kW | 108,843 | 110,000 | 91,323 | 93,128 | 98,592 | 96,754 | 96,317 | 88,522 | 70,147 | 72,906 | 55,722 | 53,031 |
| 10.03. General Service-Time of Use (Off Peak) [Rate 710] | [M] | kWh | 17,647,921 | 17,092,508 | 14,027,146 | 14,434,669 | 14,947,386 | 18,978,692 | 18,047,283 | 15,819,658 | 8,411,415 | 7,230,370 | 7,515,219 | 7,561,258 |
| 10.03. General Service-Time of Use [Facilities] | [N] | Annual kW | 12,994 | 13,088 | 118,805 | 125,685 | 128,597 | 131,467 | 126,644 | 119,841 | 26,709 | 0 | 0 | 102,431 |
| Total Volumes | [O = A+B+C+D+G+J+K+M] | kWh | 340,796,050 | 317,962,015 | 329,747,999 | 327,911,981 | 327,742,353 | 340,013,569 | 334,035,141 | 310,990,716 | 301,296,489 | 322,567,175 | 328,661,035 | 332,724,039 |
| Total Demand[1] | [P = E+H+L] | kW | 1,200,814 | 1,127,142 | 1,125,931 | 1,109,858 | 1,114,259 | 1,134,234 | 1,094,241 | 1,079,588 | 1,141,432 | 1,200,937 | 1,217,731 | 1,025,520 |
| Total Facilities Demand[2] | [Q = F+I+N] | Annual kW | 1,504,311 | 1,413,259 | 1,549,187 | 1,545,460 | 1,553,077 | 1,583,463 | 1,509,952 | 1,483,251 | 1,471,071 | 1,491,851 | 1,393,611 | 1,481,847 |
| Total Customers | [R] | Customers | 128,057 | 127,263 | 129,759 | 128,580 | 127,476 | 126,647 | 126,117 | 125,402 | 124,459 | 124,931 | 124,646 | 10,407 |

| **Rates** | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.01. Small General Service (Metered Secondary) [Rate 404] | [S] | $/kWh | 0.08226 | 0.08526 | 0.08226 | 0.08226 | 0.07784 | 0.07784 | 0.07784 | 0.07784 | 0.07784 | 0.07784 | 0.07413 | Varies by season |
| 10.01. Small General Service (Metered Primary) [Rate 405] | [T] | $/kWh | 0.07861 | 0.08149 | 0.07861 | 0.07861 | 0.07484 | 0.07484 | 0.07484 | 0.07484 | 0.07484 | 0.07484 | 0.07381 | Varies by season |
| 10.01. Small General Service (Non-Metered) [Rate 408] | [U] | $/kWh | 0.08589 | 0.08843 | 0.08589 | 0.08589 | 0.07715 | 0.07715 | 0.07715 | 0.07715 | 0.07715 | 0.07715 | 0.07490 | Varies by season |
| 10.02. General Service (Secondary) [Rate 401] | [V] | $/kWh | 0.07860 | 0.08167 | 0.07860 | 0.07860 | 0.07353 | 0.07353 | 0.07353 | 0.07353 | 0.07353 | 0.07353 | 0.07107 | Varies by season |
| **10.02. General Service (Secondary) [Rate 401]** | [W] | $/kW | 1.39000 | 1.39000 | 1.39000 | 1.39000 | 1.02000 | 1.02000 | 1.02000 | 1.02000 | 1.02000 | 1.02000 | 0.00000 | Varies by season |
| 10.02. General Service (Secondary) [Facilities] 401 Facilities Charge | [X] | $/Annual kW | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.60000 | 0.60000 | 0.60000 | 0.60000 | 0.60000 | 0.60000 | 0.45766 | Varies by season |
| 10.02. General Service (Primary) [Rate 403] | [Y] | $/kWh | 0.07535 | 0.07829 | 0.07535 | 0.07535 | 0.07090 | 0.07090 | 0.07090 | 0.07090 | 0.06820 | 0.07090 | 0.07075 | Varies by season |
| 10.02. General Service (Primary) [Rate 403] | [Z] | $/kW | 1.89000 | 1.89000 | 1.89000 | 1.89000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.00000 | Varies by season |
| 10.02. General Service (Primary) [Facilities] 403 Facilities Charge | [AA] | $/Annual kW | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.40000 | 0.40000 | 0.40000 | 0.40000 | 0.40000 | 0.40000 | 0.30511 | Varies by season |
| 10.03. General Service-Time of Use (Declared Peak) [Rate 708] | [AB] | $/kWh | 0.28109 | 0.28109 | 0.28109 | 0.28109 | 0.21624 | 0.21624 | 0.21624 | 0.21624 | 0.16779 | 0.21624 | 0.17034 | Varies by season |
| 10.03. General Service-Time of Use (Intermediate) [Rate 709] | [AC] | $/kWh | 0.06997 | 0.07478 | 0.06997 | 0.06997 | 0.04703 | 0.04703 | 0.04703 | 0.04703 | 0.04352 | 0.04703 | 0.04607 | Varies by season |
| 10.03. General Service-Time of Use (Intermediate) [Rate 709] | [AD] | $/kW | 2.67000 | 2.69000 | 2.69000 | 2.69000 | 1.36000 | 1.36000 | 1.36000 | 1.36000 | 1.36000 | 1.36000 | 2.74222 | Varies by season |
| 10.03. General Service-Time of Use (Off Peak) [Rate 710] | [AE] | $/kWh | 0.04676 | 0.04997 | 0.04676 | 0.04676 | 0.03505 | 0.03505 | 0.03505 | 0.03505 | 0.01036 | 0.03505 | 0.01291 | Varies by season |
| 10.03. General Service-Time of Use [Facilities] | [AF] | $/Annual kW | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.60000 | 0.60000 | 0.60000 | 0.60000 | 0.60000 | 0.00000 | 0.00000 | Varies by season |

| **Net Revenues Per Actual Billing Determinants** | | Unit | 2016 Test Year | Dr. Lowry Forecast '16 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2009 Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.01. Small General Service (Metered Secondary): Volumetric [404] | [AG = A*S] | $ | 8,426,257 | 8,206,135 | 8,174,445 | 8,005,529 | 7,057,235 | 7,226,551 | 7,249,924 | 6,730,460 | 6,264,245 | 6,344,103 | 5,943,981 | 6,770,227 |
| 10.01. Small General Service (Metered Primary): Volumetric [405] | [AH = B*T} | $ | 4,394 | 5,555 | 7,145 | 6,226 | 5,766 | 4,417 | 2,603 | 2,952 | 1,345 | 1,543 | 3,264 | 3,475 |
| 10.01. Small General Service (Non-Metered): Volumetric [408] | [AI = C*U] | $ | 55,177 | 53,470 | 46,457 | 45,831 | 42,959 | 47,196 | 47,841 | 47,797 | 47,253 | 46,906 | 0 | 42,325 |
| 10.02. General Service (Secondary): Volumetric [401] | [AJ = D*V] | $ | 15,669,687 | 15,167,884 | 15,288,883 | 14,809,389 | 13,694,300 | 14,249,762 | 13,862,496 | 13,053,357 | 13,909,813 | 15,038,279 | 16,962,091 | 15,766,400 |
| **10.02. General Service (Secondary): Demand [401]** | [AK = E*W] | $ | 2,288,245 | 2,119,389 | 2,160,415 | 2,020,957 | 1,087,344 | 1,107,716 | 1,065,191 | 1,061,498 | 1,148,735 | 738,967 | 0 | 1,043,401 |
| 10.02. General Service (Secondary): Facilities Demand [401 FC] | [AL = F*X] | $ | 1,416,990 | 1,328,696 | 1,360,250 | 1,199,343 | 837,399 | 853,406 | 811,513 | 802,421 | 849,885 | 790,268 | 614,184 | 801,479 |
| 10.02. General Service (Primary): Volumetric [403] | [AM = G*Y] | $ | 232,090 | 78,558 | 183,385 | 157,649 | 186,549 | 202,105 | 193,198 | 210,875 | 196,911 | 196,359 | 328,692 | 256,623 |
| 10.02. General Service (Primary): Demand [403] | [AN = H*Z] | $ | 49,646 | 50,116 | 42,051 | 40,954 | 14,801 | 18,271 | 17,743 | 15,958 | 15,381 | 12,849 | 0 | 17,067 |
| 10.02. General Service (Primary): Facilities Demand [403 FC] | [AO = I*AA] | $ | 19,827 | 19,748 | 18,241 | 16,307 | 11,527 | 11,861 | 12,314 | 10,416 | 11,155 | 11,223 | 15,747 | 17,447 |
| 10.03. General Service-Time of Use (Declared Peak): Volumetric [708] | [AP = J*AB] | $ | 182,313 | 315,686 | 249,576 | 337,954 | 26,435 | 395,406 | 213,877 | 51,987 | 21,469 | 43,675 | 52,960 | 67,613 |
| 10.03. General Service-Time of Use (Intermediate): Volumetric [709] | [AQ = K*AC] | $ | 1,462,440 | 1,473,992 | 1,532,667 | 1,447,981 | 1,195,031 | 1,014,201 | 1,067,776 | 925,945 | 683,409 | 632,338 | 620,919 | 642,161 |
| 10.03. General Service-Time of Use (Intermediate): Demand [709] | [AR = L*AD] | $ | 292,039 | 295,146 | 245,024 | 215,389 | 177,912 | 171,906 | 173,217 | 158,831 | 122,069 | 172,112 | 158,253 | 103,267 |
| 10.03. General Service-Time of Use (Off Peak): Volumetric [710] | [AS = M*AE] | $ | 777,758 | 804,607 | 619,314 | 587,115 | 436,127 | 551,732 | 524,598 | 461,416 | 268,468 | 157,738 | 91,840 | 239,159 |
| 10.03. General Service-Time of Use: Facilities Demand | [AT = N*AF] | $ | 12,604 | 12,695 | 115,241 | 108,207 | 77,158 | 78,880 | 75,986 | 71,904 | 16,025 | 0 | 0 | 61,458 |
| Calculated Gross Revenues | [AU = sum(AG:AT)] | $ | 30,889,466 | 29,931,676 | 30,043,093 | 28,998,830 | 24,850,542 | 25,933,410 | 25,318,276 | 23,605,820 | 23,556,163 | 24,186,358 | 24,791,932 | 25,832,102 |
| Adjustment for Conservation Improvement Program (CIP) | [AV = O*(-CIP Rate)] | $ | -759,975 | -546,895 | -567,167 | -564,009 | -563,717 | -584,823 | -574,540 | -534,904 | -319,225 | -270,956 | -273,416 | -572,285 |
| Adjustment for Energy Cost Recovery | [AW = O*(-ECR rate)] | $ | -8,401,304 | -7,834,584 | -7,992,594 | -7,950,500 | -7,591,496 | -7,875,734 | -7,737,256 | -7,203,478 | -6,978,931 | -7,830,211 | -8,450,204 | -7,706,887 |
| Calculated (Actual) Net Revenues | [AX = AU+AV+AW] | $ | 21,728,187 | 21,550,198 | 21,483,333 | 20,484,321 | 16,695,329 | 17,472,852 | 17,006,480 | 15,867,438 | 16,258,008 | 16,085,190 | 16,068,312 | 17,552,930 |
| | | **CIP rate:** | **0.00172** | **0.00172** | **0.00172** | **0.00172** | **0.00172** | **0.00172** | **0.00172** | **0.00172** | **0.00172** | **0.00084** | **0.00084** | |
| | | **ECR rate:** | **0.02464** | **0.02464** | **0.02464** | **0.02464** | **0.023163** | **0.023163** | **0.023163** | **0.023163** | **0.023163** | **0.023163** | **0.025711** | |

| **Net Revenues Authorized Per Test Year Determinants** | | **Unit** | **2016 Test Year** | **Dr. Lowry Forecast '16** | **2017** | **2016** | **2015** | **2014** | **2013** | **2012** | **2011** | **2010** | **2009** | **2009 Baseline** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year Revenue | [AX] | $ | 21,728,187 | 22,564,068 | 21,728,187 | 21,728,187 | 17,552,930 | 17,552,930 | 17,552,930 | 17,552,930 | 17,552,930 | 17,552,930 | 17,552,930 | 17,552,930 |
| Test Year Customers | [R] | Customers | 128,057 | 127,263 | 128,057 | 128,057 | 124,889 | 124,889 | 124,889 | 124,889 | 124,889 | 124,889 | 124,889 | 10,407 |
| Test Year Revenues per Customer | [AY = AX/R] | $/Customer | 170 | 177.30 | 2,036 | 2,036 | 1,687 | 1,687 | 1,687 | 1,687 | 1,687 | 1,686.58 | 140.55 | 1,687 |
| | | | | | | | | | | | | | | |
| Actual Customers | [AZ] | | 128,057 | 125,516 | 129,759 | 128,580 | 127,476 | 126,647 | 126,117 | 125,402 | 124,459 | 124,931.00 | 124,646 | 10,407 |
| Authorized net revenue on a per customer basis | [BA = AY*AZ] | $ | 21,728,187 | 22,251,013 | 22,024,890 | 21,825,504 | 17,916,528 | 17,800,014 | 17,725,523 | 17,625,031 | 17,492,494 | 17,558,833 | 17,518,777 | 17,552,930 |

| **Actual Net Revenues & RDM Deferral** | | **Unit** | **2016 Test Year** | **Dr. Lowry Forecast '16** | **2017** | **2016** | **2015** | **2014** | **2013** | **2012** | **2011** | **2010** | **2009** | **2009 Baseline** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual Net Revenues | [AX] | $ | 21,728,187 | 21,550,198 | 21,483,333 | 20,484,321 | 16,695,329 | 17,472,852 | 17,006,480 | 15,867,438 | 16,258,008 | 16,085,190 | 16,068,312 | 17,552,930 |
| RDM Deferral [(-) is a refund, (+) is a collection from customer] | [BB = BA-AX] | $ | 0 | 700,816 | 541,557 | 1,341,182 | 1,221,199 | 327,161 | 719,043 | 1,757,593 | 1,234,486 | 1,473,642 | 1,450,465 | 0 |

| **RDM Adjustments** | | **Unit** | **2016 Test Year** | **Dr. Lowry Forecast '16** | **2017** | **2016** | **2015** | **2014** | **2013** | **2012** | **2011** | **2010** | **2009** | **2009 Baseline** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RDM deferral needed (refund)/collection | [BC] | $ | 0 | 700,816 | 541,557 | 1,341,182 | 1,221,199 | 327,161 | 719,043 | 1,757,593 | 1,234,486 | 1,473,642 | 1,450,465 | 0 |
| Projected Volumes :[3] | [BD] | kWh | 0 | 323,670,524 | 326,801,503 | 328,370,986 | 327,784,760 | 336,945,765 | 335,529,748 | 316,751,822 | 303,720,046 | 317,249,504 | 327,137,570 | 257,853,263 |
| Forecasted Net Revenues:[4] | [BE] | $ | 0 | 21,594,695 | 21,500,049 | 20,734,074 | 17,642,577 | 17,278,472 | 17,123,073 | 16,152,198 | 16,160,365 | 16,128,395 | 16,072,531 | 17,181,775 |
| Cap on Customer RDM Surcharges | [BF = BE*(0.03)] | $ | 0 | 647,841 | 645,001 | 622,022 | 529,277 | 518,354 | 513,692 | 484,566 | 484,811 | 483,852 | 482,176 | 515,453 |
| RDM deferral allowed[5] | [BG = min(BC,BF)] | $ | 0 | 647,841 | 541,557 | 622,022 | 529,277 | 327,161 | 513,692 | 484,566 | 484,811 | 483,852 | 482,176 | 0 |
| RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[6] | [BH = BE/BG] | % | 0.00% | 3.00% | 2.52% | 3.00% | 3.00% | 1.89% | 3.00% | 3.00% | 3.00% | 3.00% | 3.00% | 0.00% |
| RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[6] | [BI = BG/(BE+BD*(CIP+ECR))] | % | 0.00% | 2.15% | 1.80% | 2.12% | 2.05% | 1.27% | 2.02% | 2.02% | 2.04% | 2.04% | 1.95% | 0.00% |

[1] Billing demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use).

[2] Facilities charge demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use).

[3] Projected volumes during the RDM adjustment period [BW] are calculated as a weighted average of the current year and subsequent year.

[4] Projected net revenues during the RDM adjustment period [BX] are calculated as a weighted average of the current year and subsequent year.

[5] A positive positive RDM adjustment [BZ] is a customer surcharge, a negative adjustment a customer refund.

[6] The RDM adjustment is computed as a percentage of volumetric, demand and facilities demand rates, and applied uniformly to all rates in the service

Direct Testimony and Schedules
Daniel G. Hansen

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-13-868
Exhibit___(DGH-1)

**Decoupling**

November 4, 2013

## Table of Contents



## Schedules

# I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Daniel G. Hansen. I am a Vice President at Christensen Associates Energy Consulting, LLC located at Suite 400, 800 University Bay Drive, Madison, Wisconsin 53705.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE AS IT RELATES TO DECOUPLING.

A. I have a Ph.D. in Economics from Michigan State University and I have worked as a consultant in the energy industry since 1997. I have conducted independent evaluations of revenue decoupling mechanisms that were implemented at Portland General Electric, New Jersey Natural Gas, South Jersey Gas, and Northwest Natural Gas. I have testified on issues related to revenue decoupling in Arizona, Connecticut, Nevada, Oregon, and Utah. I participated in a panel discussion on revenue decoupling before the Massachusetts Department of Public Utilities. In my work on revenue decoupling, my clients have included a regulator, an environmental organization, a non-profit organization of utility investors, and an investor-owned utility. A summary of my qualifications is provided as Exhibit__(DGH-1) Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony describes and supports the Company's proposed revenue decoupling mechanism. Section II describes the relevance of revenue decoupling for the Company as it pursues its conservation goals. Section III describes the revenue decoupling mechanism and addresses each of the revenue decoupling criteria and standards established in Docket No. E,G-999/CI-08-132. Section IV provides concluding remarks.

## II. THE PURPOSE AND BENEFIT OF REVENUE DECOUPLING

Q. IS THE COMPANY PROPOSING TO IMPLEMENT A MECHANISM THAT CHANGES THE WAY IN WHICH IT RECOVERS REVENUE TOWARD FIXED COSTS?

A. Yes. The Company is proposing to implement a partial revenue decoupling mechanism ("RDM") for its residential customers and a subset of its small commercial and industrial ("C&I") customers (*i.e.*, those that do not pay a demand charge). I refer to the proposal as a partial RDM because it excludes weather effects. The details of the proposed RDM are presented in Section III.

Q. WHAT IS THE PURPOSE OF THE PROPOSED RDM?

A. Because the Company recovers most of its fixed costs through volumetric rates (*i.e.*, energy charges), the Company has a financial incentive to maintain or increase its sales to recover those costs. The proposed RDM is intended to remove the Company's financial disincentive to promote conservation and energy efficiency that exists because of this. By eliminating the link between sales and revenues, the Company's proposed RDM will better align the

Company's shareholder interests with the public policy goals of conservation and energy efficiency.

Q. HOW DO YOU DEFINE "FIXED COSTS" FOR PURPOSES OF THIS DISCUSSION?

A. Fixed costs are those that do not change with the level of customer usage, at least in the short run. For example, the costs associated with a utility's distribution system are fixed because they do not change when customers conserve energy by installing more efficient lighting or purchasing more efficient appliances.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW THE CURRENT RATE STRUCTURES GIVE THE COMPANY A DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY.

A. The recovery of fixed costs through energy charges creates a link between the Company's net revenues and customer sales. When a utility's customers use more energy (*i.e.*, when sales increase), revenues increase. Conversely, when a utility's customers use less energy, there is a decrease in utility revenue toward fixed costs without a corresponding decrease in utility costs. Therefore, a traditional utility ratemaking structure inherently motivates a utility to increase its sales to ensure recovery of its fixed costs and maximize revenues. As such, the traditional ratemaking model creates a disincentive for utilities to fully promote conservation or energy efficiency. The proposed RDM will eliminate this disincentive with respect to the customer classes to which it applies.

Q. HOW DOES THE PROPOSED RDM ADDRESS THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?

A. With the RDM in place, the lost revenue associated with customer usage reductions are placed in a deferral account for recovery in the following year through an increase in the energy rate. Because the utility is "made whole" for the decreased revenues due to conservation, it is indifferent toward customer conservation, absent a consideration of the time cost of money or regulatory uncertainty associated with the utility's ability to recover deferrals.

Q. DOES THE RDM AFFECT THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE?

A. No. With the RDM in place, a customer who is evaluating whether to engage in a conservation activity can expect an immediate benefit that is the same as it would have obtained under standard rates. That is, the customer can expect a bill reduction in the amount of the full volumetric rate, including all riders and fees, multiplied by the amount of saved energy (*i.e.*, kWh). The portion of this bill reduction that is associated with fixed-cost recovery is then placed in the RDM deferral account for the utility to recover in the following year. Because each residential or small C&I customer uses a very small percentage of the total group-level usage, a conserving customer pays back essentially none of its own lost revenues. Therefore, a customer's decision to conserve should not be affected by the presence of the RDM because the customer cannot conserve enough energy to affect the rate it pays in the following year.

Q. HAVE OTHER REGULATORS ACKNOWLEDGED THAT RDMS DO NOT AFFECT THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE?

A. Yes. The Oregon Public Utility Commission concluded the following in Order No. 09-020 for Docket UE-197, which approved an RDM referred to as the Sales Normalization Adjustment, or SNA, for Portland General Electric.

> Staff also argues that the SNA would create a disincentive for customers to improve their energy efficiency because the SNA would increase rates and reduce the bill savings. We believe that the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient. (page 28)

Q. IS THERE A TREND TOWARDS DECOUPLING IN THE GAS AND ELECTRIC UTILITY INDUSTRIES?

A. Yes. Decoupling has become more prevalent in recent years for both gas and electric utilities. One study reports that between May 2009 and May 2013, decoupling increased from 28 to 50 local natural gas distribution utilities and from 12 to 27 electric utilities.[1]

Q. HAVE YOU EXAMINED DECOUPLING MECHANISMS OF OTHER ELECTRIC UTILITIES?

A. Yes. I have found twenty-five electric utilities that currently have an RDM in place, located in twelve states and the District of Columbia. They are listed in Exhibit__(DGH-1), Schedule 2, along with some information about the design of the mechanism.[2] The "RPCD" column indicates whether the RDM uses a revenue per-customer design to determine allowed revenues. Where "no" is indicated, the utility trues up revenues to a pre-specified total revenue amount. For all but one utility, United Illuminating, the revenue amount

---

[1] *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations,* Pamela Morgan, Graceful Systems LLC (Dec. 2012) at pp. 2-3.
[2] The list of decoupled utilities was developed using the previously cited Morgan study and the following study: *State Electric Efficiency Regulatory Frameworks*, Institute for Electric Efficiency, July 2013.

changes over time according to a schedule determined at the time the RDM was approved.

The "Include Weather Effects" column indicates whether the effects of changing weather conditions on customer sales, and therefore utility revenue, are included in the RDM deferrals. The "EE Performance Incentives" column indicates whether the utility has a separate energy efficiency incentive program in place in addition to its RDM. The "Cap on Deferral" column indicates whether the RDM rate adjustments are capped at a certain percentage or level. The "Cap Level" column contains the amount of the cap, if applicable. The "Soft or Hard Cap" column indicates whether deferrals in excess of the cap amount are carried over into subsequent periods, a "soft" cap; or lost forever, a "hard" cap.

Q. IN RECENT YEARS, THE COMPANY HAS PERFORMED WELL RELATIVE TO ITS ENERGY EFFICIENCY TARGETS. GIVEN THAT PERFORMANCE, WHAT IS THE VALUE OF THE PROPOSED RDM?

A. Though the Company has been effective in successfully implementing its DSM programs without a RDM, changing circumstances will make it more important that all regulatory barriers to the utility's promotion of conservation and energy efficiency are removed.

Q. WHAT ARE SOME OF THESE CHANGING CIRCUMSTANCES THAT DRIVE THE NEED FOR A RDM?

A. As the Company indicates in its 2013-2015 Triennial Plan for its Minnesota Electric and Natural Gas Conservation Improvement Program[3] (the

3 Filed June 1, 2012 under Docket No. E,G002 / CIP-12-447

"Triennial Plan"), several challenges have arisen that affect the Company's ability to meet its conservation goals. First, the decline in natural gas prices has reduced the economic benefits associated with pursuing electric conservation, yet the costs to administer these programs have typically increased as the Company has pursued harder-to-reach customers and savings opportunities. The savings opportunities the Company is adding to its portfolio to reach goals can have longer payback periods for customers, making these programs less attractive, which affects participation and overall achievement. In addition, the reduction in avoided costs reduces the cost effectiveness of some programs, putting into question the inclusion of certain measures and programs over the long-term. (Triennial Plan, pps 1-2.)

Second, higher lighting efficiency baselines will make it difficult for the Company to deliver significant and cost-effective energy savings through efficient lighting programs. (Triennial Plan, pg 2.) The 2007 Energy Independence and Security Act increased the minimum efficiency for 45W-100W incandescent light bulbs by 30 percent phased in starting in 2012. As a result, the residential lighting program will no longer deliver the same significant incremental energy savings due to the new baseline/energy standard. In addition, utilities will be further challenged due to the increase in commercial lighting efficiency standards. In a 2009 rulemaking, the Department of Energy increased commercial lighting standards from T12 fluorescent lamps as the baseline to the more efficient T8 lamps. This took effect in 2012.

Third, the Company has been experiencing reductions in residential and small commercial use per customer in recent years, a trend that is expected to continue according to the Company's forecast. In the absence of a decoupling mechanism, this places downward pressure on utility revenues over time. This, coupled with the reality that opportunities for further cost-effective energy efficiency decrease as customers become more efficient, will drive a need for more of the Company's focus on conservation and energy efficiency to stay effective in the market.

While the Company has thus far been willing to promote its DSM programs as effectively as it can in order to meet energy efficiency goals, the financial pressures associated with a less favorable market for energy efficiency due to lower avoided costs, more strict energy efficiency standards, and declining use per customer increase the importance of removing the Company's financial disincentives to promoting conservation and energy efficiency.

Q. WHAT CONSERVATION AND ENERGY EFFICIENCY BENEFITS MAY OCCUR BECAUSE OF THE IMPLEMENTATION OF THE RDM?

A. Most importantly, I expect that the RDM will allow the Company to continue supporting an aggressive energy efficiency portfolio after incorporating consideration for the changing circumstances in the market. As I described earlier, continuing to achieve energy efficiency at the Company's current level will become increasingly challenging in the coming years.

## III. ADDRESSING THE REVENUE DECOUPLING CRITERIA AND STANDARDS

Q. IS THE COMPANY'S DECOUPLING PROPOSAL CONSISTENT WITH THE REVENUE DECOUPLING CRITERIA AND STANDARDS THAT THE MINNESOTA PUBLIC UTILITIES COMMISSION ESTABLISHED FOR PILOT PROGRAMS IN DOCKET NO. E,G-999/CI-08-132?

A. Yes. I will address each of the eight criteria contained in the Standards, which are attached as Exhibit__(DGH-1), Schedule 3.

### *1. Criterion 1*

Q. WHAT IS THE PURPOSE OF THE COMPANY'S RDM AND HOW WILL IT FURTHER THE STATE POLICY OF INCREASED CONSERVATION INVESTMENT?

A. The goal of the RDM is to remove the Company's disincentive to promote conservation and energy efficiency for its residential and non-demand small C&I customers. I discussed the relevance of RDM to the Company's pursuit of its conservation goals in detail in Section II.

### *2. Criterion 2*

Q. PLEASE DESCRIBE THE FORM OF THE PROPOSED REVENUE DECOUPLING MECHANISM, INCLUDING THE TYPES OF SALES CHANGES THAT ARE INCLUDED IN THE MECHANISM.

A. The Company proposes to implement a revenue-per-customer decoupling ("RPCD") mechanism that removes the effect of weather from the decoupling deferrals. The Company's RDM model and proposed tariff are attached as Exhibit__(DGH-1), Schedule 4 and Exhibit__(DGH-1), Schedule 5 respectively. In his direct testimony, Company witness Steven V. Huso provides the class-by-class shares of the overall test year revenue requirement. As explained by Mr. Huso, a portion of the non-fuel revenue requirement is recovered through a fixed "customer charge" while the remaining revenue requirement is recovered through the volumetric energy charge for the residential and small C&I classes. The revenue requirement recovered through the non-fuel energy charge, on a per-customer basis, is the revenue baseline for calculating the decoupling deferrals as described in the formula below. Each month, the RDM deferral will be calculated as the difference between the monthly baseline revenue and the weather-normalized revenue collected under the volumetric rates from those customers.

Specifically, the RPCD mechanism will calculate monthly deferrals as follows:

Equation 1: $Deferral_{c,t} = (FRC_c \text{ x } C_{c,t}) - (FEC_c \text{ x } kWh_{c,t}^{Billed,WN})$

where

$Deferral_{c,t}$ is the RDM deferral for customer group *c* in month *t*;

$FRC_c$ is the fixed revenue per customer for customer group *c*;

$C_{c,t}$ is the number of customers in customer group *c* during month *t*;

$FEC_c$ is the non-fuel energy rate for customer group *c*, expressed in \$/kWh; and

$kWh_{c,t}^{Billed,WN}$ is the weather-normalized billed sales to customer group *c* in month *t*.

The RDM will apply to three customer groups: residential non-space heating,[4] residential space heating,[5] and small C&I customers that do not pay a demand charge.[6] Every twelve months, the cumulative deferral for each customer group will be incorporated into customer rates for the following year by

[4] This includes customers served on rate codes A01, A02, A03, A04, A05, and A06.
[5] This includes customers served on rate codes A00, A01, A02, A03, A04, A05, and A06.
[6] This includes customers served on rate codes A05, A06 1S, A06 3S, A06 P, A09, A10, A11, A12, A16, A18, and A22.

dividing the deferral amount by the forecast of sales to the customer group. A positive cumulative deferral will result in a rate increase. A negative cumulative deferral will result in a rate decrease. Sales changes from all sources except weather will be included in the RDM deferrals.

Q. HAS THIS RDM DESIGN BEEN USED BY OTHER ELECTRIC UTILITIES?

A. Yes. The design matches the RDM used by Idaho Power and Portland General Electric. Similar RPCD mechanisms have been implemented in Maryland, Ohio, Washington, Wisconsin, and the District of Columbia.

Q. HOW WILL THE PARAMETERS IN THE RDM BE CALCULATED?

A. $kWh_{c,t}^{Billed,WN}$ will be calculated as billed sales to customer group $c$ in month $t$, adjusted to account for deviations from normal weather conditions. Sales will be weather normalized using the same methods used to develop test year sales, as described in Section VI and Section X of the testimony of Company witness Jannell E. Marks and in Information Request No. 18 in the October 3, 2013 pre-filing of sales forecast information. $C_{c,t}$ is the number of customers billed in customer group $c$ during month $t$.

$FRC_c$ and $FEC_c$ are calculated for each month of the test year, using test year revenues, numbers of customers, and sales. $FRC_c$ is calculated as the fixed-cost revenue requirement (described below) divided by the number of customers forecast for each month in the 2015 test year[7]. $FEC_c$ is calculated as the fixed-cost revenue requirement (described below) divided by the sales forecast for each month of the 2015 test year. The use of month-specific

7 As described in more detail by Ms. Heuer, the 2015 revenue requirement is calculated using 2014 sales. Present and proposed 2015 revenues are therefore based on the application of present rates and proposed 2015 rates to the 2014 test year budgeted sales and customers supported by Ms. Marks.

values, rather than a single value that is constant across months, for these parameters helps minimize month-to-month deferrals.

Q. DOES THE EXCLUSION OF WEATHER EFFECTS FROM THE RDM RATE ADJUSTMENTS AFFECT THE ABILITY OF THE MECHANISM TO REMOVE THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?

A. No. Because weather conditions are outside of the Company's control, retaining the variability in revenues toward fixed costs that is caused by deviations from normal weather conditions does not change the Company's incentive to promote conservation and energy efficiency. If the Company engages in activities that reduce applicable customer usage levels, the proposed RDM will make the Company whole for the lost revenues associated with the recovery of fixed costs through volumetric rates.

Q. HOW IS THE TOTAL FIXED-REVENUE AMOUNT CALCULATED?

A. It is calculated using the test year energy charges, less the CIP component, multiplied by test year sales for the corresponding customers. Separate values are calculated for each month of the test year. The calculations are conducted at the rate code level, with revenues aggregated up to the customer group level for purposes of the $FRC_c$ and $FEC_c$ calculations. Customer charge revenue is excluded from the RDM because it is already decoupled from customer sales. Schedule 4 contains the calculations of $FRC_c$ and $FEC_c$ using the 2015 test year, as well as a forecast of RDM deferrals for 2015 and 2016.

Q. HAS THE COMPANY PERFORMED ANY SENSITIVITY ANALYSES ON THE RDM CALCULATIONS?

A. Yes, the Company analyzed the impact of changing sales and customer counts on the RDM rates. Exhibit__(DGH-1), Schedule 6 contains the Company's sensitivity analysis using two scenarios: (1) a three percent decrease in sales holding the number of customers constant; and (2) a two percent decrease in the number of customers holding use per customer constant. Note that no RDM deferral is produced in the latter scenario because use per customer has not changed.

*3. Criterion 3*

Q. HOW, IF AT ALL, WILL THE PROPOSED DECOUPLING MECHANISM AFFECT THE COMPANY'S COST OF CAPITAL?

A. Company witness Robert B. Hevert addresses this issue in his direct testimony.

*4. Criterion 4*

Q. WHICH CUSTOMER CLASSES WILL BE INCLUDED IN THE DECOUPLING MECHANISM AND WHY?

A. As described earlier, the RDM will apply to all residential customers and small C&I customers that do not pay a demand charge. The RDM focuses on the customers with the largest share of fixed costs recovered through volumetric rates. Exhibit__(DGH-1), Schedule 7, which contains information provided in the Company's September 19, 2013 compliance filing for Docket No. E002/GR-12-961, shows that for residential and C&I non-demand customers, 85 percent of base revenue is recovered through the energy charge. For the customers not eligible for the RDM, which consist largely of C&I customers who pay demand charges, 52 percent of base revenue is recovered through the energy charge. Note that, for these customers, we have included revenue from demand charges as non-volumetric revenue.

The Company has excluded larger C&I customers from the RDM because the sales of this customer group tend to be more volatile and the class revenue per customer is more sensitive to a single large customer leaving the system. Also, revenue decoupling will be a new regulatory structure for the Company and limiting its application is a more conservative approach of implementing the mechanism.

*5. Criterion 5A*

Q. HOW WILL DECOUPLING ADJUSTMENTS BE CALCULATED?

A. Separate adjustments will be calculated for the residential non-space heating, residential space heating, and small C&I non-demand customer groups. For each group, the monthly deferral amounts will be calculated according to Equation 1 above. The Company does not propose to apply a carrying charge on deferrals. At the end of a 12-month period, the total deferral for each customer group will be divided by the forecast of sales to that group for the coming year. The resulting charge will be added to or subtracted from the customer group's volumetric rate for the following 12 months. The forecast of sales will be developed using the methods described in the testimony of Ms. Marks.

*6. Criterion 5B*

Q. WHEN WILL DECOUPLING-INDUCED RATE ADJUSTMENTS BE MADE?

A. RDM rate adjustments will be made once per year and remain in effect for 12 months. The Company proposes to begin calculating deferrals in the month after the Commission's final Order in this proceeding. The RDM deferrals will be calculated each month through December, after which the RDM rate adjustment will be calculated and put into effect on April 1 for the following 12 months. The RDM rate adjustment will include deferrals for January through December. However, the first year of the RDM adjustment may include less than 12 monthly deferrals due to implementation timing.

*7. Criterion 5C*

Q. WILL THE DECOUPLING-INDUCED RATE ADJUSTMENTS BE SUBJECT TO A CAP OR COLLAR ?

A. If the rate adjustment produces a rate increase that is more than five percent of total customer group revenue, including fuel and all applicable riders, the excess deferral amount above the five percent will be carried over to the RDM deferral account in the following year. There will be no limit on the rate reduction that the RDM rate adjustment produces.

Q. IS IT COMMON FOR DEFERRALS IN EXCESS OF THE CAP TO BE CARRIED OVER INTO SUBSEQUENT YEARS?

A. Yes. As my survey of electric RDMs shows in Exhibit__(DGH-1), Schedule 2, 10 out of the 12 utilities with caps on deferrals allow the excess to be carried over into the subsequent year. The RDMs in place at the remaining 13 utilities do not place a cap on the RDM rate adjustment.

*8. Criterion 5D*

Q. WHICH PORTION OF THE CUSTOMER'S BILL WILL BE AFFECTED BY THE DECOUPLING-INDUCED RATE ADJUSTMENTS?

A. The decoupling deferrals will affect the energy charge in the following year. The deferral could cause the energy charge to increase or decrease.

*9. Criterion 5E*

Q. HOW WILL THE DECOUPLING-INDUCED RATE ADJUSTMENT BE DISPLAYED ON THE CUSTOMER'S BILL?

A. The RDM rate adjustment will be listed as a separate line item on the customer's bill.

*10. Criterion 5F*

Q. HOW LONG WILL THE DECOUPLING MECHANISM BE IN PLACE?

A. The Company is proposing to implement the decoupling mechanism as an ongoing program. According to the Order, the mechanism is not eligible for pilot program status, as all pilot proposals needed to be filed by December 30, 2011.

*11. Criterion 5G*

Q. HOW WILL THE DECOUPLING MECHANISM WORK IN CONCERT WITH THE COMPANY'S AUTOMATIC RECOVERY MECHANISMS AND FINANCIAL INCENTIVES?

A. The Company's proposed RDM is compatible with all of its automatic recovery mechanisms and financial incentives. The RDM only includes revenue from base energy charges, excluding the Conservation Cost Recovery Charge (CCRC) component. Therefore, the RDM does not affect the way in which the Company's current riders function. In addition, the RDM is compatible with the Company's existing shared savings demand-side management ("DSM") financial incentive model. That is, the RDM has the effect of minimizing any disincentive to promote conservation and energy efficiency that is caused by the recovery of fixed costs through volumetric rates. Notably, the RDM does not provide the utility with an *incentive* to promote conservation or energy efficiency. Rather, the RDM renders the utility indifferent to the usage levels of the applicable customers. It is therefore appropriate and compatible to provide the utility with a separate incentive to promote conservation and energy efficiency through mechanisms such as the DSM financial incentive model.

Q. ARE THERE ANY OTHER ELECTRIC UTILITIES THAT HAVE BOTH A RDM AND AN ENERGY EFFICIENCY INCENTIVE MECHANISM?

A. Yes. As shown in Exhibit__(DGH-1), Schedule 2, many decoupled electric utilities also have incentives associated with meeting or exceeding energy efficiency goals, including utilities in California, Connecticut, Massachusetts, New York, Ohio, and Rhode Island.

*12. Criterion 6*

Q. DOES THE COMPANY'S DECOUPLING PROPOSAL RAISE ANY CONCERNS REGARDING SERVICE QUALITY?

A. No. The Company is already subject to under-performance penalties across a range of service quality measures, including customer complaints, telephone response time, System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and invoicing accuracy. The service quality performance goals and penalties are described in

Section 1.9 of the General Rules and Regulations within Xcel Energy's Minnesota Electric Rate Book.

Even in the absence of the existing penalties, the proposed RDM would not introduce a disincentive for the Company to continue providing high quality customer service. A RDM would only serve as a disincentive if customers were likely to use less electricity in response to receiving poor customer service from the utility, for which the utility would subsequently be "made whole" through the RDM. It is unlikely that customers would respond in that manner to service quality problems.

With respect to service outages, the RDM has only a minor effect on utility revenue. Specifically, the lost sales caused by the service outage reduce utility revenues, but under the RDM those lost revenues, which are limited to the fixed-cost recovery component, would be recovered for the utility through the RDM rate adjustment. However, the effect on the RDM deferral from delaying a response to service outages would be trivial compared to the existing SAIDI- and SAIFI-based penalties and the liability to which utility may be exposed.

*13. Criterion 7*

Q. HOW DOES THE COMPANY PROPOSE TO EVALUATE THE DECOUPLING MECHANISM OVER TIME?

A. The Company will provide an annual report based on the items that were required for pilot programs related to the performance of the RDM. The Company proposes to include the following items in an annual report: (1) total over or under collection of allowed revenues by class; (2) total collection of prior deferred revenue; (3) calculations of the RDM deferral amounts; (4) the number of customer complaints; (5) the amount of revenues stabilized and how the stabilization impacted the Company's overall risk profile; and (6) a comparison of how revenues under traditional regulation would have differed from those collected under the decoupling proposal. The Company proposes to continue reporting the details of our conservation program results, including how the RDM influenced the achievement of those goals, in our annual status reports in Docket No. E,G002/CIP-09-198.

*14. Criterion 8*

Q. THE FINAL CRITERION INCLUDED IN THE ORDER RELATES TO PILOT PROGRAM IMPLEMENTATION. EVEN THOUGH THE COMPANY IS PROPOSING AN ONGOING PROGRAM AND NOT A PILOT PROGRAM, ARE THERE ANY RELEVANT ISSUES TO CONSIDER?

A. Yes. As prescribed, the decoupling mechanism is being implemented as part of a rate case. In addition, more than one customer class is included in the decoupling proposal.

## IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission adopt the Company's proposal to implement a revenue decoupling mechanism for its residential and small C&I customers that do not pay a demand charge. The mechanism will help ensure that the Company continues to perform well in its promotion of energy efficiency. The design of the mechanism has been implemented, and subsequently renewed, in other electric jurisdictions and the proposal meets all of the requirements contained in the Revenue Decoupling Criteria and Standards the Commission established in Docket No. E,G-999/CI-08-132.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

# Daniel G. Hansen

RESUME

September 2013

## Address:

800 University Bay Drive, Suite 400
Madison, WI 53705–2299
Telephone: 608.231.2266
Fax: 608.231.2108
Email: dghansen@caenergy.com

## Academic Background:

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

## Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

## Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

**Major Projects:**

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

**Professional Papers:**

"An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123," with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," with Michael O'Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

**Testimony and Reports before Regulatory Agencies:**

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding a the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

| **Utility** | **State** | **RPCD?** | **Include Weather Effects?** | **EE Performance Incentives?** | **Cap on Deferral** | **Cap Level** | **Soft or Hard Cap?** |
|---|---|---|---|---|---|---|---|
| PG&E | California | No | Yes | Yes | No | n/a | n/a |
| SCE | California | No | Yes | Yes | No | n/a | n/a |
| SDG&E | California | No | Yes | Yes | No | n/a | n/a |
| United Illuminating | Connecticut | No | Yes | Yes | No | n/a | n/a |
| PEPCO | District of Columbia | Yes | Yes | No | Yes | 10% of base rate | Soft |
| Hawaii Electric | Hawaii | No | Yes | Yes | No | n/a | n/a |
| Idaho Power | Idaho | Yes | No | No | No | n/a | n/a |
| Delmarva | Maryland | Yes | Yes | No | Yes | 10% of base rate | Soft |
| PEPCO | Maryland | Yes | Yes | No | Yes | 10% of base rate | Soft |
| Baltimore Gas & Electric | Maryland | Yes | Yes | No | Yes | 10% of base rate | Soft |
| Fitchburg Gas & Electric | Massachusetts | No | Yes | Yes | Yes | 1% of total rev. | Soft |
| Western Mass. Elec. | Massachusetts | No | Yes | Yes | Yes | 1% of total rev. | Soft |
| Mass. Elec. and Nantucket | Massachusetts | No | Yes | Yes | Yes | 3% of total rev. | Soft |
| Central Hudson | New York | No | Yes | Yes | No | n/a | n/a |
| Consolidated Edison | New York | No | Yes | Yes | No | n/a | n/a |
| NYSEG | New York | No | Yes | Yes | No | n/a | n/a |
| Niagara Mohawk | New York | No | Yes | Yes | No | n/a | n/a |
| Orange & Rockland | New York | No | Yes | Yes | No | n/a | n/a |
| Rochester Gas & Elec. | New York | No | Yes | Yes | No | n/a | n/a |
| American Electric Power | Ohio | Yes | Yes | Yes | Yes | 3% of dist. rev. | Soft |
| Duke Energy Ohio | Ohio | Yes | No | Yes | Yes | 3% of dist. rev. | Soft |
| Portland General Electric | Oregon | Yes | No | No | Yes | 2% of total bill | Hard |
| Narragansett Electric | Rhode Island | No | Yes | Yes | No | n/a | n/a |
| Puget Sound Energy | Washington | Yes | Yes | No | Yes | 3% of rates | Soft |
| Wisconsin Public Service | Wisconsin | Yes | Yes | No | Yes | $14 mill. | Hard |
| | # Yes | 10 | 22 | 17 | 12 | | |

**Revenue Decoupling Criteria and Standards adopted by the Minnesota Public Utilities Commission in Docket No. E, G-999/CI-08-132**

Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling, dated June 19, 2009 beginning at page 7.

All utility decoupling pilot proposals under Minn. Stat. 216B.2412 shall provide the following information in the initial filing:

1. Purpose: All utilities shall state how their proposed decoupling mechanism adheres to the guiding statute. Each utility shall explain the purpose of their mechanism in the context of the Next Generation Energy Act of 2007's energy savings goals and how their mechanism will further the state policy of increased conservation investment.
2. Form: All utilities shall state the form of decoupling proposed and the purpose behind such choice. This should provide a detailed definition of what types of sales changes are included in the mechanism, i.e. weather-related sales changes, declining use per customer, etc., and the reason for such inclusion.
3. Cost of Capital: All utilities shall detail how their proposed mechanism will/will not impact the company's cost of capital.
4. Classes Included: All utilities must identify the rate classes involved in the pilot, as well as provide rationale for the inclusion of participating classes and the exclusion, if any, of other classes.
5. Mechanics: All utilities must provide precise detail on how the decoupling mechanism will operate, with the understanding that any decoupling pilot program be transparent and easy to follow from a customer perspective. Details to be provided are as follows:
    A. how rate adjustments will be calculated;
    B. when rate adjustments will be made;
    C. whether a rate cap or collar is provided to mitigate the risk of rate shock and justification for not so providing if a proposal lacks such safeguards;
    D. what portion of the customer's bill will be impacted by the true-up (volumetric vs. customer charge);
    E. how will the rate adjustment be displayed on the customer's bill;

   F. length of pilot (with the understanding that no pilot may extend longer than 36 months except through implementation in a rate case);
   G. how the decoupling mechanism will work in concert with any automatic recovery mechanism or financial incentive; this evaluation requires that all utilities provide a list of all automatic recovery mechanisms and incentives as well as justification for any such mechanism/incentive that the utility plans to continue throughout the course of the pilot including an explanation as to how the decoupling pilot mechanism, coupled with any other automatic adjustments and incentives, will not result in double recovery.
6. Service Quality: All utilities must provide detail, consistent with other service quality documentation, on how the utility plans to measure and maintain service quality under the pilot program. Phone answer time, gas emergency response time, missed appointments for service installations, time to reconnect service, and number of customers disconnected for non-payment should all be addressed in a pilot service quality evaluation.
7. Review: All utility pilot proposals shall be reviewed yearly. If the Commission determines that the pilot is harming ratepayers and/or failing to meet objectives, the Commission may suspend the pilot at any time or recommend modifications. As part of this annual review, all utilities shall provide information that shall be specified in an evaluation plan established as part of the pilot plan that shall include, but not be limited to the following information:
   A. total adjustments by class
   B. total adjustment charges collected
   C. number of customer complaints
   D. has the pilot stabilized revenues for the class(es) under the pilot and how has such stabilization impacted the utility's overall risk profile
   E. comparison of how revenues under traditional regulation would have differed from those collected under the decoupling pilot
   F. is the utility meeting energy efficiency savings goals? has the decoupling pilot influenced the achievement or likelihood of achievement of those goals?
   G. problems encountered and improvements/suggestions for the future.
8. Pilot Implementation:

A. Pilot proposals should be filed and implemented within a rate case; or
B. Pilot proposals may be filed outside of a rate case if the following conditions are met:
    (1) updated sales forecasts are provided with the pilot proposal;
    (2) detailed evaluation of how any decrease in risk as a result of the pilot proposal will impact the cost of capital; and
    (3) proposals are filed within one year of the final Commission order in a rate case.
C. Class Exclusion. The Commission requires that all decoupling pilot programs be implemented in more than one customer class.
D. Deadline for filing Pilot Programs
    (1) All utilities shall file a non-binding notice of intent as to their plans for filing a decoupling pilot by June 1, 2010.
    (2) All pilot proposals shall be filed by December 30, 2011.

Revenue Decoupling Model



**Residential RDM Rate Calculation**

| Residential TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01 | 427,855,354 | 373,745,099 | 369,256,223 | 305,419,219 | 330,726,778 | 416,384,868 | 511,094,084 | 469,753,320 | 352,528,244 | 348,627,215 | 356,142,553 | 410,536,346 | 4,672,069,303 |
| RES_A02 | 54,935 | 49,639 | 49,204 | 37,058 | 38,744 | 47,205 | 55,913 | 52,687 | 39,992 | 40,395 | 46,458 | 56,752 | 568,982 |
| RES_A02_Off | 142,849 | 123,178 | 117,156 | 87,069 | 85,907 | 93,937 | 99,333 | 85,993 | 73,237 | 79,704 | 96,656 | 132,758 | 1,217,777 |
| RES_A03 | 313,470,522 | 265,967,885 | 260,351,662 | 220,960,789 | 243,746,026 | 318,536,428 | 381,249,446 | 339,564,247 | 271,858,913 | 253,863,645 | 264,736,791 | 307,297,540 | 3,441,603,896 |
| RES_A04 | 51,059 | 46,051 | 39,750 | 32,679 | 32,358 | 39,176 | 46,785 | 42,297 | 33,717 | 32,264 | 38,235 | 49,887 | 484,260 |
| RES_A04_Off | 124,608 | 102,082 | 90,967 | 73,742 | 71,758 | 77,704 | 80,357 | 65,559 | 58,766 | 63,454 | 79,515 | 112,055 | 1,000,567 |
| RES_A05 | 1,245,153 | 1,137,726 | 996,815 | 516,147 | 412,724 | 301,453 | 338,850 | 284,304 | 220,694 | 281,160 | 559,923 | 966,179 | 7,261,129 |
| RES_A05 - Optional | 17,680 | 16,154 | 14,154 | 7,329 | 5,860 | 6,466 | 7,268 | 6,098 | 4,734 | 3,992 | 7,950 | 13,719 | 111,405 |
| RES_A06 | 11,928 | 14,181 | 11,469 | 9,981 | 6,387 | 4,116 | 5,133 | 4,466 | 3,623 | 5,261 | 7,526 | 15,825 | 99,897 |
| RES_A06_Off | 493,618 | 448,726 | 425,454 | 216,578 | 132,398 | 67,368 | 44,661 | 38,471 | 39,849 | 95,598 | 222,226 | 397,237 | 2,622,185 |
| Residential TY 2015 kWh | 743,467,706 | 641,650,722 | 631,352,855 | 527,360,590 | 575,258,941 | 735,558,722 | 893,021,830 | 809,897,444 | 624,861,769 | 603,092,689 | 621,937,832 | 719,578,297 | 8,127,039,398 |

| Residential TY 2015 Energy Charge | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01, A03 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.086810 | 0.086810 | 0.086810 |
| RES_A02, A04 | 0.178480 | 0.178480 | 0.178480 | 0.178480 | 0.178480 | 0.216620 | 0.216620 | 0.216620 | 0.216620 | 0.178480 | 0.178480 | 0.178480 |
| RES_A02_Off, A04_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| RES_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| RES_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.046970 | 0.046970 | 0.046970 |
| RES_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| RES_A06_Off | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |

| Residential TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01 | 37,142,123 | 32,444,812 | 32,055,133 | 26,513,442 | 28,710,392 | 42,084,019 | 51,656,279 | 47,477,968 | 35,630,030 | 30,264,329 | 30,916,735 | 35,638,660 | 430,533,921 |
| RES_A02 | 9,805 | 8,859 | 8,782 | 6,614 | 6,915 | 10,226 | 12,112 | 11,413 | 8,663 | 7,210 | 8,292 | 10,129 | 109,020 |
| RES_A02_Off | 4,580 | 3,949 | 3,756 | 2,791 | 2,754 | 3,012 | 3,185 | 2,757 | 2,348 | 2,555 | 3,099 | 4,256 | 39,042 |
| RES_A03 | 27,212,376 | 23,088,672 | 22,601,128 | 19,181,606 | 21,159,593 | 32,194,477 | 38,532,882 | 34,319,758 | 27,476,780 | 22,037,903 | 22,981,801 | 26,676,499 | 317,463,475 |
| RES_A04 | 9,113 | 8,219 | 7,095 | 5,832 | 5,775 | 8,486 | 10,135 | 9,162 | 7,304 | 5,759 | 6,824 | 8,904 | 92,608 |
| RES_A04_Off | 3,995 | 3,273 | 2,916 | 2,364 | 2,301 | 2,491 | 2,576 | 2,102 | 1,884 | 2,034 | 2,549 | 3,592 | 32,078 |
| RES_A05 | 58,485 | 53,439 | 46,820 | 24,243 | 19,386 | 14,159 | 15,916 | 13,354 | 10,366 | 13,206 | 26,300 | 45,381 | 341,055 |
| RES_A05 Optional | 830 | 759 | 665 | 344 | 275 | 654 | 735 | 616 | 478 | 188 | 373 | 644 | 6,562 |
| RES_A06 | 3,817 | 4,538 | 3,670 | 3,194 | 2,044 | 1,317 | 1,643 | 1,429 | 1,159 | 1,684 | 2,408 | 5,064 | 31,967 |
| RES_A06_Off | 13,950 | 12,681 | 12,023 | 6,120 | 3,742 | 1,904 | 1,262 | 1,087 | 1,126 | 2,702 | 6,280 | 11,226 | 74,103 |
| Residential TY 2015 Energy Chg Rev | 64,459,074 | 55,629,202 | 54,741,988 | 45,746,553 | 49,913,176 | 74,320,744 | 90,236,723 | 81,839,647 | 63,140,139 | 52,337,568 | 53,954,661 | 62,404,357 | 748,723,831 |

| Residential TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 2,371,662 | 2,046,866 | 2,014,016 | 1,682,280 | 1,835,076 | 2,346,432 | 2,848,740 | 2,583,573 | 1,993,309 | 1,923,866 | 1,983,982 | 2,295,455 | 25,925,256 |
| Res Energy Chg Rev w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 | 722,798,575 |

| **FRC = TY 2015 Fixed Rev per Cust** | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 |
| TY 2015 Customer Count | 1,075,105 | 1,076,198 | 1,076,713 | 1,076,258 | 1,075,853 | 1,074,944 | 1,074,792 | 1,076,013 | 1,076,239 | 1,077,942 | 1,077,850 | 1,078,421 |
| **FRC** | **58** | **50** | **49** | **41** | **45** | **67** | **81** | **74** | **57** | **47** | **48** | **56** |

| **FEC = TY 2015 Fixed Energy Chg** | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 |
| TY 2015 kWh | 743,467,706 | 641,650,722 | 631,352,855 | 527,360,590 | 575,258,941 | 735,558,722 | 893,021,830 | 809,897,444 | 624,861,769 | 603,092,689 | 621,937,832 | 719,578,297 |
| **FEC** | **0.0835106** | **0.0835070** | **0.0835159** | **0.0835562** | **0.0835764** | **0.0978499** | **0.0978565** | **0.0978594** | **0.0978566** | **0.0835920** | **0.0835625** | **0.0835335** |

Revenue Decoupling Model

**YEAR 1 Residential**

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 58 | 50 | 49 | 41 | 45 | 67 | 81 | 74 | 57 | 47 | 48 | 56 | |
| C = 2015 Actual Customer Count | 1,079,601 | 1,080,824 | 1,081,274 | 1,080,741 | 1,080,246 | 1,079,344 | 1,079,189 | 1,080,399 | 1,080,639 | 1,082,349 | 1,082,257 | 1,082,814 | |
| 2015 Allowed Revenue | 62,347,056 | 53,812,658 | 52,951,330 | 44,247,816 | 48,274,415 | 72,268,920 | 87,745,490 | 79,579,135 | 61,396,817 | 50,619,811 | 52,183,172 | 60,353,759 | 725,780,378 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0835106 | 0.0835070 | 0.0835159 | 0.0835562 | 0.0835764 | 0.0978499 | 0.0978565 | 0.0978594 | 0.0978566 | 0.0835920 | 0.0835625 | 0.0835335 | |
| WN kWh = 2015 Actual WN Sales | 733,349,155 | 631,682,467 | 621,940,750 | 518,609,873 | 566,460,518 | 727,794,279 | 886,490,381 | 803,131,840 | 619,170,860 | 597,457,368 | 616,930,239 | 715,036,893 | |
| 2015 Actual Revenue | 61,242,406 | 52,749,917 | 51,941,913 | 43,333,095 | 47,342,759 | 71,214,562 | 86,748,839 | 78,593,997 | 60,589,937 | 49,942,635 | 51,552,233 | 59,729,543 | 714,981,833 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 62,347,056 | 53,812,658 | 52,951,330 | 44,247,816 | 48,274,415 | 72,268,920 | 87,745,490 | 79,579,135 | 61,396,817 | 50,619,811 | 52,183,172 | 60,353,759 | |
| Actual Revenue | 61,242,406 | 52,749,917 | 51,941,913 | 43,333,095 | 47,342,759 | 71,214,562 | 86,748,839 | 78,593,997 | 60,589,937 | 49,942,635 | 51,552,233 | 59,729,543 | |
| Under / (Over) Collection | 1,104,650 | 1,062,741 | 1,009,418 | 914,721 | 931,657 | 1,054,357 | 996,651 | 985,138 | 806,880 | 677,176 | 630,939 | 624,216 | 10,798,545 |

| | |
|---|---|
| TY 2015 Total Revenue | 1,085,638,488 |
| 5% of Total Revenue | 54,281,924 |
| Apr 2016 - Mar 2017 Sales (kWh) | 8,064,433,023 |
| RDM Rider Rate Cap | 0.006731 |

| | |
|---|---|
| Under / (Over) $ | 10,798,545 |
| Apr 2016 - Mar 2017 Sales (kWh) | 8,064,433,023 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.001339** |

**YEAR 2 Residential**

| **2016 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 58 | 50 | 49 | 41 | 45 | 67 | 81 | 74 | 57 | 47 | 48 | 56 | |
| C = 2016 Actual Customer Count | 1,083,975 | 1,085,173 | 1,085,619 | 1,085,078 | 1,084,571 | 1,083,705 | 1,083,584 | 1,084,825 | 1,085,098 | 1,086,839 | 1,086,775 | 1,087,377 | |
| 2016 Allowed Revenue | 62,599,655 | 54,029,188 | 53,164,111 | 44,425,382 | 48,467,693 | 72,560,916 | 88,102,833 | 79,905,142 | 61,650,156 | 50,829,802 | 52,401,016 | 60,608,091 | 728,743,984 |

| **2016 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0835106 | 0.0835070 | 0.0835159 | 0.0835562 | 0.0835764 | 0.0978499 | 0.0978565 | 0.0978594 | 0.0978566 | 0.0835920 | 0.0835625 | 0.0835335 | |
| WN kWh = 2016 Actual WN Sales | 742,267,059 | 638,029,810 | 622,540,572 | 521,070,723 | 563,384,705 | 729,361,181 | 893,971,072 | 810,430,852 | 629,091,340 | 586,653,667 | 615,309,980 | 717,614,302 | |
| 2016 Actual Revenue | 61,987,145 | 53,279,964 | 51,992,007 | 43,538,715 | 47,085,693 | 71,367,883 | 87,480,873 | 79,308,274 | 61,560,721 | 49,039,532 | 51,416,840 | 59,944,843 | 718,002,489 |

**Year 2 (2016) - Under / (Over) Collection Calculation: 2016 Allowed Revenue - 2016 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 62,599,655 | 54,029,188 | 53,164,111 | 44,425,382 | 48,467,693 | 72,560,916 | 88,102,833 | 79,905,142 | 61,650,156 | 50,829,802 | 52,401,016 | 60,608,091 | |
| Actual Revenue | 61,987,145 | 53,279,964 | 51,992,007 | 43,538,715 | 47,085,693 | 71,367,883 | 87,480,873 | 79,308,274 | 61,560,721 | 49,039,532 | 51,416,840 | 59,944,843 | |
| Under / (Over) Collection | 612,510 | 749,224 | 1,172,103 | 886,667 | 1,382,000 | 1,193,033 | 621,961 | 596,868 | 89,435 | 1,790,269 | 984,176 | 663,248 | 10,741,494 |

| | |
|---|---|
| 2016 Total Revenue[1] | 1,085,638,488 |
| 5% of Total Revenue | 54,281,924 |
| Apr 2017 - Mar 2018 Sales (kWh) | 8,073,573,861 |
| RDM Rider Rate Cap | 0.006723 |

| | |
|---|---|
| Under / (Over) $ | 10,741,494 |
| Apr 2017 - Mar 2018 Sales (kWh) | 8,073,573,861 |
| **RDM Rider Rate ($/kWh) - Apr 2017 - Mar 2018** | **0.001330** |

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Revenue Decoupling Model



**Residential with Space Heating RDM Rate Calculation**

| Res Space Htg TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 19,250 | 18,947 | 16,630 | 12,336 | 16,771 | 15,213 | 17,621 | 17,314 | 15,597 | 17,730 | 20,088 | 18,259 | 205,756 |
| RSH_A01 | 31,717,218 | 29,106,460 | 22,798,004 | 14,187,703 | 14,346,535 | 11,395,087 | 13,553,422 | 12,698,695 | 11,526,266 | 14,176,630 | 22,268,712 | 28,723,102 | 226,497,833 |
| RSH_A02 | 23,777 | 22,491 | 19,096 | 10,450 | 9,587 | 8,567 | 9,655 | 11,912 | 9,052 | 11,228 | 17,740 | 19,556 | 173,110 |
| RSH_A02_Off | 51,971 | 45,574 | 40,446 | 21,374 | 20,086 | 16,480 | 17,401 | 19,406 | 15,940 | 20,489 | 33,862 | 39,612 | 342,640 |
| RSH_A03 | 16,777,939 | 15,335,255 | 12,081,840 | 8,087,127 | 8,193,100 | 7,283,073 | 8,463,174 | 7,870,653 | 7,277,175 | 8,312,687 | 12,214,042 | 15,587,459 | 127,483,523 |
| RSH_A04 | 23,720 | 22,550 | 16,897 | 11,474 | 11,801 | 11,598 | 14,060 | 14,206 | 12,553 | 13,031 | 18,135 | 22,966 | 192,992 |
| RSH_A04_Off | 56,079 | 48,071 | 38,301 | 24,866 | 25,218 | 21,933 | 23,881 | 26,319 | 21,470 | 25,316 | 35,500 | 48,767 | 395,722 |
| RSH_A05 | 3,750,698 | 3,437,075 | 2,674,676 | 1,365,668 | 1,155,670 | 762,626 | 970,793 | 867,527 | 758,565 | 970,429 | 2,255,089 | 3,598,574 | 22,567,391 |
| RSH_A05 Optional | 482,595 | 442,242 | 344,146 | 175,718 | 148,698 | 100,073 | 127,389 | 113,838 | 99,540 | 124,863 | 290,158 | 463,022 | 2,912,284 |
| RSH_A06 | 78 | 197 | 125 | 158 | 169 | 128 | 98 | 89 | 117 | 140 | 177 | 175 | 1,651 |
| RSH_A06_Off | 8,240 | 12,248 | 7,463 | 4,197 | 10,407 | 1,010 | 365 | 195 | 247 | 952 | 4,357 | 11,110 | 60,792 |
| Res Space Htg TY 2015 kWh | 52,911,565 | 48,491,110 | 38,037,623 | 23,901,071 | 23,938,041 | 19,615,787 | 23,197,859 | 21,640,155 | 19,736,523 | 23,673,496 | 37,157,860 | 48,532,601 | 380,833,693 |

| Res Space Htg TY 2015 Energy Chg | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.086810 | 0.086810 | 0.086810 |
| RSH_A01, A03 | 0.062470 | 0.062470 | 0.062470 | 0.062470 | 0.062470 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.062470 | 0.062470 | 0.062470 |
| RSH_A02, A04 | 0.117710 | 0.117710 | 0.117710 | 0.117710 | 0.117710 | 0.216620 | 0.216620 | 0.216620 | 0.216620 | 0.117710 | 0.117710 | 0.117710 |
| RSH_A02_Off, A04_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| RSH_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| RSH_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.046970 | 0.046970 | 0.046970 |
| RSH_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| RSH_A06_Off | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |

| Res SH TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 1,671 | 1,645 | 1,444 | 1,071 | 1,456 | 1,538 | 1,781 | 1,750 | 1,576 | 1,539 | 1,744 | 1,585 | 18,799 |
| RSH_A01 | 1,981,375 | 1,818,281 | 1,424,191 | 886,306 | 896,228 | 1,151,701 | 1,369,844 | 1,283,457 | 1,164,960 | 885,614 | 1,391,126 | 1,794,332 | 16,047,416 |
| RSH_A02 | 2,799 | 2,647 | 2,248 | 1,230 | 1,128 | 1,856 | 2,091 | 2,580 | 1,961 | 1,322 | 2,088 | 2,302 | 24,253 |
| RSH_A02_Off | 1,666 | 1,461 | 1,297 | 685 | 644 | 528 | 558 | 622 | 511 | 657 | 1,086 | 1,270 | 10,985 |
| RSH_A03 | 1,048,118 | 957,993 | 754,753 | 505,203 | 511,823 | 736,100 | 855,373 | 795,487 | 735,504 | 519,294 | 763,011 | 973,749 | 9,156,407 |
| RSH_A04 | 2,792 | 2,654 | 1,989 | 1,351 | 1,389 | 2,512 | 3,046 | 3,077 | 2,719 | 1,534 | 2,135 | 2,703 | 27,902 |
| RSH_A04_Off | 1,798 | 1,541 | 1,228 | 797 | 808 | 703 | 766 | 844 | 688 | 812 | 1,138 | 1,563 | 12,687 |
| RSH_A05 | 176,170 | 161,439 | 125,630 | 64,145 | 54,282 | 35,821 | 45,598 | 40,748 | 35,630 | 45,581 | 105,922 | 169,025 | 1,059,990 |
| RSH_A05 Optional | 22,668 | 20,772 | 16,165 | 8,253 | 6,984 | 10,114 | 12,875 | 11,506 | 10,061 | 5,865 | 13,629 | 21,748 | 160,639 |
| RSH_A06 | 25 | 63 | 40 | 51 | 54 | 41 | 31 | 29 | 37 | 45 | 57 | 56 | 528 |
| RSH_A06_Off | 233 | 346 | 211 | 119 | 294 | 29 | 10 | 6 | 7 | 27 | 123 | 314 | 1,718 |
| Res SH TY 2015 Energy Chg Rev | 3,239,314 | 2,968,843 | 2,329,194 | 1,469,211 | 1,475,091 | 1,940,943 | 2,291,974 | 2,140,105 | 1,953,654 | 1,462,288 | 2,282,058 | 2,968,648 | 26,521,324 |

| Res Space Htg TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 168,788 | 154,687 | 121,340 | 76,244 | 76,362 | 62,574 | 74,001 | 69,032 | 62,960 | 75,518 | 118,534 | 154,819 | 1,214,859 |
| Res Energy Chg Rev w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 | 25,306,464 |

| **FRC = TY 2015 Fixed Rev per Cust** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 |
| TY 2015 Customer Count | 31,833 | 31,869 | 31,930 | 31,959 | 31,956 | 31,950 | 31,965 | 31,980 | 31,995 | 32,011 | 32,027 | 32,044 |
| **FRC** | **96** | **88** | **69** | **44** | **44** | **59** | **69** | **65** | **59** | **43** | **68** | **88** |

| **FEC = TY 2015 Fixed Energy Chg** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 |
| TY 2015 kWh | 52,911,565 | 48,491,110 | 38,037,623 | 23,901,071 | 23,938,041 | 19,615,787 | 23,197,859 | 21,640,155 | 19,736,523 | 23,673,496 | 37,157,860 | 48,532,601 |
| **FEC** | **0.0580313** | **0.0580345** | **0.0580439** | **0.0582805** | **0.0584312** | **0.0957580** | **0.0956111** | **0.0957051** | **0.0957968** | **0.0585790** | **0.0582252** | **0.0579781** |

# Revenue Decoupling Model

## YEAR 1 - Residential with Space Heating

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 96 | 88 | 69 | 44 | 44 | 59 | 69 | 65 | 59 | 43 | 68 | 88 | |
| C = 2015 Actual Customer Count | 32,061 | 32,078 | 32,092 | 32,107 | 32,122 | 32,138 | 32,155 | 32,171 | 32,188 | 32,206 | 32,223 | 32,241 | |
| 2015 Allowed Revenue | 3,092,519 | 2,832,612 | 2,219,056 | 1,399,417 | 1,405,995 | 1,889,421 | 2,231,157 | 2,083,442 | 1,902,100 | 1,395,218 | 2,176,765 | 2,831,127 | 25,458,828 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0580313 | 0.0580345 | 0.0580439 | 0.0582805 | 0.0584312 | 0.0957580 | 0.0956111 | 0.0957051 | 0.0957968 | 0.0585790 | 0.0582252 | 0.0579781 | |
| WN kWh = 2015 Actual WN Sales | 52,782,650 | 47,929,698 | 37,955,682 | 23,955,046 | 24,021,489 | 19,366,489 | 23,159,870 | 21,617,034 | 19,782,416 | 23,792,347 | 36,719,918 | 48,493,043 | |
| 2015 Actual Revenue | 3,063,045 | 2,781,576 | 2,203,098 | 1,396,112 | 1,403,605 | 1,854,496 | 2,214,341 | 2,068,860 | 1,895,091 | 1,393,732 | 2,138,025 | 2,811,535 | 25,223,516 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 3,092,519 | 2,832,612 | 2,219,056 | 1,399,417 | 1,405,995 | 1,889,421 | 2,231,157 | 2,083,442 | 1,902,100 | 1,395,218 | 2,176,765 | 2,831,127 | |
| Actual Revenue | 3,063,045 | 2,781,576 | 2,203,098 | 1,396,112 | 1,403,605 | 1,854,496 | 2,214,341 | 2,068,860 | 1,895,091 | 1,393,732 | 2,138,025 | 2,811,535 | |
| Under / (Over) Collection | 29,473 | 51,037 | 15,958 | 3,305 | 2,390 | 34,925 | 16,816 | 14,582 | 7,009 | 1,486 | 38,740 | 19,592 | 235,312 |

| | |
|---|---|
| TY 2015 Total Revenue | 41,414,614 |
| 5% of Total Revenue | 2,070,731 |
| Apr 2016 - Mar 2017 Sales (kWh) | 386,474,589 |
| RDM Rider Rate Cap | 0.005358 |

| | |
|---|---|
| Under / (Over) $ | 235,312 |
| Apr 2016 - Mar 2017 Sales (kWh) | 386,474,589 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.000609** |

## YEAR 2 - Residential with Space Heating

| **2016 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 96 | 88 | 69 | 44 | 44 | 59 | 69 | 65 | 59 | 43 | 68 | 88 | |
| C = 2016 Actual Customer Count | 32,258 | 32,276 | 32,297 | 32,319 | 32,340 | 32,362 | 32,383 | 32,405 | 32,427 | 32,449 | 32,472 | 32,493 | |
| 2016 Allowed Revenue | 3,111,521 | 2,850,096 | 2,233,231 | 1,408,657 | 1,415,537 | 1,902,591 | 2,246,977 | 2,098,597 | 1,916,223 | 1,405,745 | 2,193,586 | 2,853,256 | 25,636,015 |

| **2016 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0580313 | 0.0580345 | 0.0580439 | 0.0582805 | 0.0584312 | 0.0957580 | 0.0956111 | 0.0957051 | 0.0957968 | 0.0585790 | 0.0582252 | 0.0579781 | |
| WN kWh = 2016 Actual WN Sales | 54,187,295 | 46,414,620 | 42,495,747 | 26,192,285 | 19,878,443 | 20,240,582 | 24,518,780 | 22,354,777 | 19,011,353 | 25,728,220 | 35,334,893 | 50,854,423 | |
| 2016 Actual Revenue | 3,144,559 | 2,693,649 | 2,466,621 | 1,526,499 | 1,161,522 | 1,938,198 | 2,344,268 | 2,139,466 | 1,821,226 | 1,507,134 | 2,057,382 | 2,948,443 | 25,748,965 |

**Year 2 (2016) - Under / (Over) Collection Calculation: 2016 Allowed Revenue - 2016 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 3,111,521 | 2,850,096 | 2,233,231 | 1,408,657 | 1,415,537 | 1,902,591 | 2,246,977 | 2,098,597 | 1,916,223 | 1,405,745 | 2,193,586 | 2,853,256 | |
| Actual Revenue | 3,144,559 | 2,693,649 | 2,466,621 | 1,526,499 | 1,161,522 | 1,938,198 | 2,344,268 | 2,139,466 | 1,821,226 | 1,507,134 | 2,057,382 | 2,948,443 | |
| Under / (Over) Collection | -33,038 | 156,448 | -233,390 | -117,842 | 254,015 | -35,607 | -97,291 | -40,869 | 94,997 | -101,389 | 136,204 | -95,188 | -112,950 |

| | |
|---|---|
| 2016 Total Revenue[1] | 41,414,614 |
| 5% of Total Revenue | 2,070,731 |
| Apr 2017 - Mar 2018 Sales (kWh) | 386,474,996 |
| RDM Rider Rate Cap | 0.005358 |

| | |
|---|---|
| Under / (Over) $ | -112,950 |
| Apr 2017 - Mar 2018 Sales (kWh) | 386,474,996 |
| **RDM Rider Rate ($/kWh) - Apr 2017 - Mar 2018** | **-0.000292** |

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Revenue Decoupling Model



**Small Commercial non-demand RDM Rate Calculation**

| SCI non-demand TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 254,024 | 248,335 | 258,861 | 184,544 | 96,631 | 61,149 | 54,499 | 58,258 | 45,602 | 42,237 | 77,541 | 153,701 | 1,535,382 |
| SCI_A05 Optional | 12,808 | 12,521 | 13,052 | 9,305 | 4,872 | 0 | 0 | 0 | 0 | 2,130 | 3,910 | 7,750 | 66,347 |
| SCI_A06 | 18,109 | 14,653 | 13,171 | 26,076 | 19,249 | 22,063 | 22,317 | 22,466 | 25,876 | 28,575 | 16,215 | 11,771 | 240,541 |
| SCI_A06 1S | 143,656 | 142,144 | 149,065 | 107,828 | 74,988 | 19,189 | 17,354 | 15,515 | 12,552 | 37,764 | 47,900 | 79,647 | 847,601 |
| SCI_A06 3S | 186,252 | 184,291 | 193,264 | 139,801 | 97,223 | 97,192 | 87,900 | 78,586 | 63,579 | 48,962 | 62,103 | 103,263 | 1,342,416 |
| SCI_A06 P | 7,794 | 7,712 | 8,087 | 5,850 | 4,068 | 0 | 0 | 0 | 0 | 2,049 | 2,599 | 4,321 | 42,480 |
| SCI_A09 | 2,501 | 2,390 | 2,509 | 2,462 | 2,541 | 2,521 | 2,634 | 2,348 | 2,128 | 2,288 | 2,388 | 2,398 | 29,110 |
| SCI_A10 | 77,354,696 | 71,350,465 | 73,381,813 | 68,000,687 | 67,494,140 | 68,321,702 | 76,540,496 | 76,406,372 | 66,396,951 | 63,523,823 | 61,325,645 | 66,657,846 | 836,754,635 |
| SCI_A11 | 25,096 | 23,167 | 25,033 | 24,444 | 25,230 | 25,595 | 25,032 | 22,287 | 19,556 | 20,140 | 19,831 | 20,448 | 275,860 |
| SCI_A12 | 1,490,935 | 1,393,115 | 1,464,663 | 1,346,903 | 1,303,930 | 1,227,053 | 1,220,513 | 1,167,015 | 1,056,260 | 1,105,063 | 1,212,910 | 1,383,594 | 15,371,954 |
| SCI_A12_Off | 3,175,501 | 2,894,501 | 2,908,517 | 2,748,343 | 2,765,887 | 2,602,107 | 2,555,705 | 2,381,962 | 2,159,749 | 2,292,678 | 2,452,748 | 2,817,753 | 31,755,453 |
| SCI_A16 | 1,219,663 | 1,093,152 | 1,124,759 | 1,105,674 | 1,149,599 | 1,109,476 | 1,131,775 | 1,056,621 | 946,917 | 1,041,807 | 1,073,011 | 1,137,832 | 13,190,288 |
| SCI_A18 | 2,394,670 | 2,174,187 | 2,136,171 | 2,090,325 | 2,561,330 | 2,611,614 | 2,421,494 | 2,182,897 | 1,954,500 | 2,165,333 | 2,307,911 | 2,354,167 | 27,354,598 |
| SCI_A22 | 195,473 | 180,251 | 194,807 | 195,563 | 210,719 | 205,888 | 208,768 | 188,787 | 172,708 | 185,759 | 193,405 | 200,556 | 2,332,684 |
| SCI non-demand TY 2015 kWh | 86,481,176 | 79,720,884 | 81,873,772 | 75,987,805 | 75,810,407 | 76,305,550 | 84,288,489 | 83,583,116 | 72,856,379 | 70,498,609 | 68,798,114 | 74,935,048 | 931,139,348 |

| SCI non-demand TY 2015 Energy Charg | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| SCI_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.094230 | 0.094230 | 0.094230 | 0.094230 | 0.046970 | 0.046970 | 0.046970 |
| SCI_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| SCI_A06 1S, A06_3S | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |
| SCI_A06 P | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 |
| SCI_A09, A10, A11 | 0.079970 | 0.079970 | 0.079970 | 0.079970 | 0.079970 | 0.094230 | 0.094230 | 0.094230 | 0.094230 | 0.079970 | 0.079970 | 0.079970 |
| SCI_A12 | 0.132560 | 0.132560 | 0.132560 | 0.132560 | 0.132560 | 0.162470 | 0.162470 | 0.162470 | 0.162470 | 0.132560 | 0.132560 | 0.132560 |
| SCI_A12_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| SCI_A16, A18, A22 | 0.067240 | 0.067240 | 0.067240 | 0.067240 | 0.067240 | 0.077700 | 0.077700 | 0.077700 | 0.077700 | 0.067240 | 0.067240 | 0.067240 |

| SCI non-dem TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 11,931 | 11,664 | 12,159 | 8,668 | 4,539 | 2,872 | 2,560 | 2,736 | 2,142 | 1,984 | 3,642 | 7,219 | 72,117 |
| SCI_A05 Optional | 602 | 588 | 613 | 437 | 229 | 0 | 0 | 0 | 0 | 100 | 184 | 364 | 3,116 |
| SCI_A06 | 5,795 | 4,689 | 4,215 | 8,344 | 6,160 | 7,060 | 7,142 | 7,189 | 8,280 | 9,144 | 5,189 | 3,767 | 76,973 |
| SCI_A06 1S | 4,060 | 4,017 | 4,213 | 3,047 | 2,119 | 542 | 490 | 438 | 355 | 1,067 | 1,354 | 2,251 | 23,953 |
| SCI_A06 3S | 5,263 | 5,208 | 5,462 | 3,951 | 2,748 | 2,747 | 2,484 | 2,221 | 1,797 | 1,384 | 1,755 | 2,918 | 37,937 |
| SCI_A06 P | 213 | 211 | 221 | 160 | 111 | 0 | 0 | 0 | 0 | 56 | 71 | 118 | 1,160 |
| SCI_A09 | 200 | 191 | 201 | 197 | 203 | 238 | 248 | 221 | 201 | 183 | 191 | 192 | 2,465 |
| SCI_A10 | 6,186,055 | 5,705,897 | 5,868,344 | 5,438,015 | 5,397,506 | 6,437,954 | 7,212,411 | 7,199,772 | 6,256,585 | 5,080,000 | 4,904,212 | 5,330,628 | 71,017,378 |
| SCI_A11 | 2,007 | 1,853 | 2,002 | 1,955 | 2,018 | 2,412 | 2,359 | 2,100 | 1,843 | 1,611 | 1,586 | 1,635 | 23,379 |
| SCI_A12 | 197,638 | 184,671 | 194,156 | 178,545 | 172,849 | 199,359 | 198,297 | 189,605 | 171,611 | 146,487 | 160,783 | 183,409 | 2,177,411 |
| SCI_A12_Off | 101,807 | 92,798 | 93,247 | 88,112 | 88,674 | 83,424 | 81,936 | 76,366 | 69,242 | 73,503 | 78,635 | 90,337 | 1,018,080 |
| SCI_A16 | 82,010 | 73,504 | 75,629 | 74,346 | 77,299 | 86,206 | 87,939 | 82,099 | 73,575 | 70,051 | 72,149 | 76,508 | 931,315 |
| SCI_A18 | 161,018 | 146,192 | 143,636 | 140,553 | 172,224 | 202,922 | 188,150 | 169,611 | 151,865 | 145,597 | 155,184 | 158,294 | 1,935,247 |
| SCI_A22 | 13,144 | 12,120 | 13,099 | 13,150 | 14,169 | 15,998 | 16,221 | 14,669 | 13,419 | 12,490 | 13,005 | 13,485 | 164,968 |
| SCI non-dem TY 2015 Energy Chg Rev | 6,771,742 | 6,243,602 | 6,417,194 | 5,959,480 | 5,940,847 | 7,041,734 | 7,800,237 | 7,747,029 | 6,750,913 | 5,543,657 | 5,397,939 | 5,871,126 | 77,485,500 |

| SCI non-demand TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 275,875 | 254,310 | 261,177 | 242,401 | 241,835 | 243,415 | 268,880 | 266,630 | 232,412 | 224,891 | 219,466 | 239,043 | 2,970,335 |
| Res Energy Chg Rev w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 | 74,515,166 |

| **FRC = TY 2015 Fixed Rev per Cust** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 |
| TY 2015 Customer Count | 85,498 | 85,584 | 85,628 | 85,593 | 85,559 | 85,486 | 85,474 | 85,569 | 85,587 | 85,720 | 85,712 | 85,757 |
| **FRC** | **76** | **70** | **72** | **67** | **67** | **80** | **88** | **87** | **76** | **62** | **60** | **66** |

| **FEC = TY 2015 Fixed Energy Chg** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 |
| TY 2015 kWh | 86,481,176 | 79,720,884 | 81,873,772 | 75,987,805 | 75,810,407 | 76,305,550 | 84,288,489 | 83,583,116 | 72,856,379 | 70,498,609 | 68,798,114 | 74,935,048 |
| **FEC** | **0.0751131** | **0.0751283** | **0.0751891** | **0.0752368** | **0.0751745** | **0.0890934** | **0.0893521** | **0.0894965** | **0.0894706** | **0.0754450** | **0.0752706** | **0.0751595** |

# Revenue Decoupling Model

**YEAR 1 - Small Commercial non-demand**

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 76 | 70 | 72 | 67 | 67 | 80 | 88 | 87 | 76 | 62 | 60 | 66 | |
| C = 2015 Actual Customer Count | 85,850 | 85,946 | 85,981 | 85,938 | 85,899 | 85,829 | 85,817 | 85,911 | 85,930 | 86,064 | 86,057 | 86,101 | |
| 2015 Allowed Revenue | 6,522,609 | 6,014,571 | 6,181,369 | 5,740,147 | 5,721,665 | 6,825,575 | 7,561,555 | 7,510,302 | 6,544,655 | 5,340,156 | 5,199,299 | 5,654,679 | 74,816,583 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0751131 | 0.0751283 | 0.0751891 | 0.0752368 | 0.0751745 | 0.0890934 | 0.0893521 | 0.0894965 | 0.0894706 | 0.0754450 | 0.0752706 | 0.0751595 | |
| WN kWh = 2015 Actual WN Sales | 86,324,781 | 79,344,007 | 83,105,236 | 75,167,453 | 76,102,826 | 75,197,305 | 83,764,014 | 83,476,688 | 72,757,213 | 70,392,492 | 68,705,811 | 74,828,273 | |
| 2015 Actual Revenue | 6,484,120 | 5,960,979 | 6,248,609 | 5,655,358 | 5,720,994 | 6,699,582 | 7,484,493 | 7,470,874 | 6,509,629 | 5,310,761 | 5,171,525 | 5,624,058 | 74,340,982 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 6,522,609 | 6,014,571 | 6,181,369 | 5,740,147 | 5,721,665 | 6,825,575 | 7,561,555 | 7,510,302 | 6,544,655 | 5,340,156 | 5,199,299 | 5,654,679 | |
| Actual Revenue | 6,484,120 | 5,960,979 | 6,248,609 | 5,655,358 | 5,720,994 | 6,699,582 | 7,484,493 | 7,470,874 | 6,509,629 | 5,310,761 | 5,171,525 | 5,624,058 | |
| Under / (Over) Collection | 38,489 | 53,593 | -67,241 | 84,789 | 671 | 125,993 | 77,062 | 39,428 | 35,026 | 29,395 | 27,774 | 30,621 | 475,600 |

| | |
|---|---|
| TY 2015 Total Revenue | 116,126,344 |
| 5% of Total Revenue | 5,806,317 |
| Apr 2016 - Mar 2017 Sales (kWh) | 927,659,958 |
| RDM Rider Rate Cap | 0.006259 |

| | |
|---|---|
| Under / (Over) $ | 475,600 |
| Apr 2016 - Mar 2017 Sales (kWh) | 927,659,958 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.000513** |

**YEAR 2 - Small Commercial non-demand**

| **2016 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 76 | 70 | 72 | 67 | 67 | 80 | 88 | 87 | 76 | 62 | 60 | 66 | |
| C = 2016 Actual Customer Count | 86,193 | 86,286 | 86,322 | 86,280 | 86,241 | 86,174 | 86,165 | 86,263 | 86,285 | 86,422 | 86,418 | 86,465 | |
| 2016 Allowed Revenue | 6,548,649 | 6,038,417 | 6,205,914 | 5,762,996 | 5,744,406 | 6,853,041 | 7,592,220 | 7,541,014 | 6,571,663 | 5,362,323 | 5,221,083 | 5,678,575 | 75,120,301 |

| **2016 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0751131 | 0.0751283 | 0.0751891 | 0.0752368 | 0.0751745 | 0.0890934 | 0.0893521 | 0.0894965 | 0.0894706 | 0.0754450 | 0.0752706 | 0.0751595 | |
| WN kWh = 2016 Actual WN Sales | 86,694,419 | 81,837,592 | 81,920,228 | 73,892,722 | 74,855,819 | 77,303,556 | 84,023,598 | 83,902,244 | 71,911,877 | 69,574,360 | 68,522,745 | 75,314,285 | |
| 2016 Actual Revenue | 6,511,884 | 6,148,317 | 6,159,510 | 5,559,451 | 5,627,251 | 6,887,235 | 7,507,688 | 7,508,959 | 6,433,996 | 5,249,037 | 5,157,746 | 5,660,586 | 74,411,662 |

**Year 2 (2016) - Under / (Over) Collection Calculation: 2016 Allowed Revenue - 2016 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 6,548,649 | 6,038,417 | 6,205,914 | 5,762,996 | 5,744,406 | 6,853,041 | 7,592,220 | 7,541,014 | 6,571,663 | 5,362,323 | 5,221,083 | 5,678,575 | |
| Actual Revenue | 6,511,884 | 6,148,317 | 6,159,510 | 5,559,451 | 5,627,251 | 6,887,235 | 7,507,688 | 7,508,959 | 6,433,996 | 5,249,037 | 5,157,746 | 5,660,586 | |
| Under / (Over) Collection | 36,764 | -109,900 | 46,404 | 203,544 | 117,155 | -34,194 | 84,532 | 32,055 | 137,667 | 113,286 | 63,338 | 17,989 | 708,639 |

| | |
|---|---|
| 2016 Total Revenue[1] | 116,126,344 |
| 5% of Total Revenue | 5,806,317 |
| Apr 2017 - Mar 2018 Sales (kWh) | 928,519,492 |
| RDM Rider Rate Cap | 0.006253 |

| | |
|---|---|
| Under / (Over) $ | 708,639 |
| Apr 2017 - Mar 2018 Sales (kWh) | 928,519,492 |
| **RDM Rider Rate ($/kWh) - Apr 2017 - Mar 2018** | **0.000763** |

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
**MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2**

PROPOSED

**REVENUE DECOUPLING MECHANISM RIDER**

Section No. 5
Original Sheet No. XX

**APPLICABILITY**
Applicable to bills for electric service provided under the Company's Residential and non-demand-metered Small General Service schedules, excluding lighting services.

**RIDER**
There shall be included on each customer's monthly bill a Revenue Decoupling Mechanism Rider (RDM Rider) which shall be the applicable Revenue Decoupling Mechanism Rider factor multiplied by the customer's monthly kWh electric consumption.

**DETERMINATION OF RDMR FACTORS**
<u>Annual RDM Rider Factor</u>
Each year during the term of this rider the Company will calculate an RDM Rider factor. This factor will be based on revenues billed through December 31 and applied to bills from April 1 through the March 31 of the following year. The RDM Rider factors are:

| | |
|---|---|
| Residential Standard | $0.001143 per kWh |
| Residential with Space Heating | $0.000461 per kWh |
| Small General Service (non-demand) | $0.000436 per kWh |

The calculation for the RDM Rider factor is:

Annual RDM Rider factor = RDM Rider Deferral / Forecasted Sales

For purposes of this section the following definitions apply:

| | |
|---|---|
| RDM Rider Deferral | <u>Annual RDM Rider Deferral</u> = the sum of the 12 monthly RDM Rider Deferrals plus any under- or over-recovery from previous Periods being deferred in the RDM Rider Deferral Account (see description below for Account details). In the first year of this rider there may be less than 12 monthly deferrals included. |
| Forecasted Sales | <u>Forecasted Usage for Year</u> = forecasted use in kWh from April 1 of the year in which the Annual RDM Rider factor is calculated through March 31 of the following year. |

The Annual RDM Rider factor to collect under-recovered revenues shall be capped at +5% of the total customer group revenue for each of the rate classes. The under-recovered revenues in excess of the +5% cap will be carried over to the RDM deferral account in the following year. The RDM Rider factor to return over-recovered revenues shall not be capped.

(Continued on Sheet No. 5-XX)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
**MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2**

PROPOSED

**REVENUE DECOUPLING MECHANISM RIDER**

Section No. 5
Original Sheet No. XX

RDM Rider Deferral Account

1. Each month the Company will calculate the Monthly RDM Rider Deferral, which will be entered in the RDM Rider Deferral Account. Separate deferrals will be calculated for Residential Standard, Residential with Electric Space Heating, and non-demand-metered Small General services.

   Monthly RDM Rider Deferral = (FRC x C) – (FEC x WN kWh)

   For purposes of this section, the following definitions apply:

   FRC — Fixed Revenue per Customer = Energy charge revenues divided by customer count, calculated monthly from test year data. Expressed in dollars per customer

   C — Customer Count = Actual customer count for deferral month.

   FEC — Fixed Energy Charge = Average energy charge for each month of test year. Expressed in dollars per kWh

   WN kWh — Weather-normalized Sales = Weather-normalized billed sales for deferral month. Expressed in kWh. Weather-normalized sales will be calculated using the same approach to weather normalization adopted in the Company's last electric general rate case (Docket No. E002/GR-13-868)

2. The Company will defer and amortize the Monthly RDM Deferrals in sub-account of Account 186.

3. Any under- or over-recovery of the Annual RDM RIder Deferral will be included as a deferral in the RDM Rider Deferral Account and reflected in the calculation of the following year's Annual RDM Rider factor.

**TERM**

The Company will begin collecting data for the initial deferral period on the first full month after receiving a Final Order from the Minnesota Public Utilities Commission ("Commission").

The Company will file its proposed Annual RDM Rider factor surcharge or credit with the Commission annually on April 1, beginning on April 1 following the Final Order from the Commission. The proposed rate will become effective on the filing date and remain in effect for the next 12 months, or until April 1 of the following year.

(Continued on Sheet No. 5-XX)

Revenue Decoupling Model - Sensitivity Analysis

**Residential RDM Rate Calculation** | Sales Sensitivity | Sales changes from Test Year: -3.0%

| Residential TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01 | 427,855,354 | 373,745,099 | 369,256,223 | 305,419,219 | 330,726,778 | 416,384,868 | 511,094,084 | 469,753,320 | 352,528,244 | 348,627,215 | 356,142,553 | 410,536,346 | 4,672,069,303 |
| RES_A02 | 54,935 | 49,639 | 49,204 | 37,058 | 38,744 | 47,205 | 55,913 | 52,687 | 39,992 | 40,395 | 46,458 | 56,752 | 568,982 |
| RES_A02_Off | 142,849 | 123,178 | 117,156 | 87,069 | 85,907 | 93,937 | 99,333 | 85,993 | 73,237 | 79,704 | 96,656 | 132,758 | 1,217,777 |
| RES_A03 | 313,470,522 | 265,967,885 | 260,351,662 | 220,960,789 | 243,746,026 | 318,536,428 | 381,249,446 | 339,564,247 | 271,858,913 | 253,863,645 | 264,736,791 | 307,297,540 | 3,441,603,896 |
| RES_A04 | 51,059 | 46,051 | 39,750 | 32,679 | 32,358 | 39,176 | 46,785 | 42,297 | 33,717 | 32,264 | 38,235 | 49,887 | 484,260 |
| RES_A04_Off | 124,608 | 102,082 | 90,967 | 73,742 | 71,758 | 77,704 | 80,357 | 65,559 | 58,766 | 63,454 | 79,515 | 112,055 | 1,000,567 |
| RES_A05 | 1,245,153 | 1,137,726 | 996,815 | 516,147 | 412,724 | 301,453 | 338,850 | 284,304 | 220,694 | 281,160 | 559,923 | 966,179 | 7,261,129 |
| RES_A05 - Optional | 17,680 | 16,154 | 14,154 | 7,329 | 5,860 | 6,466 | 7,268 | 6,098 | 4,734 | 3,992 | 7,950 | 13,719 | 111,405 |
| RES_A06 | 11,928 | 14,181 | 11,469 | 9,981 | 6,387 | 4,116 | 5,133 | 4,466 | 3,623 | 5,261 | 7,526 | 15,825 | 99,897 |
| RES_A06_Off | 493,618 | 448,726 | 425,454 | 216,578 | 132,398 | 67,368 | 44,661 | 38,471 | 39,849 | 95,598 | 222,226 | 397,237 | 2,622,185 |
| Residential TY 2015 kWh | 743,467,706 | 641,650,722 | 631,352,855 | 527,360,590 | 575,258,941 | 735,558,722 | 893,021,830 | 809,897,444 | 624,861,769 | 603,092,689 | 621,937,832 | 719,578,297 | 8,127,039,398 |

| Residential TY 2015 Energy Charge | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01, A03 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.086810 | 0.086810 | 0.086810 |
| RES_A02, A04 | 0.178480 | 0.178480 | 0.178480 | 0.178480 | 0.178480 | 0.216620 | 0.216620 | 0.216620 | 0.216620 | 0.178480 | 0.178480 | 0.178480 |
| RES_A02_Off, A04_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| RES_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| RES_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.046970 | 0.046970 | 0.046970 |
| RES_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| RES_A06_Off | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |

| Residential TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01 | 37,142,123 | 32,444,812 | 32,055,133 | 26,513,442 | 28,710,392 | 42,084,019 | 51,656,279 | 47,477,968 | 35,630,030 | 30,264,329 | 30,916,735 | 35,638,660 | 430,533,921 |
| RES_A02 | 9,805 | 8,859 | 8,782 | 6,614 | 6,915 | 10,226 | 12,112 | 11,413 | 8,663 | 7,210 | 8,292 | 10,129 | 109,020 |
| RES_A02_Off | 4,580 | 3,949 | 3,756 | 2,791 | 2,754 | 3,012 | 3,185 | 2,757 | 2,348 | 2,555 | 3,099 | 4,256 | 39,042 |
| RES_A03 | 27,212,376 | 23,088,672 | 22,601,128 | 19,181,606 | 21,159,593 | 32,194,477 | 38,532,882 | 34,319,758 | 27,476,780 | 22,037,903 | 22,981,801 | 26,676,499 | 317,463,475 |
| RES_A04 | 9,113 | 8,219 | 7,095 | 5,832 | 5,775 | 8,486 | 10,135 | 9,162 | 7,304 | 5,759 | 6,824 | 8,904 | 92,608 |
| RES_A04_Off | 3,995 | 3,273 | 2,916 | 2,364 | 2,301 | 2,491 | 2,576 | 2,102 | 1,884 | 2,034 | 2,549 | 3,592 | 32,078 |
| RES_A05 | 58,485 | 53,439 | 46,820 | 24,243 | 19,386 | 14,159 | 15,916 | 13,354 | 10,366 | 13,206 | 26,300 | 45,381 | 341,055 |
| RES_A05 Optional | 830 | 759 | 665 | 344 | 275 | 654 | 735 | 616 | 478 | 188 | 373 | 644 | 6,562 |
| RES_A06 | 3,817 | 4,538 | 3,670 | 3,194 | 2,044 | 1,317 | 1,643 | 1,429 | 1,159 | 1,684 | 2,408 | 5,064 | 31,967 |
| RES_A06_Off | 13,950 | 12,681 | 12,023 | 6,120 | 3,742 | 1,904 | 1,262 | 1,087 | 1,126 | 2,702 | 6,280 | 11,226 | 74,103 |
| Residential TY 2015 Energy Chg Rev | 64,459,074 | 55,629,202 | 54,741,988 | 45,746,553 | 49,913,176 | 74,320,744 | 90,236,723 | 81,839,647 | 63,140,139 | 52,337,568 | 53,954,661 | 62,404,357 | 748,723,831 |

| Residential TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 2,371,662 | 2,046,866 | 2,014,016 | 1,682,280 | 1,835,076 | 2,346,432 | 2,848,740 | 2,583,573 | 1,993,309 | 1,923,866 | 1,983,982 | 2,295,455 | 25,925,256 |
| Res Energy Chg Rev w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 | 722,798,575 |

| **FRC = TY 2015 Fixed Rev per Cust** | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 |
| TY 2015 Customer Count | 1,075,105 | 1,076,198 | 1,076,713 | 1,076,258 | 1,075,853 | 1,074,944 | 1,074,792 | 1,076,013 | 1,076,239 | 1,077,942 | 1,077,850 | 1,078,421 |
| **FRC** | **58** | **50** | **49** | **41** | **45** | **67** | **81** | **74** | **57** | **47** | **48** | **56** |

| **FEC = TY 2015 Fixed Energy Chg** | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 |
| TY 2015 kWh | 743,467,706 | 641,650,722 | 631,352,855 | 527,360,590 | 575,258,941 | 735,558,722 | 893,021,830 | 809,897,444 | 624,861,769 | 603,092,689 | 621,937,832 | 719,578,297 |
| **FEC** | **0.0835106** | **0.0835070** | **0.0835159** | **0.0835562** | **0.0835764** | **0.0978499** | **0.0978565** | **0.0978594** | **0.0978566** | **0.0835920** | **0.0835625** | **0.0835335** |

Revenue Decoupling Model - Sensitivity Analysis

**YEAR 1 Residential** | Sales Sensitivity | Sales changes from Test Year: -3.0%

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 58 | 50 | 49 | 41 | 45 | 67 | 81 | 74 | 57 | 47 | 48 | 56 | |
| C = 2015 Actual Customer Count | 1,075,105 | 1,076,198 | 1,076,713 | 1,076,258 | 1,075,853 | 1,074,944 | 1,074,792 | 1,076,013 | 1,076,239 | 1,077,942 | 1,077,850 | 1,078,421 | |
| 2015 Allowed Revenue | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 | 722,798,575 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0835106 | 0.0835070 | 0.0835159 | 0.0835562 | 0.0835764 | 0.0978499 | 0.0978565 | 0.0978594 | 0.0978566 | 0.0835920 | 0.0835625 | 0.0835335 | |
| WN kWh = 2015 Actual WN Sales | 721,163,675 | 622,401,200 | 612,412,269 | 511,539,773 | 558,001,173 | 713,491,961 | 866,231,176 | 785,600,520 | 606,115,916 | 584,999,909 | 603,279,697 | 697,990,948 | |
| 2015 Actual Revenue | 60,224,789 | 51,974,866 | 51,146,133 | 42,742,344 | 46,635,757 | 69,815,082 | 84,766,344 | 76,878,392 | 59,312,425 | 48,901,291 | 50,411,559 | 58,305,635 | 701,114,618 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 | |
| Actual Revenue | 60,224,789 | 51,974,866 | 51,146,133 | 42,742,344 | 46,635,757 | 69,815,082 | 84,766,344 | 76,878,392 | 59,312,425 | 48,901,291 | 50,411,559 | 58,305,635 | |
| Under / (Over) Collection | 1,862,622 | 1,607,470 | 1,581,839 | 1,321,928 | 1,442,343 | 2,159,229 | 2,621,640 | 2,377,682 | 1,834,405 | 1,512,411 | 1,559,120 | 1,803,267 | 21,683,957 |

| | |
|---|---|
| TY 2015 Total Revenue | 1,085,638,488 |
| 5% of Total Revenue | 54,281,924 |
| Apr 2016 - Mar 2017 Sales (kWh) | 8,064,433,023 |
| RDM Rider Rate Cap | 0.006731 |

| | |
|---|---|
| Under / (Over) $ | 21,683,957 |
| Apr 2016 - Mar 2017 Sales (kWh) | 8,064,433,023 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.002689** |

Revenue Decoupling Model - Sensitivity Analysis



**Residential with Space Heating RDM Rate Calc** | Sales Sensitivity | Sales changes from Test Year: -3.0%

| Res Space Htg TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 19,250 | 18,947 | 16,630 | 12,336 | 16,771 | 15,213 | 17,621 | 17,314 | 15,597 | 17,730 | 20,088 | 18,259 | 205,756 |
| RSH_A01 | 31,717,218 | 29,106,460 | 22,798,004 | 14,187,703 | 14,346,535 | 11,395,087 | 13,553,422 | 12,698,695 | 11,526,266 | 14,176,630 | 22,268,712 | 28,723,102 | 226,497,833 |
| RSH_A02 | 23,777 | 22,491 | 19,096 | 10,450 | 9,587 | 8,567 | 9,655 | 11,912 | 9,052 | 11,228 | 17,740 | 19,556 | 173,110 |
| RSH_A02_Off | 51,971 | 45,574 | 40,446 | 21,374 | 20,086 | 16,480 | 17,401 | 19,406 | 15,940 | 20,489 | 33,862 | 39,612 | 342,640 |
| RSH_A03 | 16,777,939 | 15,335,255 | 12,081,840 | 8,087,127 | 8,193,100 | 7,283,073 | 8,463,174 | 7,870,653 | 7,277,175 | 8,312,687 | 12,214,042 | 15,587,459 | 127,483,523 |
| RSH_A04 | 23,720 | 22,550 | 16,897 | 11,474 | 11,801 | 11,598 | 14,060 | 14,206 | 12,553 | 13,031 | 18,135 | 22,966 | 192,992 |
| RSH_A04_Off | 56,079 | 48,071 | 38,301 | 24,866 | 25,218 | 21,933 | 23,881 | 26,319 | 21,470 | 25,316 | 35,500 | 48,767 | 395,722 |
| RSH_A05 | 3,750,698 | 3,437,075 | 2,674,676 | 1,365,668 | 1,155,670 | 762,626 | 970,793 | 867,527 | 758,565 | 970,429 | 2,255,089 | 3,598,574 | 22,567,391 |
| RSH_A05 Optional | 482,595 | 442,242 | 344,146 | 175,718 | 148,698 | 100,073 | 127,389 | 113,838 | 99,540 | 124,863 | 290,158 | 463,022 | 2,912,284 |
| RSH_A06 | 78 | 197 | 125 | 158 | 169 | 128 | 98 | 89 | 117 | 140 | 177 | 175 | 1,651 |
| RSH_A06_Off | 8,240 | 12,248 | 7,463 | 4,197 | 10,407 | 1,010 | 365 | 195 | 247 | 952 | 4,357 | 11,110 | 60,792 |
| Res Space Htg TY 2015 kWh | 52,911,565 | 48,491,110 | 38,037,623 | 23,901,071 | 23,938,041 | 19,615,787 | 23,197,859 | 21,640,155 | 19,736,523 | 23,673,496 | 37,157,860 | 48,532,601 | 380,833,693 |

| Res Space Htg TY 2015 Energy Chg | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.086810 | 0.086810 | 0.086810 |
| RSH_A01, A03 | 0.062470 | 0.062470 | 0.062470 | 0.062470 | 0.062470 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.062470 | 0.062470 | 0.062470 |
| RSH_A02, A04 | 0.117710 | 0.117710 | 0.117710 | 0.117710 | 0.117710 | 0.216620 | 0.216620 | 0.216620 | 0.216620 | 0.117710 | 0.117710 | 0.117710 |
| RSH_A02_Off, A04_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| RSH_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| RSH_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.046970 | 0.046970 | 0.046970 |
| RSH_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| RSH_A06_Off | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |

| Res SH TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 1,671 | 1,645 | 1,444 | 1,071 | 1,456 | 1,538 | 1,781 | 1,750 | 1,576 | 1,539 | 1,744 | 1,585 | 18,799 |
| RSH_A01 | 1,981,375 | 1,818,281 | 1,424,191 | 886,306 | 896,228 | 1,151,701 | 1,369,844 | 1,283,457 | 1,164,960 | 885,614 | 1,391,126 | 1,794,332 | 16,047,416 |
| RSH_A02 | 2,799 | 2,647 | 2,248 | 1,230 | 1,128 | 1,856 | 2,091 | 2,580 | 1,961 | 1,322 | 2,088 | 2,302 | 24,253 |
| RSH_A02_Off | 1,666 | 1,461 | 1,297 | 685 | 644 | 528 | 558 | 622 | 511 | 657 | 1,086 | 1,270 | 10,985 |
| RSH_A03 | 1,048,118 | 957,993 | 754,753 | 505,203 | 511,823 | 736,100 | 855,373 | 795,487 | 735,504 | 519,294 | 763,011 | 973,749 | 9,156,407 |
| RSH_A04 | 2,792 | 2,654 | 1,989 | 1,351 | 1,389 | 2,512 | 3,046 | 3,077 | 2,719 | 1,534 | 2,135 | 2,703 | 27,902 |
| RSH_A04_Off | 1,798 | 1,541 | 1,228 | 797 | 808 | 703 | 766 | 844 | 688 | 812 | 1,138 | 1,563 | 12,687 |
| RSH_A05 | 176,170 | 161,439 | 125,630 | 64,145 | 54,282 | 35,821 | 45,598 | 40,748 | 35,630 | 45,581 | 105,922 | 169,025 | 1,059,990 |
| RSH_A05 Optional | 22,668 | 20,772 | 16,165 | 8,253 | 6,984 | 10,114 | 12,875 | 11,506 | 10,061 | 5,865 | 13,629 | 21,748 | 160,639 |
| RSH_A06 | 25 | 63 | 40 | 51 | 54 | 41 | 31 | 29 | 37 | 45 | 57 | 56 | 528 |
| RSH_A06_Off | 233 | 346 | 211 | 119 | 294 | 29 | 10 | 6 | 7 | 27 | 123 | 314 | 1,718 |
| Res SH TY 2015 Energy Chg Rev | 3,239,314 | 2,968,843 | 2,329,194 | 1,469,211 | 1,475,091 | 1,940,943 | 2,291,974 | 2,140,105 | 1,953,654 | 1,462,288 | 2,282,058 | 2,968,648 | 26,521,324 |

| Res Space Htg TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 168,788 | 154,687 | 121,340 | 76,244 | 76,362 | 62,574 | 74,001 | 69,032 | 62,960 | 75,518 | 118,534 | 154,819 | 1,214,859 |
| Res Energy Chg Rev w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 | 25,306,464 |

| **FRC = TY 2015 Fixed Rev per Cust** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 |
| TY 2015 Customer Count | 31,833 | 31,869 | 31,930 | 31,959 | 31,956 | 31,950 | 31,965 | 31,980 | 31,995 | 32,011 | 32,027 | 32,044 |
| **FRC** | **96** | **88** | **69** | **44** | **44** | **59** | **69** | **65** | **59** | **43** | **68** | **88** |

| **FEC = TY 2015 Fixed Energy Chg** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 |
| TY 2015 kWh | 52,911,565 | 48,491,110 | 38,037,623 | 23,901,071 | 23,938,041 | 19,615,787 | 23,197,859 | 21,640,155 | 19,736,523 | 23,673,496 | 37,157,860 | 48,532,601 |
| **FEC** | **0.0580313** | **0.0580345** | **0.0580439** | **0.0582805** | **0.0584312** | **0.0957580** | **0.0956111** | **0.0957051** | **0.0957968** | **0.0585790** | **0.0582252** | **0.0579781** |

## Revenue Decoupling Model - Sensitivity Analysis

| **YEAR 1 - Residential with Space Heating** | | Sales Sensitivity | | Sales changes from Test Year: | | -3.0% | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
| FRC | 96 | 88 | 69 | 44 | 44 | 59 | 69 | 65 | 59 | 43 | 68 | 88 | |
| C = 2015 Actual Customer Count | 31,833 | 31,869 | 31,930 | 31,959 | 31,956 | 31,950 | 31,965 | 31,980 | 31,995 | 32,011 | 32,027 | 32,044 | |
| 2015 Allowed Revenue | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 | 25,306,464 |
| | | | | | | | | | | | | | |
| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
| FEC | 0.0580313 | 0.0580345 | 0.0580439 | 0.0582805 | 0.0584312 | 0.0957580 | 0.0956111 | 0.0957051 | 0.0957968 | 0.0585790 | 0.0582252 | 0.0579781 | |
| WN kWh = 2015 Actual WN Sales | 51,324,219 | 47,036,377 | 36,896,495 | 23,184,039 | 23,219,900 | 19,027,314 | 22,501,923 | 20,990,951 | 19,144,427 | 22,963,291 | 36,043,124 | 47,076,623 | |
| 2015 Actual Revenue | 2,978,411 | 2,729,732 | 2,141,618 | 1,351,177 | 1,356,767 | 1,822,018 | 2,151,434 | 2,008,941 | 1,833,974 | 1,345,167 | 2,098,619 | 2,729,414 | 24,547,270 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 | |
| Actual Revenue | 2,978,411 | 2,729,732 | 2,141,618 | 1,351,177 | 1,356,767 | 1,822,018 | 2,151,434 | 2,008,941 | 1,833,974 | 1,345,167 | 2,098,619 | 2,729,414 | |
| Under / (Over) Collection | 92,116 | 84,425 | 66,236 | 41,789 | 41,962 | 56,351 | 66,539 | 62,132 | 56,721 | 41,603 | 64,906 | 84,415 | 759,194 |

| | |
|---|---|
| TY 2015 Total Revenue | 41,414,614 |
| 5% of Total Revenue | 2,070,731 |
| Apr 2016 - Mar 2017 Sales (kWh) | 386,474,589 |
| RDM Rider Rate Cap | 0.005358 |

| | |
|---|---|
| Under / (Over) $ | 759,194 |
| Apr 2016 - Mar 2017 Sales (kWh) | 386,474,589 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.001964** |

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

## Revenue Decoupling Model - Sensitivity Analysis

**Small Commercial non-demand RDM Rate Calc** | Sales Sensitivity | Sales changes from Test Year: -3.0%

| SCI non-demand TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 254,024 | 248,335 | 258,861 | 184,544 | 96,631 | 61,149 | 54,499 | 58,258 | 45,602 | 42,237 | 77,541 | 153,701 | 1,535,382 |
| SCI_A05 Optional | 12,808 | 12,521 | 13,052 | 9,305 | 4,872 | 0 | 0 | 0 | 0 | 2,130 | 3,910 | 7,750 | 66,347 |
| SCI_A06 | 18,109 | 14,653 | 13,171 | 26,076 | 19,249 | 22,063 | 22,317 | 22,466 | 25,876 | 28,575 | 16,215 | 11,771 | 240,541 |
| SCI_A06 1S | 143,656 | 142,144 | 149,065 | 107,828 | 74,988 | 19,189 | 17,354 | 15,515 | 12,552 | 37,764 | 47,900 | 79,647 | 847,601 |
| SCI_A06 3S | 186,252 | 184,291 | 193,264 | 139,801 | 97,223 | 97,192 | 87,900 | 78,586 | 63,579 | 48,962 | 62,103 | 103,263 | 1,342,416 |
| SCI_A06 P | 7,794 | 7,712 | 8,087 | 5,850 | 4,068 | 0 | 0 | 0 | 0 | 2,049 | 2,599 | 4,321 | 42,480 |
| SCI_A09 | 2,501 | 2,390 | 2,509 | 2,462 | 2,541 | 2,521 | 2,634 | 2,348 | 2,128 | 2,288 | 2,388 | 2,398 | 29,110 |
| SCI_A10 | 77,354,696 | 71,350,465 | 73,381,813 | 68,000,687 | 67,494,140 | 68,321,702 | 76,540,496 | 76,406,372 | 66,396,951 | 63,523,823 | 61,325,645 | 66,657,846 | 836,754,635 |
| SCI_A11 | 25,096 | 23,167 | 25,033 | 24,444 | 25,230 | 25,595 | 25,032 | 22,287 | 19,556 | 20,140 | 19,831 | 20,448 | 275,860 |
| SCI_A12 | 1,490,935 | 1,393,115 | 1,464,663 | 1,346,903 | 1,303,930 | 1,227,053 | 1,220,513 | 1,167,015 | 1,056,260 | 1,105,063 | 1,212,910 | 1,383,594 | 15,371,954 |
| SCI_A12_Off | 3,175,501 | 2,894,501 | 2,908,517 | 2,748,343 | 2,765,887 | 2,602,107 | 2,555,705 | 2,381,962 | 2,159,749 | 2,292,678 | 2,452,748 | 2,817,753 | 31,755,453 |
| SCI_A16 | 1,219,663 | 1,093,152 | 1,124,759 | 1,105,674 | 1,149,599 | 1,109,476 | 1,131,775 | 1,056,621 | 946,917 | 1,041,807 | 1,073,011 | 1,137,832 | 13,190,288 |
| SCI_A18 | 2,394,670 | 2,174,187 | 2,136,171 | 2,090,325 | 2,561,330 | 2,611,614 | 2,421,494 | 2,182,897 | 1,954,500 | 2,165,333 | 2,307,911 | 2,354,167 | 27,354,598 |
| SCI_A22 | 195,473 | 180,251 | 194,807 | 195,563 | 210,719 | 205,888 | 208,768 | 188,787 | 172,708 | 185,759 | 193,405 | 200,556 | 2,332,684 |
| SCI non-demand TY 2015 kWh | 86,481,176 | 79,720,884 | 81,873,772 | 75,987,805 | 75,810,407 | 76,305,550 | 84,288,489 | 83,583,116 | 72,856,379 | 70,498,609 | 68,798,114 | 74,935,048 | 931,139,348 |

| SCI non-demand TY 2015 Energy Charg | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| SCI_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.094230 | 0.094230 | 0.094230 | 0.094230 | 0.046970 | 0.046970 | 0.046970 |
| SCI_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| SCI_A06 1S, A06_3S | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |
| SCI_A06 P | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 |
| SCI_A09, A10, A11 | 0.079970 | 0.079970 | 0.079970 | 0.079970 | 0.079970 | 0.094230 | 0.094230 | 0.094230 | 0.094230 | 0.079970 | 0.079970 | 0.079970 |
| SCI_A12 | 0.132560 | 0.132560 | 0.132560 | 0.132560 | 0.132560 | 0.162470 | 0.162470 | 0.162470 | 0.162470 | 0.132560 | 0.132560 | 0.132560 |
| SCI_A12_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| SCI_A16, A18, A22 | 0.067240 | 0.067240 | 0.067240 | 0.067240 | 0.067240 | 0.077700 | 0.077700 | 0.077700 | 0.077700 | 0.067240 | 0.067240 | 0.067240 |

| SCI non-dem TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 11,931 | 11,664 | 12,159 | 8,668 | 4,539 | 2,872 | 2,560 | 2,736 | 2,142 | 1,984 | 3,642 | 7,219 | 72,117 |
| SCI_A05 Optional | 602 | 588 | 613 | 437 | 229 | 0 | 0 | 0 | 0 | 100 | 184 | 364 | 3,116 |
| SCI_A06 | 5,795 | 4,689 | 4,215 | 8,344 | 6,160 | 7,060 | 7,142 | 7,189 | 8,280 | 9,144 | 5,189 | 3,767 | 76,973 |
| SCI_A06 1S | 4,060 | 4,017 | 4,213 | 3,047 | 2,119 | 542 | 490 | 438 | 355 | 1,067 | 1,354 | 2,251 | 23,953 |
| SCI_A06 3S | 5,263 | 5,208 | 5,462 | 3,951 | 2,748 | 2,747 | 2,484 | 2,221 | 1,797 | 1,384 | 1,755 | 2,918 | 37,937 |
| SCI_A06 P | 213 | 211 | 221 | 160 | 111 | 0 | 0 | 0 | 0 | 56 | 71 | 118 | 1,160 |
| SCI_A09 | 200 | 191 | 201 | 197 | 203 | 238 | 248 | 221 | 201 | 183 | 191 | 192 | 2,465 |
| SCI_A10 | 6,186,055 | 5,705,897 | 5,868,344 | 5,438,015 | 5,397,506 | 6,437,954 | 7,212,411 | 7,199,772 | 6,256,585 | 5,080,000 | 4,904,212 | 5,330,628 | 71,017,378 |
| SCI_A11 | 2,007 | 1,853 | 2,002 | 1,955 | 2,018 | 2,412 | 2,359 | 2,100 | 1,843 | 1,611 | 1,586 | 1,635 | 23,379 |
| SCI_A12 | 197,638 | 184,671 | 194,156 | 178,545 | 172,849 | 199,359 | 198,297 | 189,605 | 171,611 | 146,487 | 160,783 | 183,409 | 2,177,411 |
| SCI_A12_Off | 101,807 | 92,798 | 93,247 | 88,112 | 88,674 | 83,424 | 81,936 | 76,366 | 69,242 | 73,503 | 78,635 | 90,337 | 1,018,080 |
| SCI_A16 | 82,010 | 73,504 | 75,629 | 74,346 | 77,299 | 86,206 | 87,939 | 82,099 | 73,575 | 70,051 | 72,149 | 76,508 | 931,315 |
| SCI_A18 | 161,018 | 146,192 | 143,636 | 140,553 | 172,224 | 202,922 | 188,150 | 169,611 | 151,865 | 145,597 | 155,184 | 158,294 | 1,935,247 |
| SCI_A22 | 13,144 | 12,120 | 13,099 | 13,150 | 14,169 | 15,998 | 16,221 | 14,669 | 13,419 | 12,490 | 13,005 | 13,485 | 164,968 |
| SCI non-dem TY 2015 Energy Chg Rev | 6,771,742 | 6,243,602 | 6,417,194 | 5,959,480 | 5,940,847 | 7,041,734 | 7,800,237 | 7,747,029 | 6,750,913 | 5,543,657 | 5,397,939 | 5,871,126 | 77,485,500 |

| SCI non-demand TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 275,875 | 254,310 | 261,177 | 242,401 | 241,835 | 243,415 | 268,880 | 266,630 | 232,412 | 224,891 | 219,466 | 239,043 | 2,970,335 |
| Res Energy Chg Rev w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 | 74,515,166 |

| **FRC = TY 2015 Fixed Rev per Cust** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 |
| TY 2015 Customer Count | 85,498 | 85,584 | 85,628 | 85,593 | 85,559 | 85,486 | 85,474 | 85,569 | 85,587 | 85,720 | 85,712 | 85,757 |
| **FRC** | **76** | **70** | **72** | **67** | **67** | **80** | **88** | **87** | **76** | **62** | **60** | **66** |

| **FEC = TY 2015 Fixed Energy Chg** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 |
| TY 2015 kWh | 86,481,176 | 79,720,884 | 81,873,772 | 75,987,805 | 75,810,407 | 76,305,550 | 84,288,489 | 83,583,116 | 72,856,379 | 70,498,609 | 68,798,114 | 74,935,048 |
| **FEC** | **0.0751131** | **0.0751283** | **0.0751891** | **0.0752368** | **0.0751745** | **0.0890934** | **0.0893521** | **0.0894965** | **0.0894706** | **0.0754450** | **0.0752706** | **0.0751595** |

Revenue Decoupling Model - Sensitivity Analysis



**YEAR 1 - Small Commercial non-demand**

| Sales Sensitivity | Sales changes from Test Year: | -3.0% |
|---|---|---|

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 76 | 70 | 72 | 67 | 67 | 80 | 88 | 87 | 76 | 62 | 60 | 66 | |
| C = 2015 Actual Customer Count | 85,498 | 85,584 | 85,628 | 85,593 | 85,559 | 85,486 | 85,474 | 85,569 | 85,587 | 85,720 | 85,712 | 85,757 | |
| 2015 Allowed Revenue | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 | 74,515,166 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0751131 | 0.0751283 | 0.0751891 | 0.0752368 | 0.0751745 | 0.0890934 | 0.0893521 | 0.0894965 | 0.0894706 | 0.0754450 | 0.0752706 | 0.0751595 | |
| WN kWh = 2015 Actual WN Sales | 83,886,741 | 77,329,258 | 79,417,559 | 73,708,171 | 73,536,095 | 74,016,383 | 81,759,834 | 81,075,622 | 70,670,687 | 68,383,650 | 66,734,171 | 72,686,997 | |
| 2015 Actual Revenue | 6,300,991 | 5,809,614 | 5,971,336 | 5,545,566 | 5,528,042 | 6,594,369 | 7,305,416 | 7,255,987 | 6,322,946 | 5,159,204 | 5,023,119 | 5,463,121 | 72,279,711 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 | |
| Actual Revenue | 6,300,991 | 5,809,614 | 5,971,336 | 5,545,566 | 5,528,042 | 6,594,369 | 7,305,416 | 7,255,987 | 6,322,946 | 5,159,204 | 5,023,119 | 5,463,121 | |
| Under / (Over) Collection | 194,876 | 179,679 | 184,681 | 171,512 | 170,970 | 203,950 | 225,941 | 224,412 | 195,555 | 159,563 | 155,354 | 168,962 | 2,235,455 |

| | |
|---|---|
| TY 2015 Total Revenue | 116,126,344 |
| 5% of Total Revenue | 5,806,317 |
| Apr 2016 - Mar 2017 Sales (kWh) | 927,659,958 |
| RDM Rider Rate Cap | 0.006259 |

| | |
|---|---|
| Under / (Over) $ | 2,235,455 |
| Apr 2016 - Mar 2017 Sales (kWh) | 927,659,958 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.002410** |

Revenue Decoupling Model - Sensitivity Analysis

**Residential RDM Rate Calculation** | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

| Residential TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01 | 427,855,354 | 373,745,099 | 369,256,223 | 305,419,219 | 330,726,778 | 416,384,868 | 511,094,084 | 469,753,320 | 352,528,244 | 348,627,215 | 356,142,553 | 410,536,346 | 4,672,069,303 |
| RES_A02 | 54,935 | 49,639 | 49,204 | 37,058 | 38,744 | 47,205 | 55,913 | 52,687 | 39,992 | 40,395 | 46,458 | 56,752 | 568,982 |
| RES_A02_Off | 142,849 | 123,178 | 117,156 | 87,069 | 85,907 | 93,937 | 99,333 | 85,993 | 73,237 | 79,704 | 96,656 | 132,758 | 1,217,777 |
| RES_A03 | 313,470,522 | 265,967,885 | 260,351,662 | 220,960,789 | 243,746,026 | 318,536,428 | 381,249,446 | 339,564,247 | 271,858,913 | 253,863,645 | 264,736,791 | 307,297,540 | 3,441,603,896 |
| RES_A04 | 51,059 | 46,051 | 39,750 | 32,679 | 32,358 | 39,176 | 46,785 | 42,297 | 33,717 | 32,264 | 38,235 | 49,887 | 484,260 |
| RES_A04_Off | 124,608 | 102,082 | 90,967 | 73,742 | 71,758 | 77,704 | 80,357 | 65,559 | 58,766 | 63,454 | 79,515 | 112,055 | 1,000,567 |
| RES_A05 | 1,245,153 | 1,137,726 | 996,815 | 516,147 | 412,724 | 301,453 | 338,850 | 284,304 | 220,694 | 281,160 | 559,923 | 966,179 | 7,261,129 |
| RES_A05 - Optional | 17,680 | 16,154 | 14,154 | 7,329 | 5,860 | 6,466 | 7,268 | 6,098 | 4,734 | 3,992 | 7,950 | 13,719 | 111,405 |
| RES_A06 | 11,928 | 14,181 | 11,469 | 9,981 | 6,387 | 4,116 | 5,133 | 4,466 | 3,623 | 5,261 | 7,526 | 15,825 | 99,897 |
| RES_A06_Off | 493,618 | 448,726 | 425,454 | 216,578 | 132,398 | 67,368 | 44,661 | 38,471 | 39,849 | 95,598 | 222,226 | 397,237 | 2,622,185 |
| Residential TY 2015 kWh | 743,467,706 | 641,650,722 | 631,352,855 | 527,360,590 | 575,258,941 | 735,558,722 | 893,021,830 | 809,897,444 | 624,861,769 | 603,092,689 | 621,937,832 | 719,578,297 | 8,127,039,398 |

| Residential TY 2015 Energy Charge | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01, A03 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.086810 | 0.086810 | 0.086810 |
| RES_A02, A04 | 0.178480 | 0.178480 | 0.178480 | 0.178480 | 0.178480 | 0.216620 | 0.216620 | 0.216620 | 0.216620 | 0.178480 | 0.178480 | 0.178480 |
| RES_A02_Off, A04_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| RES_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| RES_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.046970 | 0.046970 | 0.046970 |
| RES_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| RES_A06_Off | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |

| Residential TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RES_A01 | 37,142,123 | 32,444,812 | 32,055,133 | 26,513,442 | 28,710,392 | 42,084,019 | 51,656,279 | 47,477,968 | 35,630,030 | 30,264,329 | 30,916,735 | 35,638,660 | 430,533,921 |
| RES_A02 | 9,805 | 8,859 | 8,782 | 6,614 | 6,915 | 10,226 | 12,112 | 11,413 | 8,663 | 7,210 | 8,292 | 10,129 | 109,020 |
| RES_A02_Off | 4,580 | 3,949 | 3,756 | 2,791 | 2,754 | 3,012 | 3,185 | 2,757 | 2,348 | 2,555 | 3,099 | 4,256 | 39,042 |
| RES_A03 | 27,212,376 | 23,088,672 | 22,601,128 | 19,181,606 | 21,159,593 | 32,194,477 | 38,532,882 | 34,319,758 | 27,476,780 | 22,037,903 | 22,981,801 | 26,676,499 | 317,463,475 |
| RES_A04 | 9,113 | 8,219 | 7,095 | 5,832 | 5,775 | 8,486 | 10,135 | 9,162 | 7,304 | 5,759 | 6,824 | 8,904 | 92,608 |
| RES_A04_Off | 3,995 | 3,273 | 2,916 | 2,364 | 2,301 | 2,491 | 2,576 | 2,102 | 1,884 | 2,034 | 2,549 | 3,592 | 32,078 |
| RES_A05 | 58,485 | 53,439 | 46,820 | 24,243 | 19,386 | 14,159 | 15,916 | 13,354 | 10,366 | 13,206 | 26,300 | 45,381 | 341,055 |
| RES_A05 Optional | 830 | 759 | 665 | 344 | 275 | 654 | 735 | 616 | 478 | 188 | 373 | 644 | 6,562 |
| RES_A06 | 3,817 | 4,538 | 3,670 | 3,194 | 2,044 | 1,317 | 1,643 | 1,429 | 1,159 | 1,684 | 2,408 | 5,064 | 31,967 |
| RES_A06_Off | 13,950 | 12,681 | 12,023 | 6,120 | 3,742 | 1,904 | 1,262 | 1,087 | 1,126 | 2,702 | 6,280 | 11,226 | 74,103 |
| Residential TY 2015 Energy Chg Rev | 64,459,074 | 55,629,202 | 54,741,988 | 45,746,553 | 49,913,176 | 74,320,744 | 90,236,723 | 81,839,647 | 63,140,139 | 52,337,568 | 53,954,661 | 62,404,357 | 748,723,831 |

| Residential TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 2,371,662 | 2,046,866 | 2,014,016 | 1,682,280 | 1,835,076 | 2,346,432 | 2,848,740 | 2,583,573 | 1,993,309 | 1,923,866 | 1,983,982 | 2,295,455 | 25,925,256 |
| Res Energy Chg Rev w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 | 722,798,575 |

| **FRC = TY 2015 Fixed Rev per Cust** | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 |
| TY 2015 Customer Count | 1,075,105 | 1,076,198 | 1,076,713 | 1,076,258 | 1,075,853 | 1,074,944 | 1,074,792 | 1,076,013 | 1,076,239 | 1,077,942 | 1,077,850 | 1,078,421 |
| **FRC** | **58** | **50** | **49** | **41** | **45** | **67** | **81** | **74** | **57** | **47** | **48** | **56** |

| **FEC = TY 2015 Fixed Energy Chg** | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 62,087,412 | 53,582,336 | 52,727,973 | 44,064,272 | 48,078,100 | 71,974,312 | 87,387,983 | 79,256,075 | 61,146,830 | 50,413,703 | 51,970,680 | 60,108,902 |
| TY 2015 kWh | 743,467,706 | 641,650,722 | 631,352,855 | 527,360,590 | 575,258,941 | 735,558,722 | 893,021,830 | 809,897,444 | 624,861,769 | 603,092,689 | 621,937,832 | 719,578,297 |
| **FEC** | **0.0835106** | **0.0835070** | **0.0835159** | **0.0835562** | **0.0835764** | **0.0978499** | **0.0978565** | **0.0978594** | **0.0978566** | **0.0835920** | **0.0835625** | **0.0835335** |
| | | | | | | | | | | | | |
| TY 2015 UPC | 691.53 | 596.22 | 586.37 | 489.99 | 534.70 | 684.28 | 830.88 | 752.68 | 580.60 | 559.49 | 577.02 | 667.25 |

Revenue Decoupling Model - Sensitivity Analysis

**YEAR 1 Residential** | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 58 | 50 | 49 | 41 | 45 | 67 | 81 | 74 | 57 | 47 | 48 | 56 | |
| C = 2015 Actual Customer Count | 1,053,603 | 1,054,674 | 1,055,179 | 1,054,733 | 1,054,336 | 1,053,445 | 1,053,296 | 1,054,493 | 1,054,714 | 1,056,383 | 1,056,293 | 1,056,853 | |
| 2015 Allowed Revenue | 60,845,663 | 52,510,689 | 51,673,413 | 43,182,987 | 47,116,538 | 70,534,825 | 85,640,224 | 77,670,953 | 59,923,893 | 49,405,428 | 50,931,266 | 58,906,724 | 708,342,604 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0835106 | 0.0835070 | 0.0835159 | 0.0835562 | 0.0835764 | 0.0978499 | 0.0978565 | 0.0978594 | 0.0978566 | 0.0835920 | 0.0835625 | 0.0835335 | |
| WN kWh = 2015 Actual WN Sales | 728,598,352 | 628,817,707 | 618,725,798 | 516,813,378 | 563,753,763 | 720,847,548 | 875,161,394 | 793,699,495 | 612,364,534 | 591,030,836 | 609,499,075 | 705,186,731 | |
| 2015 Actual Revenue | 60,845,663 | 52,510,689 | 51,673,413 | 43,182,987 | 47,116,538 | 70,534,825 | 85,640,224 | 77,670,953 | 59,923,893 | 49,405,428 | 50,931,266 | 58,906,724 | 708,342,604 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 60,845,663 | 52,510,689 | 51,673,413 | 43,182,987 | 47,116,538 | 70,534,825 | 85,640,224 | 77,670,953 | 59,923,893 | 49,405,428 | 50,931,266 | 58,906,724 | |
| Actual Revenue | 60,845,663 | 52,510,689 | 51,673,413 | 43,182,987 | 47,116,538 | 70,534,825 | 85,640,224 | 77,670,953 | 59,923,893 | 49,405,428 | 50,931,266 | 58,906,724 | |
| Under / (Over) Collection | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | |
|---|---|
| TY 2015 Total Revenue | 1,085,638,488 |
| 5% of Total Revenue | 54,281,924 |
| Apr 2016 - Mar 2017 Sales (kWh) | 8,064,433,023 |
| RDM Rider Rate Cap | 0.006731 |

| | |
|---|---|
| Under / (Over) $ | 0 |
| Apr 2016 - Mar 2017 Sales (kWh) | 8,064,433,023 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.000000** |

## Revenue Decoupling Model - Sensitivity Analysis

**Residential with Space Heating RDM Rate Calc** | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

| Res Space Htg TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 19,250 | 18,947 | 16,630 | 12,336 | 16,771 | 15,213 | 17,621 | 17,314 | 15,597 | 17,730 | 20,088 | 18,259 | 205,756 |
| RSH_A01 | 31,717,218 | 29,106,460 | 22,798,004 | 14,187,703 | 14,346,535 | 11,395,087 | 13,553,422 | 12,698,695 | 11,526,266 | 14,176,630 | 22,268,712 | 28,723,102 | 226,497,833 |
| RSH_A02 | 23,777 | 22,491 | 19,096 | 10,450 | 9,587 | 8,567 | 9,655 | 11,912 | 9,052 | 11,228 | 17,740 | 19,556 | 173,110 |
| RSH_A02_Off | 51,971 | 45,574 | 40,446 | 21,374 | 20,086 | 16,480 | 17,401 | 19,406 | 15,940 | 20,489 | 33,862 | 39,612 | 342,640 |
| RSH_A03 | 16,777,939 | 15,335,255 | 12,081,840 | 8,087,127 | 8,193,100 | 7,283,073 | 8,463,174 | 7,870,653 | 7,277,175 | 8,312,687 | 12,214,042 | 15,587,459 | 127,483,523 |
| RSH_A04 | 23,720 | 22,550 | 16,897 | 11,474 | 11,801 | 11,598 | 14,060 | 14,206 | 12,553 | 13,031 | 18,135 | 22,966 | 192,992 |
| RSH_A04_Off | 56,079 | 48,071 | 38,301 | 24,866 | 25,218 | 21,933 | 23,881 | 26,319 | 21,470 | 25,316 | 35,500 | 48,767 | 395,722 |
| RSH_A05 | 3,750,698 | 3,437,075 | 2,674,676 | 1,365,668 | 1,155,670 | 762,626 | 970,793 | 867,527 | 758,565 | 970,429 | 2,255,089 | 3,598,574 | 22,567,391 |
| RSH_A05 Optional | 482,595 | 442,242 | 344,146 | 175,718 | 148,698 | 100,073 | 127,389 | 113,838 | 99,540 | 124,863 | 290,158 | 463,022 | 2,912,284 |
| RSH_A06 | 78 | 197 | 125 | 158 | 169 | 128 | 98 | 89 | 117 | 140 | 177 | 175 | 1,651 |
| RSH_A06_Off | 8,240 | 12,248 | 7,463 | 4,197 | 10,407 | 1,010 | 365 | 195 | 247 | 952 | 4,357 | 11,110 | 60,792 |
| Res Space Htg TY 2015 kWh | 52,911,565 | 48,491,110 | 38,037,623 | 23,901,071 | 23,938,041 | 19,615,787 | 23,197,859 | 21,640,155 | 19,736,523 | 23,673,496 | 37,157,860 | 48,532,601 | 380,833,693 |

| Res Space Htg TY 2015 Energy Chg | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.086810 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.086810 | 0.086810 | 0.086810 |
| RSH_A01, A03 | 0.062470 | 0.062470 | 0.062470 | 0.062470 | 0.062470 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.062470 | 0.062470 | 0.062470 |
| RSH_A02, A04 | 0.117710 | 0.117710 | 0.117710 | 0.117710 | 0.117710 | 0.216620 | 0.216620 | 0.216620 | 0.216620 | 0.117710 | 0.117710 | 0.117710 |
| RSH_A02_Off, A04_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| RSH_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| RSH_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.101070 | 0.101070 | 0.101070 | 0.101070 | 0.046970 | 0.046970 | 0.046970 |
| RSH_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| RSH_A06_Off | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |

| Res SH TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RSH_A00 | 1,671 | 1,645 | 1,444 | 1,071 | 1,456 | 1,538 | 1,781 | 1,750 | 1,576 | 1,539 | 1,744 | 1,585 | 18,799 |
| RSH_A01 | 1,981,375 | 1,818,281 | 1,424,191 | 886,306 | 896,228 | 1,151,701 | 1,369,844 | 1,283,457 | 1,164,960 | 885,614 | 1,391,126 | 1,794,332 | 16,047,416 |
| RSH_A02 | 2,799 | 2,647 | 2,248 | 1,230 | 1,128 | 1,856 | 2,091 | 2,580 | 1,961 | 1,322 | 2,088 | 2,302 | 24,253 |
| RSH_A02_Off | 1,666 | 1,461 | 1,297 | 685 | 644 | 528 | 558 | 622 | 511 | 657 | 1,086 | 1,270 | 10,985 |
| RSH_A03 | 1,048,118 | 957,993 | 754,753 | 505,203 | 511,823 | 736,100 | 855,373 | 795,487 | 735,504 | 519,294 | 763,011 | 973,749 | 9,156,407 |
| RSH_A04 | 2,792 | 2,654 | 1,989 | 1,351 | 1,389 | 2,512 | 3,046 | 3,077 | 2,719 | 1,534 | 2,135 | 2,703 | 27,902 |
| RSH_A04_Off | 1,798 | 1,541 | 1,228 | 797 | 808 | 703 | 766 | 844 | 688 | 812 | 1,138 | 1,563 | 12,687 |
| RSH_A05 | 176,170 | 161,439 | 125,630 | 64,145 | 54,282 | 35,821 | 45,598 | 40,748 | 35,630 | 45,581 | 105,922 | 169,025 | 1,059,990 |
| RSH_A05 Optional | 22,668 | 20,772 | 16,165 | 8,253 | 6,984 | 10,114 | 12,875 | 11,506 | 10,061 | 5,865 | 13,629 | 21,748 | 160,639 |
| RSH_A06 | 25 | 63 | 40 | 51 | 54 | 41 | 31 | 29 | 37 | 45 | 57 | 56 | 528 |
| RSH_A06_Off | 233 | 346 | 211 | 119 | 294 | 29 | 10 | 6 | 7 | 27 | 123 | 314 | 1,718 |
| Res SH TY 2015 Energy Chg Rev | 3,239,314 | 2,968,843 | 2,329,194 | 1,469,211 | 1,475,091 | 1,940,943 | 2,291,974 | 2,140,105 | 1,953,654 | 1,462,288 | 2,282,058 | 2,968,648 | 26,521,324 |

| Res Space Htg TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 168,788 | 154,687 | 121,340 | 76,244 | 76,362 | 62,574 | 74,001 | 69,032 | 62,960 | 75,518 | 118,534 | 154,819 | 1,214,859 |
| Res Energy Chg Rev w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 | 25,306,464 |

| **FRC = TY 2015 Fixed Rev per Cust** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 |
| TY 2015 Customer Count | 31,833 | 31,869 | 31,930 | 31,959 | 31,956 | 31,950 | 31,965 | 31,980 | 31,995 | 32,011 | 32,027 | 32,044 |
| **FRC** | **96** | **88** | **69** | **44** | **44** | **59** | **69** | **65** | **59** | **43** | **68** | **88** |

| **FEC = TY 2015 Fixed Energy Chg** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 3,070,526 | 2,814,157 | 2,207,854 | 1,392,966 | 1,398,729 | 1,878,369 | 2,217,973 | 2,071,073 | 1,890,695 | 1,386,770 | 2,163,525 | 2,813,829 |
| TY 2015 kWh | 52,911,565 | 48,491,110 | 38,037,623 | 23,901,071 | 23,938,041 | 19,615,787 | 23,197,859 | 21,640,155 | 19,736,523 | 23,673,496 | 37,157,860 | 48,532,601 |
| **FEC** | **0.0580313** | **0.0580345** | **0.0580439** | **0.0582805** | **0.0584312** | **0.0957580** | **0.0956111** | **0.0957051** | **0.0957968** | **0.0585790** | **0.0582252** | **0.0579781** |
| TY 2015 UPC | 1,662.16 | 1,521.58 | 1,191.28 | 747.87 | 749.09 | 613.95 | 725.73 | 676.68 | 616.86 | 739.54 | 1,160.20 | 1,514.56 |

Revenue Decoupling Model - Sensitivity Analysis

**YEAR 1 - Residential with Space Heating** | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 96 | 88 | 69 | 44 | 44 | 59 | 69 | 65 | 59 | 43 | 68 | 88 | |
| C = 2015 Actual Customer Count | 31,196 | 31,232 | 31,291 | 31,320 | 31,317 | 31,311 | 31,326 | 31,340 | 31,355 | 31,371 | 31,386 | 31,403 | |
| 2015 Allowed Revenue | 3,009,116 | 2,757,874 | 2,163,697 | 1,365,107 | 1,370,754 | 1,840,801 | 2,173,613 | 2,029,651 | 1,852,881 | 1,359,035 | 2,120,254 | 2,757,552 | 24,800,335 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0580313 | 0.0580345 | 0.0580439 | 0.0582805 | 0.0584312 | 0.0957580 | 0.0956111 | 0.0957051 | 0.0957968 | 0.0585790 | 0.0582252 | 0.0579781 | |
| WN kWh = 2015 Actual WN Sales | 51,853,334 | 47,521,288 | 37,276,871 | 23,423,050 | 23,459,280 | 19,223,472 | 22,733,902 | 21,207,352 | 19,341,793 | 23,200,026 | 36,414,703 | 47,561,949 | |
| 2015 Actual Revenue | 3,009,116 | 2,757,874 | 2,163,697 | 1,365,107 | 1,370,754 | 1,840,801 | 2,173,613 | 2,029,651 | 1,852,881 | 1,359,035 | 2,120,254 | 2,757,552 | 24,800,335 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 3,009,116 | 2,757,874 | 2,163,697 | 1,365,107 | 1,370,754 | 1,840,801 | 2,173,613 | 2,029,651 | 1,852,881 | 1,359,035 | 2,120,254 | 2,757,552 | |
| Actual Revenue | 3,009,116 | 2,757,874 | 2,163,697 | 1,365,107 | 1,370,754 | 1,840,801 | 2,173,613 | 2,029,651 | 1,852,881 | 1,359,035 | 2,120,254 | 2,757,552 | |
| Under / (Over) Collection | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | |
|---|---|
| TY 2015 Total Revenue | 41,414,614 |
| 5% of Total Revenue | 2,070,731 |
| Apr 2016 - Mar 2017 Sales (kWh) | 386,474,589 |
| RDM Rider Rate Cap | 0.005358 |

| | |
|---|---|
| Under / (Over) $ | 0 |
| Apr 2016 - Mar 2017 Sales (kWh) | 386,474,589 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.000000** |

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Revenue Decoupling Model - Sensitivity Analysis

**Small Commercial non-demand RDM Rate Calc** | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

| SCI non-demand TY 2015 kWh | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 254,024 | 248,335 | 258,861 | 184,544 | 96,631 | 61,149 | 54,499 | 58,258 | 45,602 | 42,237 | 77,541 | 153,701 | 1,535,382 |
| SCI_A05 Optional | 12,808 | 12,521 | 13,052 | 9,305 | 4,872 | 0 | 0 | 0 | 0 | 2,130 | 3,910 | 7,750 | 66,347 |
| SCI_A06 | 18,109 | 14,653 | 13,171 | 26,076 | 19,249 | 22,063 | 22,317 | 22,466 | 25,876 | 28,575 | 16,215 | 11,771 | 240,541 |
| SCI_A06 1S | 143,656 | 142,144 | 149,065 | 107,828 | 74,988 | 19,189 | 17,354 | 15,515 | 12,552 | 37,764 | 47,900 | 79,647 | 847,601 |
| SCI_A06 3S | 186,252 | 184,291 | 193,264 | 139,801 | 97,223 | 97,192 | 87,900 | 78,586 | 63,579 | 48,962 | 62,103 | 103,263 | 1,342,416 |
| SCI_A06 P | 7,794 | 7,712 | 8,087 | 5,850 | 4,068 | 0 | 0 | 0 | 0 | 2,049 | 2,599 | 4,321 | 42,480 |
| SCI_A09 | 2,501 | 2,390 | 2,509 | 2,462 | 2,541 | 2,521 | 2,634 | 2,348 | 2,128 | 2,288 | 2,388 | 2,398 | 29,110 |
| SCI_A10 | 77,354,696 | 71,350,465 | 73,381,813 | 68,000,687 | 67,494,140 | 68,321,702 | 76,540,496 | 76,406,372 | 66,396,951 | 63,523,823 | 61,325,645 | 66,657,846 | 836,754,635 |
| SCI_A11 | 25,096 | 23,167 | 25,033 | 24,444 | 25,230 | 25,595 | 25,032 | 22,287 | 19,556 | 20,140 | 19,831 | 20,448 | 275,860 |
| SCI_A12 | 1,490,935 | 1,393,115 | 1,464,663 | 1,346,903 | 1,303,930 | 1,227,053 | 1,220,513 | 1,167,015 | 1,056,260 | 1,105,063 | 1,212,910 | 1,383,594 | 15,371,954 |
| SCI_A12_Off | 3,175,501 | 2,894,501 | 2,908,517 | 2,748,343 | 2,765,887 | 2,602,107 | 2,555,705 | 2,381,962 | 2,159,749 | 2,292,678 | 2,452,748 | 2,817,753 | 31,755,453 |
| SCI_A16 | 1,219,663 | 1,093,152 | 1,124,759 | 1,105,674 | 1,149,599 | 1,109,476 | 1,131,775 | 1,056,621 | 946,917 | 1,041,807 | 1,073,011 | 1,137,832 | 13,190,288 |
| SCI_A18 | 2,394,670 | 2,174,187 | 2,136,171 | 2,090,325 | 2,561,330 | 2,611,614 | 2,421,494 | 2,182,897 | 1,954,500 | 2,165,333 | 2,307,911 | 2,354,167 | 27,354,598 |
| SCI_A22 | 195,473 | 180,251 | 194,807 | 195,563 | 210,719 | 205,888 | 208,768 | 188,787 | 172,708 | 185,759 | 193,405 | 200,556 | 2,332,684 |
| SCI non-demand TY 2015 kWh | 86,481,176 | 79,720,884 | 81,873,772 | 75,987,805 | 75,810,407 | 76,305,550 | 84,288,489 | 83,583,116 | 72,856,379 | 70,498,609 | 68,798,114 | 74,935,048 | 931,139,348 |

| SCI non-demand TY 2015 Energy Charg | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 |
| SCI_A05 Optional | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.046970 | 0.094230 | 0.094230 | 0.094230 | 0.094230 | 0.046970 | 0.046970 | 0.046970 |
| SCI_A06 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 | 0.320000 |
| SCI_A06 1S, A06_3S | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 | 0.028260 |
| SCI_A06 P | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 | 0.027302 |
| SCI_A09, A10, A11 | 0.079970 | 0.079970 | 0.079970 | 0.079970 | 0.079970 | 0.094230 | 0.094230 | 0.094230 | 0.094230 | 0.079970 | 0.079970 | 0.079970 |
| SCI_A12 | 0.132560 | 0.132560 | 0.132560 | 0.132560 | 0.132560 | 0.162470 | 0.162470 | 0.162470 | 0.162470 | 0.132560 | 0.132560 | 0.132560 |
| SCI_A12_Off | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 | 0.032060 |
| SCI_A16, A18, A22 | 0.067240 | 0.067240 | 0.067240 | 0.067240 | 0.067240 | 0.077700 | 0.077700 | 0.077700 | 0.077700 | 0.067240 | 0.067240 | 0.067240 |

| SCI non-dem TY 2015 Energy Chg Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCI_A05 | 11,931 | 11,664 | 12,159 | 8,668 | 4,539 | 2,872 | 2,560 | 2,736 | 2,142 | 1,984 | 3,642 | 7,219 | 72,117 |
| SCI_A05 Optional | 602 | 588 | 613 | 437 | 229 | 0 | 0 | 0 | 0 | 100 | 184 | 364 | 3,116 |
| SCI_A06 | 5,795 | 4,689 | 4,215 | 8,344 | 6,160 | 7,060 | 7,142 | 7,189 | 8,280 | 9,144 | 5,189 | 3,767 | 76,973 |
| SCI_A06 1S | 4,060 | 4,017 | 4,213 | 3,047 | 2,119 | 542 | 490 | 438 | 355 | 1,067 | 1,354 | 2,251 | 23,953 |
| SCI_A06 3S | 5,263 | 5,208 | 5,462 | 3,951 | 2,748 | 2,747 | 2,484 | 2,221 | 1,797 | 1,384 | 1,755 | 2,918 | 37,937 |
| SCI_A06 P | 213 | 211 | 221 | 160 | 111 | 0 | 0 | 0 | 0 | 56 | 71 | 118 | 1,160 |
| SCI_A09 | 200 | 191 | 201 | 197 | 203 | 238 | 248 | 221 | 201 | 183 | 191 | 192 | 2,465 |
| SCI_A10 | 6,186,055 | 5,705,897 | 5,868,344 | 5,438,015 | 5,397,506 | 6,437,954 | 7,212,411 | 7,199,772 | 6,256,585 | 5,080,000 | 4,904,212 | 5,330,628 | 71,017,378 |
| SCI_A11 | 2,007 | 1,853 | 2,002 | 1,955 | 2,018 | 2,412 | 2,359 | 2,100 | 1,843 | 1,611 | 1,586 | 1,635 | 23,379 |
| SCI_A12 | 197,638 | 184,671 | 194,156 | 178,545 | 172,849 | 199,359 | 198,297 | 189,605 | 171,611 | 146,487 | 160,783 | 183,409 | 2,177,411 |
| SCI_A12_Off | 101,807 | 92,798 | 93,247 | 88,112 | 88,674 | 83,424 | 81,936 | 76,366 | 69,242 | 73,503 | 78,635 | 90,337 | 1,018,080 |
| SCI_A16 | 82,010 | 73,504 | 75,629 | 74,346 | 77,299 | 86,206 | 87,939 | 82,099 | 73,575 | 70,051 | 72,149 | 76,508 | 931,315 |
| SCI_A18 | 161,018 | 146,192 | 143,636 | 140,553 | 172,224 | 202,922 | 188,150 | 169,611 | 151,865 | 145,597 | 155,184 | 158,294 | 1,935,247 |
| SCI_A22 | 13,144 | 12,120 | 13,099 | 13,150 | 14,169 | 15,998 | 16,221 | 14,669 | 13,419 | 12,490 | 13,005 | 13,485 | 164,968 |
| SCI non-dem TY 2015 Energy Chg Rev | 6,771,742 | 6,243,602 | 6,417,194 | 5,959,480 | 5,940,847 | 7,041,734 | 7,800,237 | 7,747,029 | 6,750,913 | 5,543,657 | 5,397,939 | 5,871,126 | 77,485,500 |

| SCI non-demand TY 2015 CCRC Rev | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCRC = $0.00319 per kWh | 275,875 | 254,310 | 261,177 | 242,401 | 241,835 | 243,415 | 268,880 | 266,630 | 232,412 | 224,891 | 219,466 | 239,043 | 2,970,335 |
| Res Energy Chg Rev w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 | 74,515,166 |

| **FRC = TY 2015 Fixed Rev per Cust** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 |
| TY 2015 Customer Count | 85,498 | 85,584 | 85,628 | 85,593 | 85,559 | 85,486 | 85,474 | 85,569 | 85,587 | 85,720 | 85,712 | 85,757 |
| **FRC** | **76** | **70** | **72** | **67** | **67** | **80** | **88** | **87** | **76** | **62** | **60** | **66** |

| **FEC = TY 2015 Fixed Energy Chg** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 Energy Revenue w/o CCRC | 6,495,867 | 5,989,293 | 6,156,017 | 5,717,079 | 5,699,012 | 6,798,319 | 7,531,356 | 7,480,399 | 6,518,501 | 5,318,767 | 5,178,473 | 5,632,083 |
| TY 2015 kWh | 86,481,176 | 79,720,884 | 81,873,772 | 75,987,805 | 75,810,407 | 76,305,550 | 84,288,489 | 83,583,116 | 72,856,379 | 70,498,609 | 68,798,114 | 74,935,048 |
| **FEC** | **0.0751131** | **0.0751283** | **0.0751891** | **0.0752368** | **0.0751745** | **0.0890934** | **0.0893521** | **0.0894965** | **0.0894706** | **0.0754450** | **0.0752706** | **0.0751595** |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TY 2015 UPC | 1,011.50 | 931.49 | 956.16 | 887.78 | 886.06 | 892.61 | 986.13 | 976.79 | 851.26 | 822.43 | 802.66 | 873.80 |

# Revenue Decoupling Model - Sensitivity Analysis

**YEAR 1 - Small Commercial non-demand** | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

| **2015 Allowed Rev = FRC * C** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FRC | 76 | 70 | 72 | 67 | 67 | 80 | 88 | 87 | 76 | 62 | 60 | 66 | |
| C = 2015 Actual Customer Count | 83,788 | 83,873 | 83,915 | 83,881 | 83,848 | 83,776 | 83,765 | 83,858 | 83,875 | 84,005 | 83,998 | 84,042 | |
| 2015 Allowed Revenue | 6,365,950 | 5,869,507 | 6,032,896 | 5,602,737 | 5,585,032 | 6,662,353 | 7,380,729 | 7,330,791 | 6,388,131 | 5,212,391 | 5,074,903 | 5,519,442 | 73,024,862 |

| **2015 Actual Rev = FEC * WN kWh** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEC | 0.0751131 | 0.0751283 | 0.0751891 | 0.0752368 | 0.0751745 | 0.0890934 | 0.0893521 | 0.0894965 | 0.0894706 | 0.0754450 | 0.0752706 | 0.0751595 | |
| WN kWh = 2015 Actual WN Sales | 84,751,552 | 78,126,466 | 80,236,297 | 74,468,049 | 74,294,199 | 74,779,439 | 82,602,719 | 81,911,454 | 71,399,251 | 69,088,636 | 67,422,152 | 73,436,347 | |
| 2015 Actual Revenue | 6,365,950 | 5,869,507 | 6,032,896 | 5,602,737 | 5,585,032 | 6,662,353 | 7,380,729 | 7,330,791 | 6,388,131 | 5,212,391 | 5,074,903 | 5,519,442 | 73,024,862 |

**Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Allowed Revenue | 6,365,950 | 5,869,507 | 6,032,896 | 5,602,737 | 5,585,032 | 6,662,353 | 7,380,729 | 7,330,791 | 6,388,131 | 5,212,391 | 5,074,903 | 5,519,442 | |
| Actual Revenue | 6,365,950 | 5,869,507 | 6,032,896 | 5,602,737 | 5,585,032 | 6,662,353 | 7,380,729 | 7,330,791 | 6,388,131 | 5,212,391 | 5,074,903 | 5,519,442 | |
| Under / (Over) Collection | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | |
|---|---|
| TY 2015 Total Revenue | 116,126,344 |
| 5% of Total Revenue | 5,806,317 |
| Apr 2016 - Mar 2017 Sales (kWh) | 927,659,958 |
| RDM Rider Rate Cap | 0.006259 |

| | |
|---|---|
| Under / (Over) $ | 0 |
| Apr 2016 - Mar 2017 Sales (kWh) | 927,659,958 |
| **RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017** | **0.000000** |

**2013 TY Revenues**
from September 19, 2013 Compliance Filing in Docket No. E002/GR-12-961

| | MWh | Base Fixed $1000s | Base Variable $1000s | Fuel $1000s | Riders $1000s | Total $1000s |
|---|---|---|---|---|---|---|
| Residential | 8,692,532 | 115,301 | 655,409 | 235,613 | 4,097 | 1,010,421 |
| Sm C&I Non-Demand | 984,589 | 10,212 | 70,640 | 27,590 | 464 | 108,906 |
| Total | 9,677,121 | 125,513 | 726,049 | 263,203 | 4,561 | 1,119,328 |
| | | | | | | |
| Fixed | | 125,513 | 15% | | | |
| Variable | | 726,049 | 85% | | | |
| Total | | 851,563 | | | | |

| | MWh | Base Fixed $1000s | Base Variable $1000s | Fuel $1000s | Riders $1000s | Total $1000s |
|---|---|---|---|---|---|---|
| C&I Demand | 20,920,504 | 511,350 | 564,527 | 556,610 | 9,861 | 1,642,348 |
| Public Authorities | 72,728 | 3,078 | 2,401 | 1,971 | 34 | 7,483 |
| Lighting | 174,426 | 20,698 | 1,779 | 3,463 | 82 | 26,022 |
| Total | 21,167,658 | 535,126 | 568,706 | 562,044 | 9,978 | 1,675,854 |
| | | | | | | |
| Fixed | | 535,126 | 48% | | | |
| Variable | | 568,706 | 52% | | | |
| Total | | 1,103,832 | | | | |

| | MWh | Base Fixed $1000s | Base Variable $1000s | Fuel $1000s | Riders $1000s | Total $1000s |
|---|---|---|---|---|---|---|
| Total | 30,844,779 | 660,640 | 1,294,755 | 825,247 | 14,539 | 2,795,181 |
| | | | | | | |
| Fixed | | 660,640 | 34% | | | |
| Variable | | 1,294,755 | 66% | | | |
| Total | | 1,955,395 | | | | |

**BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS**
**600 North Robert Street**
**St. Paul, MN 55101**

**FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION**
**121 Seventh Place East, Suite 350**
**St Paul, MN 55101-2147**

| | |
|---|---|
| **In the Matter of the Application of Otter Tail Power Company For Authority to Increase Rates for Electric Utility Service in Minnesota** | **PUC Docket No. E017/GR-15-1033**<br>**OAH Docket No. 8-2500-33355** |

**DIRECT TESTIMONY OF**

**MARK LOWRY**
**President**

**KAJA REBANE**
**Economist II**

**Pacific Economics Research LLC**

**On Behalf of**

**Fresh Energy**

## I. INTRODUCTION

**Q. Please state your names, occupations, and business addresses.**

A. We are Mark Newton Lowry and Kaja Rebane of Pacific Economics Group ("PEG") Research LLC. Our business address is 44 East Mifflin St., Suite 601, Madison, WI 53703.

**Q. On whose behalf are you testifying in this rate case proceeding?**

A. Our testimony is sponsored by Fresh Energy.

**Q. Dr. Lowry, what is your occupation and professional background?**

A. I am the President of PEG Research, a company in the Pacific Economics Group consortium that is prominent in the field of alternative regulation. I have almost thirty years of experience as an industry economist. Revenue decoupling, performance-based regulation, cost trackers, and other alternatives to traditional rate regulation --- sometimes jointly called alternative regulation ("Altreg") --- have been my chief professional focus for twenty-five years. I have testified dozens of times on Altreg issues. Work for a mix of well-known utilities, trade associations, regulatory commissions, environmental organizations, and other clients has given my practice a reputation for objectivity and dedication to good regulation. Our practice is multinational and has included extensive work in Canada.

Before joining PEG, I was for several years an Assistant Professor of Mineral Economics at the University Park campus of the Pennsylvania State University. I have also worked as a Vice President at Christensen Associates and as a visiting professor at l'Ecole des

Hautes Etudes Commerciales in Montreal. My resume includes an extensive list of publications and public appearances. A native of Cleveland, I attended Princeton University and hold a Ph.D. in Applied Economics from the University of Wisconsin ("UW") Madison. My resume can be found in Attachment 1.

**Q. Ms. Rebane, what is your occupation and professional background?**

A. I am a Level II Economist at PEG Research and have four years of experience as a professional energy economist. I hold an undergraduate degree in Biology from Stanford University, as well as Master's degrees in Applied Economics and Land Resources and a certificate in Energy Analysis and Policy from UW Madison. A Las Vegas native, I am pursuing a Ph.D. in Environment and Resources at UW Madison. My resume can be found in Attachment 2.

**Q. What issues does your testimony address?**

A. Otter Tail Power ("OTP") is in this proceeding proposing a change in its rate designs for small volume customers that substantially increases its fixed charges relative to volumetric charges. This will substantially reduce the incentives of small volume customers to adopt DERs. Fresh Energy has asked us to appraise the incentives that Otter Tail's proposed regulatory system provides for the Company to embrace efficient demand side management ("DSM"), distributed generation and storage ("DGS"), and other kinds of distributed energy resources ("DERs").

Following a general discussion of the poor incentives for utilities to embrace DERs under traditional rate regulation, we detail several touted Altreg remedies for improving these incentives and consider their pros and cons. After reviewing the situation of OTP, we then provide an analysis of their incentives to embrace efficient DERs and prescribe an alternative regulatory system that would produce better results. A report on our work for Fresh Energy is found in Attachment 3.

**Q. What do you conclude from your analysis of Otter Tail's situation and proposed regulatory system?**

A. Our general analysis of utility performance incentives and our review of the Company's situation suggests that Otter Tail does not have appropriately strong incentives to embrace efficient DERs. We find that even with the proposed hikes in customer charges, most revenue addressing costs that are fixed in the short run with respect to system use would continue to be addressed by usage charges. There is thus potentially a strong throughput incentive and a concomitant disincentive to embrace DERs even when they are the low cost option for customers and society.

Another cause for concern is the Company's weak incentive to contain many load-related costs. While the expected rate case cycle would provide some incentive to contain some load-related costs, most of OTP's load-related costs are subject to cost trackers or formula rates. Otter Tail's finances are also insensitive to many kinds of environmental damage that its operations cause.

**Q. Does the CIP Financial Incentive Mechanism help with this problem?**

A. Yes it does, but only with respect to conservation programs that it covers. This mechanism doesn't encourage Otter Tail to embrace DGS or a wide range of initiatives the Company can take to promote conservation and peak demand management.

Perhaps reflecting this, the Company's conservation goals only slightly exceed the statutory minimum. Instead of moving in the direction of time-sensitive pricing that could encourage more efficient DERs, Otter Tail is proposing a reduction in volumetric charges relative to fixed charges that discourages all forms of DERs for small-volume customers.

**Q. What do you recommend as an alternative to Otter Tail's proposal?**

A. Based on our analysis, we believe that reforms to OTP's regulatory system are needed to encourage efficient DERs. Most importantly, revenue decoupling should be instituted. This can immediately and completely remove the throughput-related disincentive to embrace efficient DGS and peak load management and the full range of initiatives that encourage conservation. Debate over future billing determinants can be reduced in forward test year rate cases. The institution of decoupling can buy OTP time to reconsider its rate designs to ensure that they send the right price signals for DERs, as required by Minnesota law.

We also believe that the MNCIP Financial Incentive Mechanism and tracker treatment of DSM expenses should continue in order to provide some positive incentive to use DSM for cost management. Additional reforms are needed to improve DER incentives that may go beyond what can be addressed in this rate case. These include the development of positive financial incentives for OTP to encourage efficient DGS, peak load management, and a wider range of conservation initiatives. A multiyear rate plan can further strengthen incentives to contain load-related capex.

**Q. Please provide some details of your proposed revenue decoupling system.**

A. We propose a revenue decoupling system broadly similar to that which the Commission approved for Xcel Energy in its last rate case.[1]

- Decoupling would apply to residential, farm, and general service (excluding large general service) customers.
- Separate baskets would apply to residential and farm services and to the general services. The use of multiple baskets protects customers in each basket from rate adjustments due to the demand trends of dissimilar customers.
- The proposed RDM would adjust all usage charges in a given service basket equiproportionately. Charges that fluctuate only with the number of customers (e.g., customer charges) would not be included in the RDM, as revenue collected through them is already decoupled from usage.
- The RDM would effect *full* decoupling subject to the constraint that rate increases due to the revenue decoupling mechanism would be capped at 3% annually. Residual revenue variances would be eligible for true-up in the following year.
- Revenue per customer would be decoupled, so that the revenue requirement of each service basket rises gradually with the number of customers in that basket.
- Decoupling adjustments would be applied in each month of the following April-March period.

[1] MNPUC Docket No. E-002/GR-13-868, May 2015.

- OTP would be required to file a plan proposing education and outreach program to customers explaining the goals and operations of its RDM program.
- The decoupling adjustment would appear as a separate rider on customers' bills to enhance transparency.

Illustrative revenue decoupling mechanisms and tariff sheets are found in the Appendix to our report.

**Q. Does this conclude your Direct Testimony?**

A. Yes it does.

# RESUME OF
# MARK NEWTON LOWRY

August 2016

**Home Address** 1511 Sumac Drive
Madison, WI 53705
(608) 233-4822

**Business Address** 44 E. Mifflin St., Suite 601
Madison, WI 53703
(608) 257-1522 Ext. 23

**Date of Birth** August 7, 1952

**Education** High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural & Resource Economics, University of Wisconsin-Madison, May 1984

**Relevant Work Experience, Primary Positions**

**Present Position** **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive and sole proprietor of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

**October 1998-February 2009** **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

**January 1993-October 1998** **Vice President**
**January 1989-December 1992** **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

**Aug. 1984-Dec. 1988** **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

**August 1983-July 1984** **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

**April 1982-August 1983** **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

**March 1981-March 1982** **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

**Relevant Work Experience, Visiting Positions:**

**May-August 1985** **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

**Major Consulting Projects**

1. Research on Gas Market Competition for a Western Electric Utility. 1981.
2. Research on the Natural Gas Policy Act for a Northeast Trade Association. 1981
3. Interruptible Service Research for an Industry Research Institute. 1989.
4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
6. PBR Consultation for a Southeast Gas Transmission Company. 1989.
7. Gas Transmission Productivity Research for a U.S. Trade Association. 1990.
8. Productivity Research for a Northeast Gas and Electric Utility. 1990-91.
9. Comprehensive Performance Indexes for a Northeast Gas and Electric Utility. 1990-1991.
10. PBR Consultation for a Southeast Electric Utility. 1991.
11. Research on Electric Revenue Adjustment Mechanisms for a Northeast Electric Utility. 1991.
12. Productivity Research for a Western Gas Distributor. 1991.
13. Cost Performance Indexes for a Northeast U.S. Gas and Electric Utility. 1991.
14. Gas Transmission Rate Design for a Western U.S. Electric Utility. 1991.
15. Gas Supply Cost Indexing for a Western U.S. Gas Distributor. 1992.
16. Gas Transmission Strategy for a Western Electric Utility. 1992.
17. Design and Negotiation of Comprehensive Benchmark Incentive Plans for a Northeast Gas and Electric Utility. 1992.
18. Gas Supply Cost Benchmarking and Testimony for a Northeast U.S. Gas Distributor, 1992.
19. Bundled Power Service Productivity Research for a Western Electric Utility. 1993-96.
20. Development of PBR Options for a Western Electric Utility. 1993.
21. Review of the Regional Gas Transmission Market for a Western Electric Utility. 1993.
22. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1993.

23. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1994.
24. Productivity Research for a Western Gas Distributor. 1994.
25. White Paper on Price Cap Regulation for a U.S. Trade Association. 1994.
26. Bundled Power Service Benchmarking for a Western Electric Utility. 1994.
27. White Paper on PBR for a U.S. Trade Association. 1995.
28. Productivity Research and PBR Plan Design for a Northeast Gas and Electric Company. 1995.
29. Regulatory Strategy for a Restructuring Canadian Electric Utility. 1995.
30. PBR Consultation for a Japanese Electric Utility. 1995.
31. Regulatory Strategy for a Restructuring Northeast Electric Utility. 1995.
32. Productivity Research and Plan Design Testimony for a Western Gas Distributor. 1995.
33. Productivity Testimony for a Northeast Gas Distributor. 1995.
34. Speech on PBR for a Western Electric Utility. 1995.
35. Development of a PBR Plan for a Midwest Gas Distributor. 1996.
36. Stranded Cost Recovery and Power Distribution PBR for a Northeast Electric Utility. 1996.
37. Benchmarking and Productivity Research and Testimony for a Northeast Gas Distributor. 1996.
38. Consultation on Gas Production, Transmission, and Distribution PBR for a Latin American Regulator. 1996.
39. Power Distribution Benchmarking for a Northeast Electric Utility. 1996.
40. Testimony on PBR for a Northeast Power Distributor. 1996.
41. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
42. Design of Gas Distributor Service Territories for a Latin American Regulator. 1996.
43. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
44. Service Quality PBR for a Canadian Gas Distributor. 1996.
45. Productivity and PBR Research and Testimony for a Canadian Gas Distributor. 1997.
46. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1997.
47. Design of a Price Cap Plan for a South American Regulator. 1997.
48. White Paper on Utility Brand Name Policy for a U.S. Trade Association. 1997.
49. Bundled Power Service Benchmarking and Testimony for a Western Electric Utility. 1997.
50. Review of a Power Purchase Contract Dispute for a Midwest City. 1997.
51. Research on Benchmarking and Stranded Cost Recovery for a U.S. Trade Association. 1997.
52. Research and Testimony on Productivity Trends for a Northeast Gas Distributor. 1997.
53. PBR Plan Design, Benchmarking, and Testimony for a Southeast Gas Distributor. 1997.
54. White Paper on Power Distribution PBR for a U.S. Trade Association. 1997-99.
55. White Paper and Public Appearances on PBR Options for Australian Power Distributors. 1997-98.
56. Gas and Power Distribution PBR Research and Testimony for a Western Energy Utility. 1997-98.
57. Research on the Cost Structure of Power Distribution for a U.S. Trade Association. 1998.
58. Research on Cross-Subsidization for a U.S. Trade Association. 1998.
59. Testimony on Brand Names for a U.S. Trade Association. 1998.
60. Research and Testimony on Economies of Scale in Power Supply for a Western Electric Utility. 1998.
61. PBR Plan Design and Testimony for a Western Electric Utility. 1998-99.
62. PBR and Bundled Power Service Testimony and Testimony for Two Southeast U.S. Electric Utilities. 1998-99.
63. Statistical Benchmarking for an Australian Power Distributor. 1998-9.
64. Testimony on Functional Separation of Power Generation and Delivery for a U.S. Trade Association. 1998.
65. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. 1998.
66. Consultation on PBR and Code of Conduct Issues for a Western Electric Utility. 1999.
67. PBR and Bundled Power Service Benchmarking Research and Testimony for a Southwest Electric Utility. 1999.

68. Power Transmission and Distribution Cost Benchmarking for a Western Electric Utility. 1999.
69. Cost Benchmarking for Three Australian Power Distributors. 1999.
70. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1999.
71. Benchmarking Research for an Australian Power Distributor. 2000.
72. Critique of a Commission-Sponsored Benchmarking Study for Three Australian Power Distributors. 2000.
73. Statistical Benchmarking for an Australian Power Transco. 2000.
74. PBR and Benchmarking Testimony for a Southwest Electric Utility. 2000.
75. PBR Workshop (for Regulators) for a Northeast Gas and Electric Utility. 2000.
76. Research on Economies of Scale and Scope for an Australian Electric Utility. 2000.
77. Research and Testimony on Economies of Scale in Power Delivery, Metering, and Billing for a Consortium of Northeast Electric Utilities. 2000.
78. Research and Testimony on Service Quality PBR for a Consortium of Northeast Energy Utilities. 2000.
79. Power and Natural Gas Procurement PBR for a Western Electric Utility. 2000.
80. PBR Plan Design for a Canadian Natural Gas Distributor. 2000.
81. TFP and Benchmarking Research for a Western Gas and Electric Utility. 2000.
82. E-Forum on PBR for Power Procurement for a U.S. Trade Association. 2001.
83. PBR Presentation to Florida's Energy 2000 Commission for a U.S. Trade Association. 2001.
84. Research on Power Market Competition for an Australian Electric Utility. 2001.
85. TFP and Other PBR Research and Testimony for a Northeast Power Distributor. 2000.
86. PBR and Productivity for a Canadian Electric Utility. 2002
87. Statistical Benchmarking for an Australian Power Transco. 2002.
88. PBR and Bundled Power Service Benchmarking Research and Testimony for a Midwest Energy Utility. 2002.
89. Consultation on the Future of Power Transmission and Distribution Regulation for a Western Electric Utility. 2002.
90. Benchmarking and Productivity Research and Testimony for Two Western U.S. Energy Distributors. 2002.
91. Workshop on PBR (for Regulators) for a Canadian Trade Association. 2003.
92. PBR, Productivity, and Benchmarking Research for a Mid-Atlantic Gas and Electric Utility. 2003.
93. Workshop on PBR (for Regulators) for a Southeast Electric Utility. 2003.
94. Strategic Advice for a Midwest Power Transmission Company. 2003.
95. PBR Research for a Canadian Gas Distributor. 2003.
96. Benchmarking Research and Testimony for a Canadian Gas Distributor. 2003-2004.
97. Consultation on Benchmarking and Productivity Issues for Two British Power Distributors. 2003.
98. Power Distribution Productivity and Benchmarking Research for a South American Regulator. 2003-2004.
99. Statistical Benchmarking of Power Transmission for a Japanese Research Institute. 2003-4.
100. Consultation on PBR for a Western Gas Distributor. 2003-4.
101. Research and Advice on PBR for Gas Distribution for a Western Gas Distributor. 2004.
102. PBR, Benchmarking and Productivity Research and Testimony for Two Western Energy Distributors. 2004.
103. Advice on Productivity for Two British Power Distributors. 2004.
104. Workshop on Service Quality Regulation for a Canadian Trade Association. 2004.
105. Strategic Advice for a Canadian Trade Association. 2004.
106. White Paper on Unbundled Storage and Local Gas Markets for a Midwestern Gas Distributor. 2004.
107. Statistical Benchmarking Research for a British Power Distributor. 2004.
108. Statistical Benchmarking Research for Three British Power Distributors. 2004.

109. Benchmarking Testimony for Three Ontario Power Distributors. 2004.
110. Indexation of O&M Expenses for an Australian Power Distributor. 2004.
111. Statistical Benchmarking of O&M Expenses for a Canadian Gas Distributor. 2004.
112. Benchmarking Testimony for a Canadian Power Distributor. 2005.
113. Statistical Benchmarking for a Canadian Power Distributor. 2005.
114. White Paper on Power Distribution Benchmarking for a Canadian Trade Association. 2005.
115. Statistical Benchmarking for a Southeast Bundled Power Utility. 2005.
116. Statistical Benchmarking of a Nuclear Power Plant and Testimony. 2005.
117. White Paper on Utility Rate Trends for a U.S. Trade Association. 2005.
118. TFP Research for a Northeast U.S. Power Distributor, 2005.
119. Seminars on PBR and Statistical Benchmarking for a Northeast Electric Utility, 2005.
120. Statistical Benchmarking and Testimony for a Northeast U.S. Power Distributor, 2005.
121. Testimony Transmission PBR for a Canadian Electric Utility, 2005.
122. TFP and Benchmarking Research and Testimony for Two California Energy Utilities. 2006.
123. White Paper on Power Transmission PBR for a Canadian Electric Utility. 2006.
124. Testimony on Statistical Benchmarking for a Canadian Electric Utility. 2006.
125. White Paper on PBR for Major Plant Additions for a U.S. Trade Association. 2006.
126. PBR Plan Design for a Canadian Regulatory Commission. 2006.
127. White Paper on Regulatory Benchmarking for a Canadian Trade Association. 2007.
128. Productivity Research and Testimony for a Northeastern Power Distributor. 2007.
129. Revenue Decoupling Research and Presentation for a Northeast Power Distributor. 2007.
130. Gas Utility Productivity Research and PBR Plan Design for a Canadian Regulator. 2007.
131. Productivity Research and PBR Plan Design for a Western Bundled Power Service Utility. 2007.
132. Statistical Benchmarking for a Canadian Energy Regulator. 2007.
133. Research and Testimony in Support of a Revenue Adjustment Mechanism for a Northeastern Power Utility. 2008.
134. Consultation on Alternative Regulation for a Midwestern Electric Utility. 2008.
135. Research and Draft Testimony in Support of a Revenue Decoupling Mechanism for a Large Midwestern Gas Utility. 2008.
136. White Paper: Use of Statistical Benchmarking in Regulation. 2005-2009.
137. Statistical Cost Benchmarking of Canadian Power Distributors. 2007-2009.
138. Research and Testimony on Revenue Decoupling for 3 US Electric Utilities. 2008-2009.
139. Benchmarking Research and Testimony for a Midwestern Electric Utility. 2009.
140. Consultation and Testimony on Revenue Decoupling for a New England DSM Advisory Council. 2009.
141. Research and Testimony on Forward Test Years and the cost performance of a Vertically Integrated Western Electric Utility. 2009.
142. White Paper for a National Trade Association on the Importance of Forward Test Years for U.S. Electric Utilities. 2009-2010.
143. Research and Testimony on Altreg for Western Gas and Electric Utilities Operating under Decoupling. 2009-2010.
144. Research and Report on PBR Designed to Incent Long Term Performance Gains. 2009-2010.
145. Research and Report on Revenue Decoupling for Ontario Gas and Electric Utilities. 2009-2010.
146. Research and Testimony on the Performance of a Western Electric Utility. 2009-2010.
147. Research on Decoupling for a Western Gas Distributor. 2009-2010.
148. Research on Alternative Regulation Precedents for a Midwestern Electric Utility. 2010.
149. Research on Revenue Decoupling for a Northwestern Gas & Electric Utility. 2010.
150. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2010.

151. Research and Testimony on Forward Test Years and the cost performance of a large Western Gas Distributor. 2010-2011.
152. Research and Testimony in Support of Revenue Decoupling for a Midwestern Power Distributor. 2010-2011.
153. Benchmarking Research and Report on the Generation Maintenance Performance of a Midwestern Electric Utility. 2010-2011.
154. Research and Testimony on the Design of an Incentivized Formula Rate for a Canadian Gas Distributor. 2010-2011.
155. White Paper for a National Trade Association on Remedies for Regulatory Lag. 2010-2011.
156. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2011.
157. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor. 2011.
158. Research and Testimony on Remedies for Regulatory Lag for Three Northeastern Power Distributors. 2011-2012.
159. Research and Testimony on the Design of Performance Based Ratemaking Mechanisms for a Canadian Consumer Group. 2011-2012.
160. Research and Testimony on Projected Attrition for a Northwest Electric Utility. 2011-2012.
161. Research and Testimony on the Design of a Performance Based Ratemaking Plan for a Canadian Gas Utility. 2012-2013.
162. Testimony for US Coal Shippers on the Treatment of Cross Traffic in US Surface Transportation Board Stand Alone Cost Tests. 2012.
163. Survey of Gas and Electric Altreg Precedents for a US Trade Association. 2012-2013.
164. Research and Testimony on the Design of an Attrition Relief Mechanism for a Northeast Electric Utility. 2013.
165. Research and Testimony on Issues in PBR Plan Implementation for a Canadian Consumer Group. 2013.
166. Consultation on an Altreg Strategy for a Southeast Electric Utility. 2013.
167. Consultation on an Altreg Strategy for a Midwestern Electric Utility. 2013.
168. Research and Testimony on the Design of a PBR Plan for a Northeast Electric Utility. 2013.
169. Research and Testimony on the Design of a PBR Plan for a Massachusetts Electric Utility. 2013
170. Consultation on Altreg Strategy for a California Electric Utility. 2013.
171. Research on Drivers of O&M expenses for a Canadian Gas Utility. 2013.
172. Research on the Design of an Attrition Relief Mechanism for a Midwest Electric & Gas Distributor. 2013.
173. PBR Strategy for a Southeast Electric Utility. 2013
174. Research on the Design of an Attrition Relief Mechanism for a Southeast Electric Utility. 2013.
175. Research and Testimony on Productivity Trends of Gas and Electric Power Distributors for a Canadian Consumer Group, 2013-2014.
176. Research and Testimony on Productivity Trends of Vertically Integrated Electric Utilities, 2014.
177. Research and Testimony on Statistical Benchmarking and O&M Expense Escalation for a Western Electric Utility, 2014.
178. Transnational Benchmarking of Power Distributor O&M Expenses for an Australian Regulator, 2014.
179. Research and Testimony on Statistical Benchmarking and O&M Cost Escalation for an Ontario Power Distributor, 2014-2015.
180. Assessment of Statistical Benchmarking for Australian Power Distributors, 2014-2015.
181. Research and Testimony on Merger of Two Midwestern Utility Holding Companies, 2014-2015.
182. White Paper on PBR for a Midwest Electric Utility, 2015.
183. Research and Support in the Development of Regulatory Frameworks for the Utility of the Future, 2015.
184. Survey of Gas and Electric Alternative Regulation Precedents. 2015.

185. White Paper on Multiyear Rate Plans for US Electric Utilities, 2015.
186. White Paper on Performance-Based Regulation in a High Distributed Energy Resources Future, 2016.
187. White Paper on Performance Metrics for the Utility of the Future for a US Trade Association and a consortium of electric utilities, 2016.
188. Research and Testimony on PBR for Power Transmission and Distribution.
189. Testimony on Revenue Decoupling for Pennsylvania Energy Distributors, 2016.
190. Research and Testimony on PBR Plan Design and US Power Distribution Productivity Trends, 2016.
191. Development of a Revenue Decoupling Mechanism and Supporting Testimony on behalf of a Midwest Environmental Advocate, 2016.
192. Research and Testimony on Total Factor Productivity of Hydroelectric Generators for a Canadian Regulator. 2016.
193. White Paper on Utility Experience and Lessons Learned from Performance-Based Regulation Plans, 2016-2017.

## Publications


1. Public vs. Private Management of Mineral Inventories: A Statement of the Issues. Earth and Mineral Sciences 53, (3) Spring 1984.
2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November, 1987.
7. Storage, Monopoly Power, and Sticky Prices. les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. Materials and Society 12 (1) 1988.
9. Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), Energy Journal 8 (3) 1988.
10. A Competitive Model of Primary Sector Storage of Refined Oil Products. July 1987, Resources and Energy 10 (2) 1988.
11. Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil. Energy Economics 10 (4) 1988.
12. Speculative Stocks and Working Stocks. Economic Letters 28 1988.
13. Theory of Pricing and Storage of Field Crops With an Application to Soybeans [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. Competitive Speculative Storage and the Cost of Petroleum Supply. The Energy Journal 10 (1) 1989.
15. Evaluating Alternative Measures of Credited Load Relief: Results From a Recent Study For New England Electric. In Demand Side Management: Partnerships in Planning for the Next Decade (Palo Alto: Electric Power Research Institute, 1991).

16. Futures Prices and Hidden Stocks of Refined Oil Products. In O. Guvanen, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.
18. Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).
19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.
23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.
29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
34. "Econometric Cost Benchmarking of Power Distribution Cost" (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
35. "Assessing Rate Trends of U.S. Electric Utilities", Edison Electric Institute, January 2006.
36. "Alternative Regulation for North American Electric Utilities" (With Lawrence Kaufmann), Electricity Journal, July 2006.
37. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
38. "Alternative Regulation for Infrastructure Cost Recovery", Edison Electric Institute, January 2007.
39. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde, and Steve Fenrick), Natural Gas and Electricity, 2008.
40. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009

41. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, 2009.
42. "Alternative Regulation, Benchmarking, and Efficient Diversification", USAEE Dialogue, August 2009.
43. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), in Lester C. Hunt and Joanne Evans, eds., International Handbook on the Economics of Energy, 2009.
44. "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" (With Lullit Getachew), Review of Network Economics, December 2009
45. "Forward Test Years for US Electric Utilities" (With David Hovde, Lullit Getachew, and Matt Makos), Edison Electric Institute, August 2010.
46. "Innovative Regulation: A Survey of Remedies for Regulatory Lag" (With Matt Makos and Gentry Johnson), Edison Electric Institute, April 2011.
47. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, 2013.
48. "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, November 2015.
49. "Performance-Based Regulation in a High Distributed Energy Resources Future," (With Tim Woolf, Synapse Energy Economics), Lawrence Berkeley National Laboratory, January 2016.

## Conference Presentations

1. American Institute of Mining Engineering, New Orleans, LA, March 1986
2. International Association of Energy Economists, Calgary, AL, July 1987
3. American Agricultural Economics Association, Knoxville, TN, August 1988
4. Association d'Econometrie Appliqué, Washington, DC, October 1988
5. Electric Council of New England, Boston, MA, November 1989
6. Electric Power Research Institute, Milwaukee, WI, May 1990
7. New York State Energy Office, Saratoga Springs, NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus, OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg, VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell, MT, May 1994
12. Edison Electric Institute, Washington, DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando, FL, March 1995
14. Illinois Commerce Commission, St. Charles, IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco, CA, April 1996
18. AIC Conferences, Orlando, FL, April 1996
19. IBC Conferences, San Antonio, TX, June 1996
20. American Gas Association, Arlington, VA, July 1996
21. IBC Conferences, Washington, DC, October 1996
22. Center for Regulatory Studies, Springfield, IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton, AL, July 1997

26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving, TX, Sept. 1997
27. American Gas Association, Washington, DC [national telecast], September 1997
28. Infocast, Miami Beach, FL, Oct. 1997
29. Edison Electric Institute, Arlington, VA, March 1998
30. Electric Utility Consultants, Denver, CO, April 1998
31. University of Indiana, Indianapolis, IN, August 1998
32. Edison Electric Institute, Newport, RI, September 1998
33. University of Southern California, Los Angeles, CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio, TX, April 2000
38. Infocast, Chicago, IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster, MA, July 2000
41. Infocast, Washington, DC, October 2000
42. Wisconsin Public Utility Institute, Madison, WI, November 2000
43. Infocast, Boston, MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa, FL, August 2001
45. Infocast, Washington, DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto, ON, March 2002
47. Canadian Electricity Association, Whistler, BC, May 2002
48. Canadian Electricity Association, Montreal, PQ, September 2002
49. Ontario Energy Association, Toronto, ON, November 2002
50. Canadian Gas Association, Toronto, ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge, LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax, NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto, ON, June 2006
59. Edison Electric Institute, Madison WI, August 2006
60. EUCI, Arlington VA, September 2006 [Conference chair]
61. EUCI, Arlington, VA September 2006
62. Law Seminars, Las Vegas, February 2007
63. Edison Electric Institute, Madison WI, August 2007
64. Edison Electric Institute, national eforum, 2007
65. EUCI, Seattle, WA, 2007 [Conference chair]
66. Massachusetts Energy Distribution Companies, Waltham MA, July 2007.
67. Edison Electric Institute, Madison WI, July-August 2007.
68. Institute of Public Utilities, Lansing MI, 2007
69. EUCI, Denver, 2008 [Conference chair]
70. EUCI, Chicago, July 2008 [Conference chair]
71. EUCI, Toronto, March 2008 [Conference chair]
72. Edison Electric Institute, Madison WI, August 2008
73. EUCI, Cambridge MA, March 2009 [Conference chair]

74. Edison Electric Institute, national eforum, May 2009
75. Edison Electric Institute, Madison WI, July 2009
76. EUCI, Cambridge MA, March 2010 [Conference chair]
77. Edison Electric Institute, Madison WI, July 2010
78. EUCI, Toronto, November 2010 [Conference chair]
79. Edison Electric Institute, Madison WI, July 2011
80. EUCI, Philadelphia PA, November 2011 [Conference chair]
81. SURFA, Washington DC, April 2012
82. Edison Electric Institute, Madison WI, July 2012
83. EUCI, Chicago, IL, November 2012 [Conference chair]
84. Law Seminars, Las Vegas, NV, March 2013
85. Edison Electric Institute, Washington DC, April 2013
86. Edison Electric Institute, Washington DC, May 2013
87. Edison Electric Institute, Madison WI, July 2013
88. National Regulatory Research Institute, Teleseminar, August 2013
89. EUCI, Chicago, IL April 2014 [Conference chair]
90. Edison Electric Institute, Madison WI, July 2014
91. Financial Research Institute, Columbia MO, September 2014
92. Great Plains Institute, St. Paul MN, September 2014
93. Law Seminars, Las Vegas, NV, March 2015
94. Edison Electric Institute, Madison WI, July 2015
95. Great Plains Institute, Minneapolis, MN, February 2016
96. Wisconsin Public Service Commission, Madison WI, March 2016
97. Society of Utility Regulatory Financial Analysts (SURFA), Indianapolis, IN, April 2016
98. Edison Electric Institute, Madison WI, August 2016

## Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

## Association Memberships (active)

International Association of Energy Economists
Wisconsin Public Utilities Institute

# KAJA REBANE

JUNE 2016

**Address:** Pacific Economics Group Research LLC
44 East Mifflin Street, Suite 601
Madison, WI 53703
(608) 257-1522
krebane@pacificeconomicsgroup.com

**Education:**

**Current:** PhD: Environment & Resources
University of Wisconsin-Madison

**Past:** MA: Agricultural & Applied Economics
University of Wisconsin-Madison
May 2013

MS: Land Resources
University of Wisconsin-Madison
May 2010

Graduate Certificate: Energy Analysis & Policy
University of Wisconsin-Madison
May 2010

BS (with Honors): Biology
Stanford University
June 2002

**Relevant Work Experience:**

August 2012-present: Economist II
Pacific Economics Group Research
Madison, WI

Conduct empirical research and policy analysis related to the regulation of electric and gas utilities. Focal areas include statistical and econometric evaluation of cost and reliability performance, revenue decoupling, performance incentive mechanisms, and regulatory reforms to encourage utility accommodation of distributed energy resources.

July 2009-June 2012: Project Assistant
Department of Agricultural & Applied Economics
University of Wisconsin-Madison

Evaluated outcomes of entrepreneurship-related programs on behalf of the Kauffman Foundation. Duties included the gathering of data, preparation of case studies, and collaboration with campus stakeholders.

February 2007-May 2009: Project Assistant
Nelson Institute for Environmental Studies
University of Wisconsin-Madison

Assisted in establishing a graduate certificate in Business, Environment and Social Responsibility, supported the foundation of the Wisconsin Initiative on Climate Change Impacts, helped develop an Engineering Professional Development online sustainability curriculum, assisted in construction of a campus sustainability web portal, and provided research and project support.

January 2008-May 2008: Teaching Assistant (People, Planet, Profit)
School of Business
University of Wisconsin-Madison

Co-delivered a new course on use of the triple bottom line concept in business. Duties included curriculum development, grading and student support.

September 2006-December 2006: Teaching Assistant (Ecology, Evolution and Genetics)
Biology Core Curriculum
University of Wisconsin-Madison

Provided teaching support for an introductory course in the biological sciences. Ran discussion sections, responded to student questions, and graded assignments and exams.

September 2005-December 2005: Teaching Assistant (Renewable Energy Technology)
Department of Biological Systems Engineering
University of Wisconsin-Madison

Developed and delivered lectures, recorded and edited lecture videos, graded assignments and exams, and provided general support for a new course on renewable energy systems.

**Publications:**

Rebane, K. L, & Goldrick-Rab, S. (2012). Collecting detailed expenditure information from undergraduates: Lessons learned and recommendations for future efforts. Working Paper, Wisconsin Scholars Longitudinal Study.

Rebane, K. L., & Barham, B. L. (2011). Knowledge and adoption of solar home systems in rural Nicaragua. *Energy Policy*, *39*(6), 3064-3075.

PEG Research Projects:

1. Revenue Decoupling of a Vertically Integrated US Utility (2016): Researched Minnesota's regulatory background and constructed a revenue decoupling mechanism simulation. Work performed on behalf of an environmental intervenor.

2. Performance-based regulation of power and gas distributors in Alberta (2016): Researched Alberta's regulatory background, gathered data for use in productivity analyses, and constructed customer growth forecasts. Work performed on behalf of a Canadian consumer group.

3. Multiyear rate plans for distribution and transmission utilities in Québec (2015-2016): Researched Québec's regulatory policy framework, gathered data related to transmission and distribution productivity, and simulated a revenue cap for a Canadian electric utility based on a Kahn X factor methodology. Work performed for a Canadian consumers' association.

4. Implications of alternative regulation for demand-side management in Pennsylvania (2016): Helped draft testimony on the implications of revenue decoupling, performance incentive mechanisms, multiyear rate plans, and other aspects of alternative regulation for demand-side management in Pennsylvania. Work conducted on behalf of an environmental intervenor.

5. Performance metrics for the utility of the future (2016): Helped draft white paper on performance metrics for the utility of the future. Researched the regulatory history of metrics used in incentive regulation, and evaluated the implications of different approaches for addressing emerging challenges. Work performed for a US trade association and a consortium of electric utilities.

6. Midwestern US electric company merger implications (2015): Researched potential implications of proposed merger for customer choice and market power. Work performed on behalf of a municipal electric utility.

7. Development of alternative US/Ontario benchmarking model (2014-2015): Replicated benchmarking results submitted by a distribution company, and developed an alternative transnational benchmarking model. Work conducted for a Canadian regulator.

8. Australian/US database construction and benchmarking (2014): Collaborated on constructing transnational database of electric distribution company data, and performed econometric benchmarking analyses for demonstration purposes. Work performed for an Australian regulator.

9. Productivity of vertically integrated US electric utilities (2013-2014): Assisted in a productivity analysis of a large sample of vertically integrated US electricity companies, and of a more limited peer group on behalf of an electric utility.

10. Evaluation of company-sponsored productivity evidence in British Columbia (2013): Analyzed productivity evidence supplied by companies on behalf of a Canadian consumers' association.

11. Reliability benchmarking of Ontario electric utilities (2013): Conducted econometric modeling of the reliability performance of Ontario electric utilities.

12. O&M productivity and return on investment of Alberta gas and electric distributors (2013): Assisted in O&M partial factor productivity analysis of Alberta gas and electric distributors, and implemented econometric models of the impact of regulatory systems on the return on investment for US electric utilities. Work done on behalf of a Canadian consumers' group.

13. Productivity of Northeast US power distributors (2013): Assisted in research measuring the productivity of power distributors on behalf of a northeast electric utility.

14. Power distribution productivity and cost benchmarking (2012-2013): Assisted in analyzing the productivity and cost of power distributors on behalf of a Canadian regulator.

# Incentivizing Efficient DERs for Otter Tail Power

Mark Newton Lowry, PhD
President

Kaja Rebane
Economist II

16 August 2016

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin, Suite 601
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

# Table of Contents

# 1. Introduction

Distributed energy resources ("DERs") in the form of demand-side management ("DSM") and distributed generation and storage ("DGS") are transforming America's electric power industry.[1] DSM is the cheapest and cleanest way to meet America's energy needs. There is enormous potential to save money, create local jobs, and reduce environmental damage by making use of the grid less peaked and reducing the volumes of energy needed by buildings, processes, and energy-using equipment. DGS is an increasingly attractive alternative to grid-supplied power. Minnesota's energy utilities are strategically placed to facilitate DERs, but reforms in the existing regulatory system are needed for utilities to fully embrace their potential.

Otter Tail Power ("OTP" or "the Company") filed a general rate case with Minnesota's Public Utilities Commission ("MNPUC" or "the Commission") in February. The Company, near the midpoint of a period of high capital expenditures ("capex"), has asked for a sizable rate increase and a redesign of rates for small-volume customers that lowers their volumetric charges relative to their fixed charges. The revised rates are touted as helping customers make better DER choices.

Pacific Economics Group ("PEG") Research LLC is a leading provider of research and testimony on revenue decoupling, performance-based regulation, and other alternatives to traditional cost of service regulation, which are sometimes referred to jointly as "alternative regulation" ("Altreg"). Work for diverse clients that include utilities, regulators, and environmental groups in the United States, Canada, and countries overseas has given us a reputation for objectivity and dedication to good regulation. We have been retained by Fresh Energy to discuss revenue decoupling and other ways to strengthen Otter Tail's incentives to embrace efficient DERs.

To evaluate the likely impact of revenue decoupling on DER outcomes, an understanding of the implicit disincentives for utilities to embrace DERs which are created by

[1] DSM is here defined to include both conservation and demand response programs.

traditional regulation is needed. Revenue decoupling is an effective way to remove some of these disincentives, but by itself cannot address them all. It is thus desirable to consider revenue decoupling alongside other regulatory tools that can work together synergistically to achieve the desired effects. To assist the Commission in its deliberations, we therefore place revenue decoupling in a broader regulatory context.

The plan for the paper is as follows. In Section 2, we discuss ways in which traditional regulation discourages efficient DERs and consider how Altreg reforms can provide more encouragement. There follow in Sections 3-7 consideration of five Altreg tools that have been touted for their ability to encourage DERs.

- Revenue decoupling
- Tracking of DSM expenses
- DSM performance incentive mechanisms
- Multiyear rate plans
- Fixed/variable rate designs

We then discuss the situation of Otter Tail and prescribe an Altreg solution.

# 2. Traditional Regulation and the Need for Altreg

## 2.1. Traditional Regulation

The traditional US approach to regulating retail rates of energy utilities developed over many decades. In this system, called "cost-of-service" regulation ("COSR"), a utility's rates are designed to recover its cost of providing service. The chief means of resetting rates is the general rate case. In these litigated proceedings, a revenue requirement is established that reflects the normalized and prudent cost of service in a test year. The Federal Energy Regulatory Commission ("FERC") often uses a substantially different system to regulate interstate power transmission that involves formula rate plans (a kind of broad-based cost tracker).

The revenue requirement is allocated across the utility's services. Rates are then designed to recover the revenue requirement for each service given assumptions about billing determinants (e.g., energy consumption and peak demand). Most revenue is drawn from volumetric and other usage charges, so called because they vary with a customer's use of the system. The balance of revenue is typically drawn from fixed charges such as customer charges.

To address changes in some costs more promptly than is possible through rate cases, regulators often use cost trackers and associated rate riders. Large, volatile costs like those for fuel and purchased power are typically recovered using cost trackers. The components of rates that address costs of non-energy inputs such as capital, labor, and materials are sometimes called base rates.[2] Costs that cause overall cost to grow rapidly are increasingly subject to tracker treatment today and include costs of certain capital expenditures.

Utilities file rate cases when revenue is, in the absence of higher rates, expected to fall short of the cost of service, resulting in financial attrition. The timing of these cases is irregular and depends on business conditions. For example, rate cases tend to be more frequent when inflation is rapid or when high capex is needed which does not automatically trigger new revenue.

Trends in the demand for utility services are also important drivers of attrition and rate case filings. Under traditional rate designs, growth in base rate revenue is chiefly driven by growth in system use. Meanwhile, cost is largely fixed in the short run with respect to system use but grows with customer connections and other dimensions of system capacity. The difference between the growth of system use and capacity is thus an important determinant of rate case frequency. Since the capacity growth of utilities is highly correlated with growth in the number of customers they serve, this difference is often approximated by the trends in use per customer (aka “average use”).

Historical trends in the average use of electricity by residential and commercial (“R&C”) customers of US electric utilities are detailed in Table 1. It can be seen that the average use of these customers grew rapidly for decades until the 1970s. During this period, high usage charges benefitted electric utilities and helped revenue track cost growth so that frequent rate cases were unnecessary.

[2] Utilities vary in the precise rates that they label "base" rates.

Table 1

Trends in Average Deliveries of Electricity to

US Residential and Commercial Customers

| | Residential | | Commercial | |
|---|---|---|---|---|
| | Level | Growth Rate | Level | Growth Rate |
| **Multiyear Averages** | | | | |
| 1926-1930 | 464 | 7.06% | 3,545 | 6.67% |
| 1931-1940 | 723 | 5.45% | 4,048 | 2.00% |
| 1941-1950 | 1,304 | 6.48% | 6,485 | 5.08% |
| 1951-1960 | 2,836 | 7.53% | 12,062 | 6.29% |
| 1961-1970 | 5,235 | 6.13% | 28,893 | 9.51% |
| 1971-1980 | 8,205 | 2.45% | 49,045 | 3.07% |
| 1981-1990 | 9,062 | 0.63% | 56,571 | 1.40% |
| 1991-2000 | 10,061 | 1.15% | 67,006 | 1.68% |
| 2001-2007 | 10,941 | 0.73% | 74,224 | 0.64% |
| 2008-2014 | 11,059 | -0.38% | 75,311 | -0.22% |

**Sources**: US Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and form EIA-0035, "Monthly Energy Review."

Growth in average use declined in the 1970s and was sluggish in the 1980-2007 period. This increased the frequency of rate cases. Since 2007, R&C average use trends of many electric utilities have been close to zero or negative. The effect of this development on the frequency of rate cases has been mitigated by slow input price inflation, but this tempering influence is offset when utilities have high levels of non-revenue producing capex. Declines in average use were, incidentally, chronic in the gas distribution industry for many years. This makes gas industry regulatory precedents increasingly relevant for electric utilities today.

## 2.2. The Need for Altreg

Traditional regulation has certain shortcomings that Altreg can address. For example, the frequent rate cases triggered by unfavorable business conditions raise regulatory cost and weaken utility performance incentives.[3] While a number of tools can be used to reduce the cost of traditional regulation, these can have undesirable side effects. For example, regulation

[3] Rate cases nonetheless have benefits, which include the opportunity to review utility operations and provide feedback.

can be simplified by tracking more costs or by de-emphasizing prudence reviews. However, these measures weaken utility cost-containment incentives.[4] Thus, the generally less favorable business conditions of utilities since the 1960s have tended to weaken their performance incentives.

Traditional regulation is also well known to discourage utilities from embracing efficient DERs. Utilities are incentivized to bolster average use, a phenomenon called the "throughput incentive." DERs slow growth in average use, thereby eroding margins. Utilities are more reluctant to implement time-sensitive base rates and other rate designs that encourage efficient DERs because of increased exposure to demand volatility and the unpredictability of the response to new rates. For example, utilities are unsure how customers will respond to high peak period charges in an era when the cost of distributed power storage is rapidly falling.

Another problem is the weak incentives utilities can have under traditional regulation to use DSM to contain costs. For environmental groups such as Fresh Energy, a special concern is the insensitivity of utility finances to the environmental impact of their operations. Utilities may also lack sufficient incentives to use DERs to contain their own load-related costs. Their load-related costs include those for fuel and purchased power, generation and transmission facilities, and distribution substations and transformers.

The frequent rate cases that can occur under COSR reduce utility incentives to slow load-related capex with DERs. For example, there is less benefit from using DERs to postpone distribution system upgrades to serve load growth. Reductions in load-related capex also reduce utility investment opportunities. In addition, some load-related costs, (e.g., those for fuel, purchased power, and transmission) which could be reduced by DERs are recovered through trackers or formula rates which weaken utility incentives to embrace them.[5] For example, DSM programs provide an opportunity for a distributor to reduce the cost of purchased energy, but the utility has little incentive to reduce energy costs if they are passed promptly through to customers in a tracker.

[4] Trackers can be designed to strengthen cost containment incentives but typically are not.
[5] Many utilities have formula rates (a form of broad-based cost tracker) for their transmission costs. Additionally, many have cost trackers to recover charges they pay for transmission services from retail customers.

We conclude that utilities under traditional regulation often have a material disincentive to embrace DERs, even when DERs meet customer needs at lower cost than traditional grid service. Active opposition to certain DERs by utilities may occur. In addition, utilities do not benefit financially from many social benefits of DERs, such as a lighter environmental footprint. The DER incentive problem is increasingly important in an era when competition from alternatives to grid service is mounting and utilities are under pressure to reduce their environmental impact. In addition to incentive problems, DERs can place stress on a traditional regulatory system. For example, slower growth in average use due to DER adoption can increase the frequency of rate cases.

### 2.3. Mandates Versus Incentives

Key aspects of utility behavior can and should be mandated. For example, regulators should play an active role in the design of rates to ensure that they send appropriate price signals to customers. Even where mandates are feasible, however, there are often benefits to complementing them with incentives that help align utility interests with the public interest. This decreases utility resistance to complying with mandates, and results in increased enthusiasm, creativity, and industry on the part of utilities in pursuing regulatory goals. The burden of regulatory oversight can be reduced.

### 2.4. Criteria for Evaluating Altreg Remedies

In this testimony we consider five Altreg tools that have been touted for their ability to encourage efficient DERs. Sensible criteria are needed to compare these options. Relevant criteria include the success of the approach in fostering efficient DERs, addressing any attrition that can result, and making regulation more efficient. Special features of the options should also be considered.

## 3. Revenue Decoupling

### 3.1. The Basic Idea

Revenue decoupling adjusts a utility's rates periodically to enable *actual* revenue to track *allowed* revenue more closely. Most revenue decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue, and adjusts rates to draw down these variances. Meanwhile, the RAM escalates allowed revenue to provide relief for growing cost pressures. These mechanisms thus address different sources of financial attrition that utilities can experience between rate cases. The RDM addresses *revenue*-related attrition, leaving the RAM to address *cost*-related attrition.

### Revenue Decoupling Mechanisms

An RDM makes regularly scheduled adjustments to rates via a true-up mechanism. Such mechanisms usually involve a balancing account in which past differences between actual and allowed revenue are entered. The accumulated net variance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. This is usually undertaken with respect to usage charges, a practice that favors low-usage customers. Rates rise when volumes are low but also fall when volumes are high.

RDMs can make true-ups annually or more frequently. The size of the rate adjustment permitted in a given year may be capped; this guards against rate shocks that engender customer dissatisfaction and opposition to decoupling. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from R&C customers are decoupled. These customers together account for a high share of a utility's base rate revenue, and are often the primary focus of DSM programs.

RDMs also vary in terms of the services and corresponding tariffs over which revenues are pooled for true-up purposes. In some plans all services are placed in the same group for the calculation of revenue variances and trueups. Other plans have multiple groups of services, sometimes called service "baskets", so that customers of services in each basket are insulated from revenue variances in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true-ups are sometimes allowed only for the difference between allowed revenue and the *weather-normalized* actual revenue. An RDM that addresses demand variances from *all* sources is called a "full" decoupling mechanism. With full decoupling, the utility receives no more and no less than its commission-approved revenue requirement. The complication of weather-normalizing usage data is avoided.

### Revenue Adjustment Mechanisms

If allowed revenue doesn't change over time under decoupling the utility will experience financial attrition, since cost tends to rise for various reasons that include input price inflation and demand growth. For this reason, most decoupling systems have a RAM. Utilities operating without RAMs in their decoupling systems often file frequent rate cases. When developing a decoupling system, the need for a RAM is thus less of an issue than its design.

Most RAMs escalate allowed revenue only for customer growth. This is sometimes accomplished by adjusting rates to hold revenue-per-customer constant. Customer growth is an important driver of cost in its own right, and it is highly correlated with other cost drivers such as peak demand. The number of retail customers has frequently been the most important scale variable in PEG's numerous econometric studies of electric utility cost.

Escalating revenue for customer growth reduces the need for rate cases but rarely eliminates it because cost has several other drivers. Some approved RAMs have been "broad based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can reduce the need for rate cases substantially and thereby provide the foundation for a multiyear rate plan.[6] Broad-based RAMs in the United States are most commonly designed using cost forecasts, but inflation and productivity indexing can also be used. The following simple revenue cap index formula is illustrative.

*growth Revenue = growth Inflation – X + growth Customers.*

Here X, called the "X factor," can reflect achievable productivity growth and any tendency of the chosen inflation measure not to reflect the input price inflation that utilities experience.

[6] These plans are discussed further below.

To illustrate, we have gathered data from the FERC and other publicly available sources on the trend in the cost of base-rate inputs of a sample of 42 vertically integrated electric utilities ("VIEUs") in the US. The sample period is 1997-2014. Costs considered in our study included most non-energy O&M expenses, amortization and depreciation expenses, taxes, and a pro-forma return on net plant value. The sample includes a mix of large and small utilities that together serve 34 states. Table 2 and Figure 1 provide results of this work.

The table and figure also show the trend in the gross domestic price index ("GDPPI") and in the number of retail customers served by the sampled utilities. The GDPPI is the federal government's featured index of inflation in the prices of final goods and services in the US economy. Final goods and services include consumer products, capital equipment, and exports. The GDPPI tends to grow more slowly than the economy's input prices due to the rapid productivity growth of the economy.

Inspecting the results of Table 2 it can be seen that, over the full sample period, the average annual growth rate of VIEU cost substantially exceeded the corresponding trends in the GDPPI and the number of customers served. In fact, the cost trend was nearly equal to the *sum* of the trends of the other two variables. Similar results obtain for energy distribution. When a RAM escalates allowed revenue only for customer growth, utilities therefore usually retain the freedom to file rate cases and occasionally do file. It follows that regulators can approve revenue-per-customer decoupling with little concern that it will produce overearning.

An illustrative revenue cap index is constructed in Table 2 using GDPPI as the inflation measure. X is set at the value needed for the formula to match the cost trend of the utilities in our sample.[7] This value is 0.14% for the full sample period. A RAM with a GDPPI – 0.14% + Customers formula would have exactly compensated utilities (on average) over the *full* sample period but would have materially undercompensated them (on average) over the more recent 2008-2014 period.

[7] This simple method for setting X factors is sometimes called the "Kahn method" since it was developed by noted regulatory economist Alfred Kahn.

## Table 2

## Trends in VIEU Cost, VIEU Customers and Inflation[8,9]

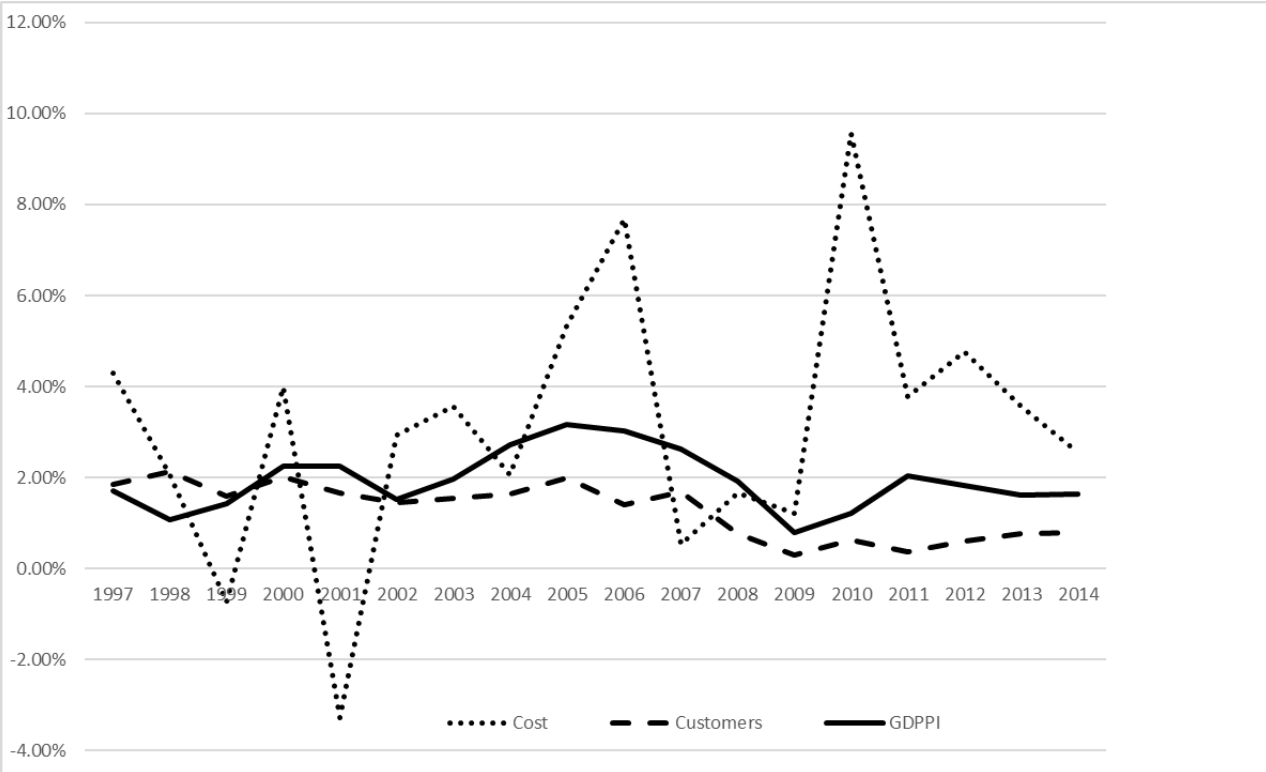
| | | | | Revenue Cap Index | |
|---|---|---|---|---|---|
| | Cost [%] [A] | Customers [%] [B] | GDPPI [%] [C] | Calculating an X Factor [D=(B+C)-A] | GDPPI-X + Customers [C-X+B] |
| | | | | | [X=0.14%] |
| 1997 | 4.30% | 1.86% | 1.71% | -0.73% | 3.43% |
| 1998 | 2.07% | 2.13% | 1.08% | 1.14% | 3.07% |
| 1999 | -0.73% | 1.58% | 1.42% | 3.73% | 2.87% |
| 2000 | 3.99% | 2.02% | 2.25% | 0.29% | 4.14% |
| 2001 | -3.28% | 1.67% | 2.25% | 7.20% | 3.78% |
| 2002 | 2.93% | 1.46% | 1.52% | 0.06% | 2.85% |
| 2003 | 3.57% | 1.55% | 1.97% | -0.05% | 3.39% |
| 2004 | 2.06% | 1.63% | 2.71% | 2.28% | 4.21% |
| 2005 | 5.34% | 1.99% | 3.17% | -0.19% | 5.02% |
| 2006 | 7.69% | 1.40% | 3.03% | -3.25% | 4.30% |
| 2007 | 0.53% | 1.69% | 2.63% | 3.80% | 4.19% |
| 2008 | 1.66% | 0.78% | 1.91% | 1.03% | 2.56% |
| 2009 | 1.21% | 0.29% | 0.79% | -0.13% | 0.94% |
| 2010 | 9.57% | 0.62% | 1.22% | -7.73% | 1.70% |
| 2011 | 3.77% | 0.37% | 2.04% | -1.36% | 2.28% |
| 2012 | 4.76% | 0.60% | 1.83% | -2.33% | 2.30% |
| 2013 | 3.57% | 0.76% | 1.62% | -1.19% | 2.24% |
| 2014 | 2.56% | 0.80% | 1.63% | -0.13% | 2.30% |
| **1997-2014** | 3.09% | 1.29% | 1.93% | 0.14% | 3.09% |
| **2008-2014** | 3.87% | 0.60% | 1.58% | -1.69% | 2.04% |

[8] Data Sources: FERC Form 1 (cost data), the Edison Electric Institute (allowed ROE), EIA Form 861 (customers), and the Bureau of Economic Analysis (GDPPI). Cost is calculated as reported O&M expenses less fuel, purchased power, transmission by others, miscellaneous power supply and transmission expenses, and customer service and information expenses plus an estimate of capital cost. O&M expenses considered include those for distribution, customer account, generation, and most transmission functions plus administrative and general cost. Capital cost was calculated as the product of rate base and a rate of return, plus depreciation and taxes.

[9] Growth rates are calculated logarithmically.

Figure 1

Trends in VIEU Cost, VIEU Customers, and Inflation




## 3.2. Decoupling Precedents

Revenue decoupling has been widely adopted in the United States and abroad. States that have tried gas and electric revenue decoupling are shown in Figures 2a and 2b, respectively. Table 3 details current revenue decoupling precedents in the US and Canada.

Inspecting the figures, it can be seen that decoupling is currently used to regulate at least one gas or electric utility in more than twenty-five US jurisdictions. Decoupling is particularly widespread in the gas distribution industry, where it is used in twenty-three jurisdictions. This reflects the fact that declining average use by residential and commercial customers has been chronic in that industry.

Figure 2a Electric Revenue Decoupling by State

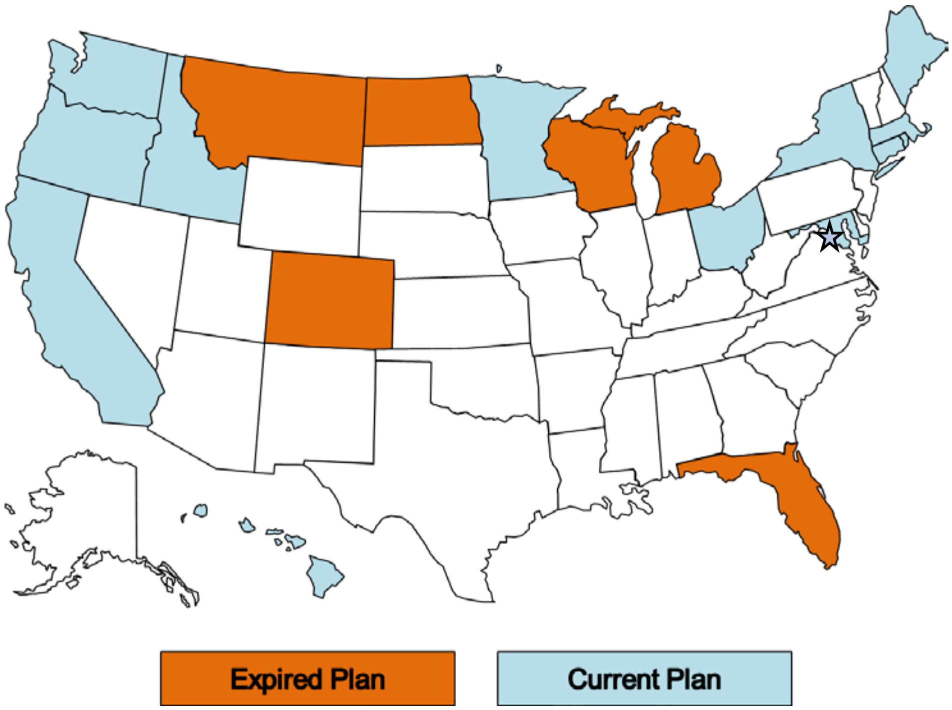



Figure 2b Gas Revenue Decoupling by State

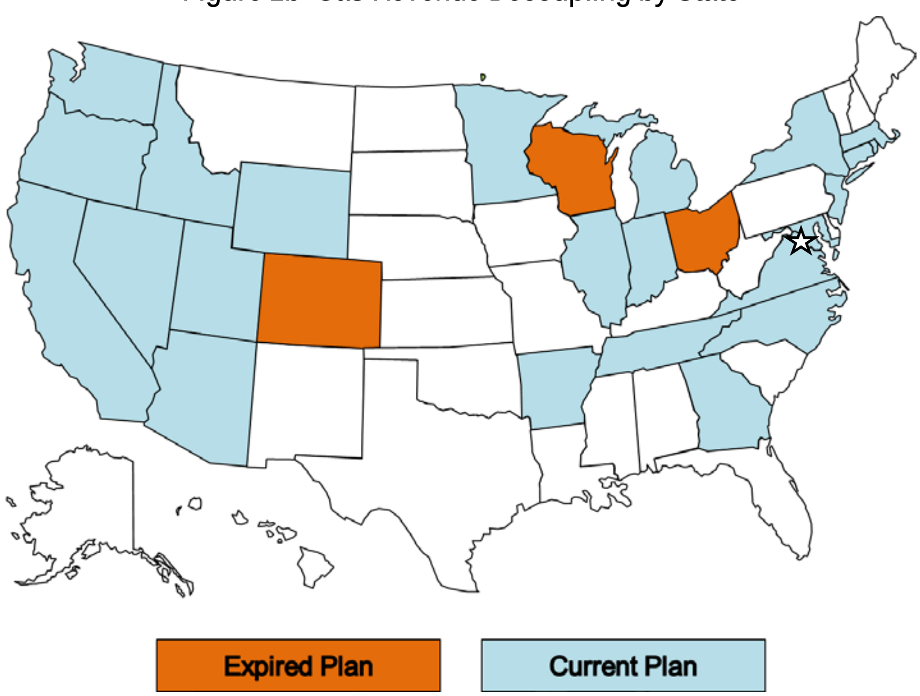


Table 3

# Current Revenue Decoupling Precedents

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| **United States** | | | | | |
| **AR** | Arkansas Oklahoma Gas | Gas | 2014-open | No RAM but multiple capital cost trackers | Docket 13-078-U |
| **AR** | CenterPoint Energy | Gas | 2008-2016 | No RAM but multiple capital cost trackers | Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF |
| **AR** | SourceGas Arkansas (Arkansas Western) | Gas | 2014-open | No RAM but multiple capital cost trackers | Docket 13-079-U |
| **AZ** | Southwest Gas | Gas | 2012-open | Customers | Docket G-01551A-10-0458 |
| **CA** | Bear Valley Electric Service | Electric | 2013-2017 | Stairstep through 2016, No RAM thereafter | Decision 14-11-002 |
| **CA** | California Pacific Electric | Electric | 2013-open | Indexing through 2015, No RAM thereafter | Decision 12-11-030 |
| **CA** | Pacific Gas & Electric | Gas & Electric | 2014-2016 | Stairstep | Decision 14-08-032 |
| **CA** | San Diego Gas & Electric | Gas & Electric | 2016-2018 | Stairstep | Decision 16-06-054 |
| **CA** | Southern California Edison | Electric | 2015-2017 | Hybrid | Decision 15-11-021 |
| **CA** | Southern California Gas | Gas | 2016-2018 | Stairstep | Decision 16-06-054 |
| **CA** | Southwest Gas | Gas | 2014-2018 | Stairstep | Decision 14-06-028 |
| **CT** | Connecticut Light & Power | Electric | 2014-open | No RAM | Docket 14-05-06 |
| **CT** | Connecticut Natural Gas | Gas | 2014-open | No RAM | Docket 13-06-08 |
| **CT** | United Illuminating | Electric | 2013-open | Stairstep until July 2015, No RAM thereafter | Docket 13-01-19 |
| **DC** | Potomac Electric Power | Electric | 2010-open | Customers | Order 15556 |
| **GA** | Atmos Energy | Gas | 2012-open | No RAM but FRP type mechanism also in effect | Docket 34734 |
| **HI** | Hawaiian Electric Company | Electric | 2011-open | Hybrid | Dockets 2008-0274, 2008-0083, 2013-0141 |
| **HI** | Hawaiian Electric Light Company | Electric | 2012-open | Hybrid | Dockets 2008-0274, 2009-0164, 2013-0141 |
| **HI** | Maui Electric | Electric | 2012-open | Hybrid | Dockets 2008-0274, 2009-0163, 2013-0141 |
| **ID** | Avista | Electric & Gas | 2016-2018 | Customers | Cases AVU-E-15-05, AVU-G-15-01 |
| **ID** | Idaho Power | Electric | 2012-open | Customers | Cases IPC-E-11-19, IPC-E-14-17 |
| **IL** | North Shore Gas | Gas | 2012-open | No RAM | Case 11-0280 |
| **IL** | Peoples Gas Light & Coke | Gas | 2012-open | No RAM but broad-based capital cost tracker | Case 11-0281 |
| **IL** | Ameren Illinois | Gas | 2016-open | No RAM but broad-based capital cost tracker | Case 15-0142 |
| **IN** | Citizens Gas | Gas | 2007-open | Customers | Cause 42767 |
| **IN** | Indiana Gas | Gas | 2016-2019 | Customers | Cause 44598 |
| **IN** | Indiana Natural Gas | Gas | 2014-open | Customers | Cause 44453 |
| **IN** | Vectren Southern Indiana | Gas | 2016-2019 | Customers | Cause 44598 |
| **MA** | Bay State Gas | Gas | 2015-2018 | Revenue per Customer Stairstep through 2016, RPC Freeze thereafter | DPU 15-50 |
| **MA** | Boston-Essex Gas | Gas | 2010-open | Customers | DPU 10-55 |
| **MA** | Colonial Gas | Gas | 2010-open | Customers | DPU 10-55 |
| **MA** | Fitchburg Gas & Electric | Gas | 2011-open | Customers | DPU 11-02 |
| **MA** | Fitchburg Gas & Electric | Electric | 2011-open | No RAM | DPU 11-01 |
| **MA** | Massachusetts Electric | Electric | 2010-open | No RAM but broad-based capital cost tracker | DPU 09-39 |
| **MA** | New England Gas | Gas | 2011-open | Customers | DPU 10-114 |
| **MA** | Nstar Gas | Gas | 2016-open | Customers | DPU 14-150 |
| **MA** | Western Massachusetts Electric | Electric | 2011-open | No RAM | DPU 10-70 |
| **MD** | Baltimore Gas & Electric | Electric | 2008-open | Customers | Letter Orders ML 108069, 108061 |
| **MD** | Baltimore Gas & Electric | Gas | 1998-open | Customers | Case 8780 |
| **MD** | Chesapeake Utilities | Gas | 2006-open | Customers | Order 81054 |
| **MD** | Columbia Gas of Maryland | Gas | 2013-open | Customers | Order 85858 |
| **MD** | Delmarva Power & Light | Electric | 2007-open | Customers | Order 81518 |
| **MD** | Potomac Electric Power | Electric | 2007-open | Customers | Order 81517 |
| **MD** | Washington Gas Light | Gas | 2005-open | Customers | Order 80130 |
| **ME** | Central Maine Power | Electric | 2014-open | Customers | Docket 2013-00168 |
| **MI** | Consumers Energy | Gas | 2015-open | No RAM | Case U-17643 |
| **MI** | Michigan Consolidated Gas | Gas | 2013-open | No RAM | Case U-16999 |

Table 3 (cont'd)

| Jurisdiction | Company Name | Services | Plan Years | Revenue Adjustment Mechanism | Case Reference |
|---|---|---|---|---|---|
| | | | **United States** (cont'd) | | |
| **MN** | CenterPoint Energy | Gas | 2015-2018 | Customers | GR-13-316 |
| **MN** | Minnesota Energy Resources | Gas | 2013-open | Customers | GR-10-977 |
| **MN** | Northern States Power - MN | Electric | 2016-2018 | Customers | GR-13-868 |
| **NC** | Piedmont Natural Gas | Gas | 2008-open | Customers | Docket G-9, Sub 550 |
| **NC** | Public Service Co of NC | Gas | 2008-open | Customers | Docket G-5, Sub 495 |
| **NJ** | New Jersey Natural Gas | Gas | 2014-open | Customers | Docket GR13030185 |
| **NJ** | South Jersey Gas | Gas | 2014-open | Customers | Docket GR13030185 |
| **NV** | Southwest Gas | Gas | 2009-open | Customers | D-09-04003 |
| **NY** | Central Hudson G&E | Gas & Electric | 2015-2018 | Revenue per Customer Stairstep for Gas, Stairstep for Electric | Cases 14-E-0318, 14-G-0319 |
| **NY** | Consolidated Edison | Gas | 2014-2016 | Revenue per Customer Stairstep | Case 13-G-0031 |
| **NY** | Consolidated Edison | Electric | 2014-2016 | Stairstep | Case 13-E-0030 |
| **NY** | Corning Natural Gas | Gas | 2015-2017 | Customers | Case 11-G-0280 |
| **NY** | Keyspan Energy Delivery - Long Island | Gas | 2010-open | Revenue per Customer Stairstep through 2012, Customers thereafter | Case 06-G-1186 |
| **NY** | Keyspan Energy Delivery New York | Gas | 2013-open | Revenue per Customer Stairstep through 2014, Customers thereafter | Case 12-G-0544 |
| **NY** | National Fuel Gas | Gas | 2013-2015 | Customers | Case 13-G-0136 |
| **NY** | New York State Electric & Gas | Gas | 2016-2019 | Revenue per Customer Stairstep | Case 15-E-0283 |
| **NY** | New York State Electric & Gas | Electric | 2016-2019 | Stairstep | Case 15-G-0184 |
| **NY** | Niagara Mohawk | Gas | 2013-2018 | Revenue per Customer Stairstep through 2016, Customers thereafter | Case 12-G-0202 |
| **NY** | Niagara Mohawk | Electric | 2013-2018 | Stairstep through 2016, No RAM thereafter | Case 12-E-0201 |
| **NY** | Orange & Rockland Utilities | Gas | 2015-2018 | Revenue per Customer Stairstep | Case 14-G-0494 |
| **NY** | Orange & Rockland Utilities | Electric | 2015-2017 | Stairstep | Case 14-E-0493 |
| **NY** | Rochester Gas & Electric | Gas | 2016-2019 | Revenue per Customer Stairstep | Case 15-E-0285 |
| **NY** | Rochester Gas & Electric | Electric | 2016-2019 | Stairstep | Case 15-G-0286 |
| **NY** | St. Lawrence Gas | Gas | 2010-open | Revenue per Customer Stairstep through 2012, Customers thereafter | Case 08-G-1392 |
| **OH** | AEP Ohio | Electric | 2012-2018 | Customers | Cases 11-351-EL-AIR, 13-2385-EL-SSO |
| **OH** | Duke Energy Ohio | Electric | 2015-open | Customers | Case 14-841-EL-SSO |
| **OR** | Avista | Gas | 2016-open | Customers | Order 16-076 |
| **OR** | Cascade Natural Gas | Gas | 2016-2019 | Customers | Order 15-412 |
| **OR** | Northwest Natural Gas | Gas | 2012-open | Customers | Order 12-408 |
| **OR** | Portland General Electric | Electric | 2014-2016 | Customers | Order 13-459 |
| **RI** | Narragansett Electric | Electric | 2012-open | No RAM but broad-based capital cost tracker | Docket 4206 |
| **RI** | Narragansett Electric | Gas | 2012-open | Customers | Docket 4206 |
| **TN** | Chattanooga Gas | Gas | 2013-open | Customers | Docket 09-0183 |
| **UT** | Questar Gas | Gas | 2010-open | Customers | Docket 09-057-16 |
| **VA** | Columbia Gas of Virginia | Gas | 2016-2018 | Customers | Case PUE-2015-00072 |
| **VA** | Virginia Natural Gas | Gas | 2016-2019 | Customers | Case PUE-2015-00129 |
| **VA** | Washington Gas Light | Gas | 2013-2016 | Customers | Case PUE-2012-00138 |
| **WA** | Avista | Gas & Electric | 2015-2019 | Customers | Dockets UE-140188 and UG-140189 |
| **WA** | Cascade Natural Gas | Gas | 2016-open | Customers | Docket UG-152286 |
| **WA** | Puget Sound Energy | Gas & Electric | 2013-2016 | Revenue per Customer Stairstep | Dockets UE-121697 and UG-121705 |
| **WY** | Questar Gas | Gas | 2012-open | Customers | Docket 30010-113-GR-11 |
| **WY** | SourceGas Distribution | Gas | 2011-open | Customers | Docket 30022-148-GR-10 |
| | | | **Canada** | | |
| **BC** | BC Hydro | Electric | 2015-2016 | Stairstep | Order G-48-14 |
| **BC** | FortisBC | Electric | 2014-2019 | Indexing | Order G-139-14 |
| **BC** | FortisBC Energy | Gas | 2014-2019 | Indexing | Order G-138-14 |
| **BC** | Pacific Northern Gas | Gas | 2003-open | Customers | N/A |
| **ON** | Enbridge Gas Distribution | Gas | 2014-2018 | Stairstep | EB-2012-0459 |
| **ON** | Union Gas | Gas | 2014-2018 | Indexing | EB-2013-0202 |

In the electric utility industry, decoupling is currently used in fourteen jurisdictions. It has been particularly favored in states that strongly support DSM. The use of decoupling for electric utilities is growing, with recent approvals in Maine, Minnesota, and Washington state.

Minnesota's PUC has approved revenue decoupling for electric services of Xcel Energy and for two gas distributors (CenterPoint Energy and Minnesota Energy Resources Corporation). In approving decoupling for Xcel Energy, the Commission stated that "revenue decoupling has substantial potential to align the Company's interests with the public's interest in conservation and energy efficiency."[10] The approved decoupling system for Xcel Energy has the following provisions.

- Decoupling applies to residential service with space heating, residential service without space heating, and small general service (non-demand). Each service has its own basket.
- Revenue per customer is decoupled, so that revenue requirements rise gradually with growth in the number of customers.
- There is a soft cap on upward RDM rate adjustments equal to 3% of the service group's revenues, excluding revenues from the fuel clause and other riders. Where the cap is exceeded, eligibility for additional revenue in future periods is contingent on a showing that "demand-side management programs and other company initiatives were a substantial contributing factor to the declining energy sales triggering the rate adjustment, and that other non-conservation factors were not the primary factors for the declining sales."[11]
- Each RDM otherwise achieves *full* decoupling and makes adjustments only to *usage* charges.
- Xcel must file a plan to implement an education and outreach program to customers explaining the goals and operations of its RDM program.

In several jurisdictions utilities are *required* to operate under revenue decoupling by legislation or commission policy. California's return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk

[10] MNPUC, Docket No. E-002/GR-13-868, Order (May 8, 2015), p. 73.
[11] ibid, p. 73.

in the midst of the state's bulk power market crisis.[12] More recent legislation in Rhode Island required use of revenue decoupling for the state's gas and electric utilities. Commission policies mandating the use of revenue decoupling mechanisms have been adopted in Massachusetts and New York.

Revenue decoupling appears to have played a role in motivating utilities to embrace DERs. For example, in its most recent State Scorecard, the American Council for an Energy Efficient Economy ("ACEEE") reports net incremental savings from electricity efficiency programs as a share of 2014 retail sales.[13] Setting aside the states in which DSM programs are mainly administered by third parties, 7 of the 12 top-performing states employed electric decoupling in that year.[14] Among the remaining 29 states, only one had decoupling.

## 3.3. Decoupling Advantages

The numerous advantages of revenue decoupling have prompted Fresh Energy to strongly advocate its use in Minnesota regulation. We discuss here some of decoupling's salient advantages.

### Throughput Incentive

Decoupling can reduce or eliminate a utility's throughput-related disincentive for the full array of actions it can take to facilitate DERs. A soft cap on decoupling adjustments is more effective in addressing the throughput incentive than a hard cap, since it assures the utility that variances between expected and actual revenues will eventually be addressed. Under decoupling, revenue is insensitive to a 1% drop in volume growth whether it results from a conventional utility conservation program, less conventional market transformation initiatives, or increased DGS penetration.

[12] See California Public Utilities Code, Division 1, Part 1, Chapter 4, Article 2, Section 739.10 as amended by Assembly Bill X1 29 (Kehoe). It provides that "The commission shall ensure that errors in estimates of demand elasticity or sales not result in material over or undercollections of the electrical corporations."

[13] See American Council for an Energy-Efficient Economy, *The 2015 State Energy Efficiency Scorecards*, Report U1509, October 2015. In cases where 2014 data were unavailable, the ACEEE utilized 2013 data instead. This is the latest ACEEE report on this topic.

[14] Third parties, rather than utilities, are primarily responsible for DSM program administration in Delaware, Hawaii, Maine, New Jersey, New York, Oregon, Vermont and Wisconsin, as well as in Washington DC.

The size of the benefit from eliminating the throughput incentive depends on the role utilities play in DSM promotion. If DSM programs are undertaken by independent agencies rather than by utilities, the impact of decoupling on DSM outcomes is lessened. However, utilities have many other ways to influence DSM, including rate design and their support for large DSM budgets and tighter appliance efficiency standards and building codes. One indication of the importance of these other activities is that decoupling has been used in several jurisdictions (e.g., Hawaii, Maine, New Jersey, New York, Oregon, Washington DC, and Wisconsin) in which a sizable portion of DSM programs is not administered by utilities. Decoupling encourages utilities to work more closely with third party administrators. Utilities also have a great deal of influence on policies that affect DGS penetration.

One sign of the contribution decoupling makes to wide-ranging efforts to foster DSM is the commitments some utilities have made to unconventional DSM initiatives as a condition for gaining decoupling plan approval.

- In a decoupling settlement with Wisconsin's Citizens Utility Board, Wisconsin Public Service agreed to specific steps to support the adoption and implementation of certain recommendations of the Governor's Global Warming Task Force. These addressed residential and commercial energy efficient building codes, state appliance efficiency standards, and non-regulated fuels efficiency and conservation.
- The Hawaii Clean Energy Initiative Agreement involved the three Hawaiian Electric companies, the state of Hawaii, and its Division of Consumer Advocacy.[15] The agreement contained commitments in more than thirty areas.

In addition, in an order approving a decoupling plan for United Illuminating ("UI"), the Connecticut Department of Public Utility Control stated that it was approving the plan *not* because of its effect on the company's DSM program itself, but for its effect on "areas where UI does not already receive incentives."[16] The Department goes on to explain that

[15] "Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies," 2008.
[16] Connecticut DPUC, Decision in Docket 08-07-04, February 2009, p. 121.

> UI is still viewed as *the* energy provider by the general body of ratepayers. The Department believes that this will not change… Success in achieving Connecticut's energy policy goals requires that the Department take advantage of this relationship to promote the energy-related programs and policies that have been recently set in place.[17]

## Rate Design

Another benefit of decoupling is its ability to dovetail with rate designs that encourage efficient DERs. Decoupling imposes no restrictions on the rate designs themselves. Additionally, decoupling can reduce or eliminate the risk of revenue requirement recovery that may result from innovative rate designs that encourage efficient DERs. The maximum reduction in the risk of these rates is achieved when revenue is decoupled from *all* sources of demand volatility, including the business cycle and weather. This benefit of *full* decoupling is not widely recognized.

Some regulators have rejected proposals by utilities operating under decoupling for changes in rate designs intended to achieve goals that decoupling already accomplishes. For example, CenterPoint Energy Minnesota Gas has operated for several years under revenue decoupling. In a recent rate case, the Commission rejected CenterPoint's proposal to raise customer charges, stating that

> Increasing CenterPoint's customer charges would place too little emphasis on the need to set rates to encourage conservation. This is particularly true since the Company has a full-decoupling mechanism… decoupling already guarantees that CenterPoint will not fail to recover its revenue requirement due to lower-than-predicted sales.
>
> Furthermore, a major goal of revenue decoupling is to align a utility's interests with the public's interest in energy efficiency. Increasing the customer charge undermines this goal by incrementally reducing customers' incentive to conserve energy since, with a higher customer charge and relatively lower volumetric charge, they are less able to control the size of their bills by using less energy. Keeping CenterPoint's customer charges at current levels will maintain the existing incentive to conserve without affecting the Company's revenue stability.[18]

[17] *Ibid*, pp. 121-122.
[18] MNPUC, G-008/GR-15-424, June 2016, pp. 64.

## Attrition Relief and Revenue Stabilization

An additional advantage of decoupling is that it automatically addresses the financial attrition that occurs when average use is declining. Declining average use can result from large utility DSM programs, but also from DSM programs managed by third parties, DGS, high prices for energy commodities, and stricter appliance efficiency standards and building codes. The ability of decoupling to address declining average use from various sources helps to explain its popularity. For example, decoupling is popular with many gas distributors even though the declining average use that they have experienced has not been driven chiefly by their DSM programs.

Decoupling can also stabilize revenue in the face of short-run usage fluctuations resulting from changes in weather, the business cycle, and other economic conditions. Revenue from time-sensitive base rates can be particularly sensitive to demand fluctuations.

While decoupling reduces revenue risk, it does not guarantee that a utility will recover all of its costs. A utility operating under decoupling must still manage its costs to ensure that they don't exceed allowed revenue. This can be challenging, especially when the firm is operating under a multiyear rate plan.

## Efficient Regulation

Decoupling also has an impact on regulatory efficiency. On the one hand, it adds items to the regulatory agenda. Rates must be reset to effect revenue reconciliations, and a RAM is usually developed and instituted. However, the administrative cost of a decoupling true-up is not very different from administering a cost tracker. For both, the appropriate revenue adjustment must first be ascertained, and then allocated to service classes and recovered through a change in rates.[19]

On the other hand, by addressing important sources of financial attrition, decoupling can permit a reduction in the frequency of rate cases when average use is declining and/or the

[19] The administrative cost and rate churn resulting from decoupling can be reduced by timing them to occur when rates are adjusted for other reasons.

RAM is broad-based. A single rate case can result in thousands of pages of testimony and discovery documents. The desire to reduce the frequency of rate cases is an important impetus for approving cost trackers as well.

Decoupling can also help streamline rate cases when they do occur. Controversy over billing determinant forecasts in rate cases with future test years is reduced. Moreover, decoupling does not require complicated calculations to estimate load savings from DSM programs.

## 3.4. Criticisms of Decoupling

Decoupling does have critics. Some concerns are substantive but can be addressed by regulators in straightforward ways. Other concerns are misplaced.

### Rate Stability

Some critics of decoupling express concern that it can destabilize rates. However, soft caps on revenue adjustments can mitigate this problem without weakening the incentive and attrition relief benefits of decoupling. Experience has shown that the increased rate volatility due to revenue decoupling is manageable. In a recent study of US electric and gas decoupling true-ups, Pamela Morgan found that most rate adjustments have been small (64% were within ±2% of retail rates, and roughly 80% were within ±3%). She also found that a significant share (37%) of these adjustments represented rate *reductions* rather than *increases*.[20]

Another substantive concern is that decoupling true-ups may cause customers in one rate class to absorb the impact of reduced loads in other classes. A drop in business sector demand, for example, might lead to an increase in residential bills, or vice versa. However, this issue can be addressed through the use of separate service baskets.

### Tailored Service

Another substantive concern is that decoupling may decrease the utility's attentiveness to customer needs and preferences. Firms in competitive markets can suffer sharp reductions in sales when their rates or product quality are not competitive. However, the monopoly

[20] Pamela Morgan, "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations, Graceful Systems LLC, May 2013.

character of utility service limits the ability of customers to go elsewhere, and revenue decoupling can further reduce the chance of losing revenue when customer needs aren't met. As a result, utilities that operate under decoupling may feel less pressure to offer services tailored to customer needs. Concern about service quality repercussions can be addressed by developing service quality monitoring or incentive mechanisms and/or by permitting the Commission to disallow compensation for certain revenue losses due to outages.

### Uneconomic Bypass

The demand of some customers *is* sensitive (i.e., elastic) with respect to a utility's rate and service offerings. An example is an establishment that consumes large amounts of power, and which can develop self-generation capabilities or shift its operations to another service territory. If decoupling revenue from serving such customers makes the utility less responsive to their needs it could trigger the unnecessary loss of some loads, and/or a failure to attract new loads. These are both forms of uneconomic bypass that can result unnecessarily in higher rates for other customers. Concerns about the treatment of demand-elastic customers can be mitigated by applying decoupling selectively to residential and commercial customers, who generally have less elastic demands.

### Rate Case Frequency

Though static or declining average use by R&C customers is generally the rule for US electric utilities today, some utilities still experience *rising* average use. This can be true for reasons unrelated to the effectiveness of DSM programs. For example, customers in the service territory may have been slow to invest in air conditioning and the latest consumer electronics.

Where average use is rising, revenue per customer decoupling slows revenue growth and the frequency of rate cases will tend to increase. Utilities are more likely to oppose decoupling. The tendency of decoupling to increase rate case frequency and erode utility earnings between rate cases under these circumstances can be addressed with a broad-based RAM.

### Electric Vehicles

Though decoupling tends to improve a utility's environmental footprint, for some services the opposite is true. For example, decoupling can weaken a utility's incentive to promote electric vehicle ("EV") loads. Such loads can be encouraged by targeted performance incentive mechanisms or their exclusion from decoupling.

### Weakened Customer Conservation Incentives

It is sometimes argued that decoupling weakens customer incentives to pursue DSM. This argument is untrue. Under decoupling, customers *as a group* must pay for lost margins from DERs but *individual* customers can still reduce their bills by conserving. The upward drift in volumetric and other usage charges that often results from decoupling can also incent individual customers to conserve more. In effect, the revenue requirement is a "hot potato" and individual customers are incentivized to toss as much of it as possible to their neighbors.

## 4. Tracking of DSM Expenses

DSM expenses of utilities are usually tracked, for several reasons. One is that DSM programs are costly and often mandated. Tracking is fair for mandated costs, and encourages policymakers to make mandates reasonable. Another reason is that DSM expenses sometimes rise rapidly, and trackers can then reduce the need for frequent rate cases.

There is also a strong incentive argument for DSM cost trackers. Even when decoupling removes the throughput incentive, we have seen that a utility's incentive to contain load-related costs is often not strong. Utilities, additionally, have some incentive to trim untracked expenses between rate cases. Tracker treatment for utility DSM expenses removes the incentive utilities have to contain DSM spending between rate cases, helping to tip the balance of utility incentives in favor of DSM solutions.

# 5. DSM Performance Incentive Mechanisms

## 5.1. The Basic Idea

A targeted performance incentive mechanism ("PIM") links a utility's revenue mechanically to its performance as measured using metrics and targets. PIMs can strengthen performance incentives by providing awards and/or penalties. This is a popular form of performance-based regulation in the United States.

A demand-side management PIM links a utility's revenue to its performance as a DSM service provider. Demand-side management PIMs typically involve awards but no penalties. Awards may be granted for all load savings, but are typically contingent on attainment of a threshold level of savings. Awards are sometimes capped. Compensation for load savings can take several forms.

**Shared savings.** This approach grants the utility a share of the estimated net benefits that result from a DSM initiative. Net benefits are the difference between benefits and costs, so this approach encourages utilities to choose more cost-effective programs and to manage them more efficiently. However, the estimation of net benefits can be a complex and controversial issue in regulatory proceedings.

**Bonus.** Another possibility is to compensate the utility at a predetermined rate for each unit of load savings achieved (or for each unit of another desired outcome). The bonus rate may differ for different kinds of projects in the utility's portfolio. Though this approach does not require the estimation of net benefits, load savings must still be calculated.

**Management fees.** This alternative grants the utility an incentive equal to a specific share of program expenditures. Under this approach, the incentive calculation depends on the costs incurred (specifically, expenditures by the utility) but not on the benefits achieved. The utility is rewarded for spending money. However, its simplicity makes it an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), but its ease of administration has encouraged its use for other types of DSM programs as well. For example, in California a complex shared-savings PIM was recently replaced with a PIM based on management fees.[21]

**Amortization.** Under this approach, DSM expenses are amortized. A premium (also known as an "adder") is sometimes added to the ROE applied to these expenditures. This premium may be contingent on achieving certain performance goals. The return may be earned immediately through a tracker or accumulate in a regulatory asset. As is the case with management fees, the size of the incentive payment is determined by costs incurred (i.e., utility expenditures) rather than benefits achieved.

Several types of demand-side management PIMs require estimates of load savings. Load savings can be estimated using engineering models, off-the-shelf estimates of typical savings (aka "deemed savings"), or statistical analysis of customer billing data. Even with high-quality data, however, reliably estimating savings can be challenging due to several factors. These include free riders (customers who would have implemented the DSM measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient). The difficulty of measuring load savings varies by program.

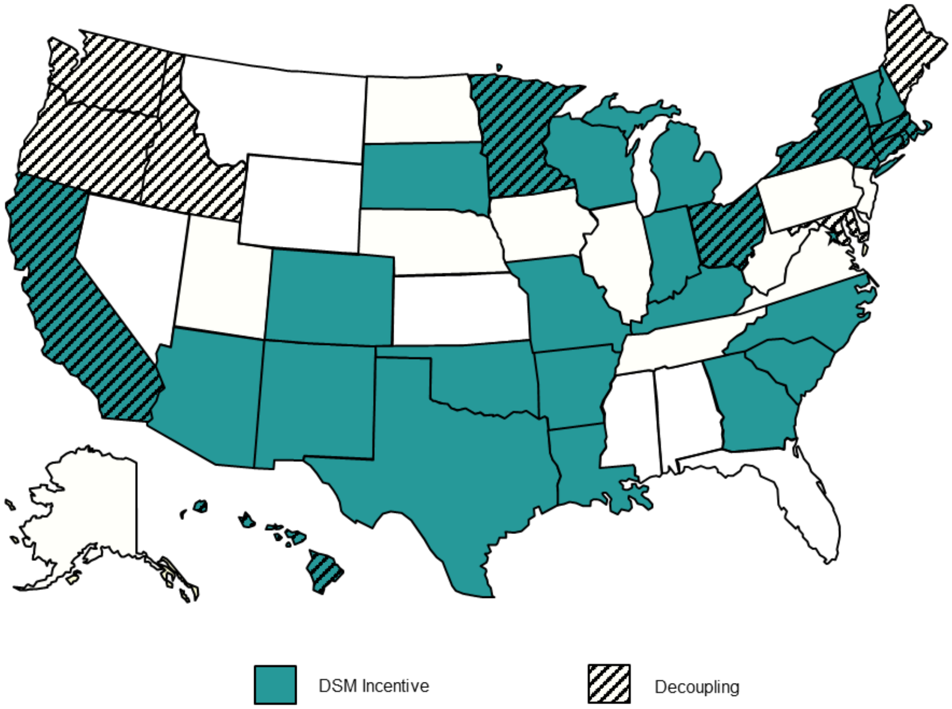
## 5.2. Precedents for Demand-Side Management PIMs

The 2015 ACEEE survey found that demand-side management PIMs are common for US energy utilities.[22] Figures 3a and 3b indicate states that had such PIMs for retail electric and gas utilities respectively, along with those that had revenue decoupling. On the electric side, it can be seen that a majority of retail jurisdictions had some form of demand-side management PIM. At least ten jurisdictions that had implemented demand-side management PIMs had also adopted revenue decoupling for the same industry. For example, Minnesota recently approved

[21] California Public Utilities Commission (2013). Decision 13-09-023, Rulemaking 12-01-005.

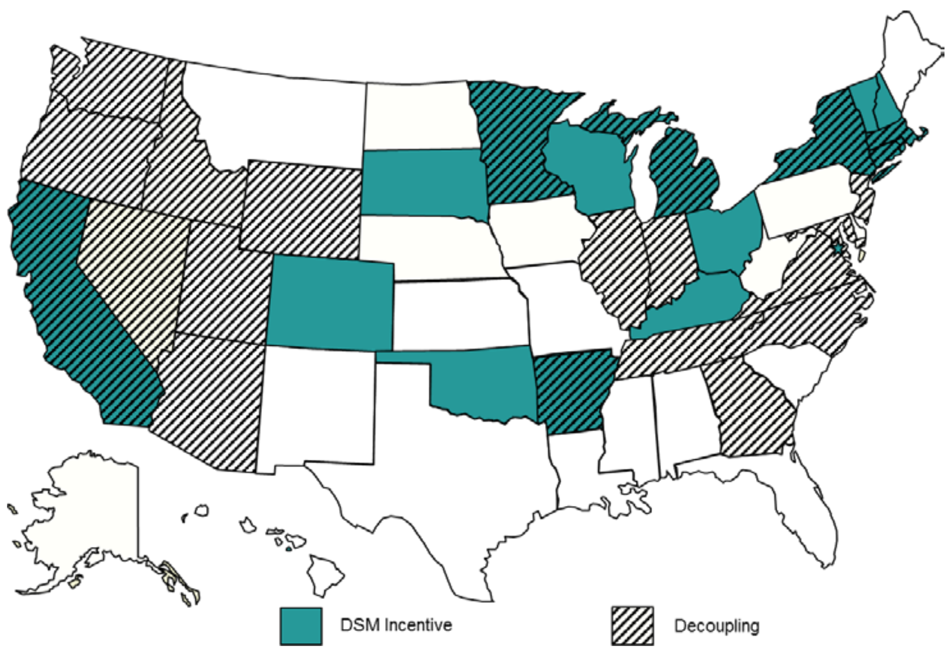
[22] American Council for an Energy-Efficient Economy, *op. cit.,* pp. 43-44

Figure 3a DSM Performance Incentive Mechanisms: Electric




.

Figure 3b DSM Performance Incentive Mechanisms: Gas




**REFERENCES**

DSM precedents drawn from American Council for an Energy-Efficient Economy, *The 2015 State Energy Efficiency Scorecards*, Report U1509, October 2015.

revenue decoupling for Xcel Energy but retained a demand-side management PIM for the company. Some states (e.g., Oregon and Maine) that have revenue decoupling but no demand-side management PIMs have an independent DSM program administrator. On the gas side, the ACEEE reported demand-side management PIMs in seventeen jurisdictions. Eight of these states also had revenue decoupling.

Most demand-side management PIMs focus on conservation programs and some states have decades of experience with them. Some existing PIMs also address peak-load management programs, but few if any address distributed generation or storage.

Most demand-side management PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, like those where transmission and distribution capex will otherwise be needed in the near future to replace aging assets or accommodate growing load. Consolidated Edison of New York's Brooklyn Queens Demand Management Program is a geographically targeted program with incentives in the form of amortization with an ROE adder.

### Peak-Load Management

There is growing interest in metrics and PIMs for peak-load management, for several reasons.

- Peak load is an important driver of utility cost.
- The load peakedness of many utilities is growing. Peakedness can be exacerbated by high penetration of distributed solar generation.
- Most utilities purchase power in managed markets with volatile prices. Low prices typically occur at night when demand is weakest and generation from wind resources tends to be highest. High prices generally occur in the early evening hours of summer and winter business days when demand is stronger and any solar power supplies are diminishing. Shifting demand to low-price periods can substantially reduce purchased-power costs.

- With AMI increasingly widespread, there are expanded opportunities to reduce load peakedness. Regulators are showing increased interest in using AMI more aggressively for this purpose.[23]
- With the cost of distributed storage falling, the responsiveness of customers to peak-load management initiatives may increase.

PIMs for peak-load savings are likely to be based on the reduction in peak kW. Calculation of such savings can be complicated since peak loads are sensitive to volatile external business conditions, such as the temperature on the hottest summer days. Permitting utilities to keep some of the revenue obtained from successful demand-side bids in managed bulk power markets is an alternative to a peak-load reduction PIM.

## 5.3. Pros and Cons of Demand-Side Management PIMs

PIMs offer both advantages and disadvantages as a way to incentivize utilities to foster DSM. On the plus side, they can in principle compensate utilities for base rate revenue losses from DSM programs that they cover. This reduces the utility's disincentive to foster DSM. Rate design freedom is preserved, and utility incentives to promote EVs aren't attenuated.

Where the throughput incentive is addressed by other Altreg tools like revenue decoupling, these PIMs are still quite useful because they can provide a *positive* incentive to embrace DSM. PIMs can encourage utilities to use DSM to reduce load-related costs like those for fuel, purchased power, load-related capex, and environmental damages. This principle has been recognized by the MNPUC. In its 2016 order adopting modifications to its demand-side management PIM, the Commission stated that

> The Commission may authorize a utility to recover CIP-related costs via a Conservation Cost Recovery Charge built into the utility's rates. And the Commission may authorize a utility to implement revenue decoupling, a rate design that helps ensure that a utility recovers certain fixed costs regardless of how much energy it sells. But while these cost-recovery mechanisms may

---

[23] See, for example, "California Regulators Approve Major Overhaul of Residential Electric Rate Design," *SNL Electric Utility Report*, 13 July 2015 and "California Mandates TOU Pricing for Residential Customers," *PUR Utility Regulatory News,"* Letter #4229, 17 July 2015.

> reduce a utility's *disincentive* to depress its own sales via conservation, they do not affirmatively *encourage* the practice of promoting conservation.[24]

Shared savings PIMs have the additional advantage of encouraging *efficient* DSM programs. This is particularly beneficial due to the fact that DSM program expenses are typically tracked.

In contrast to decoupling and fixed/variable pricing, demand-side management PIMs permit compensation for DSM programs without denying utilities the benefit of any growth in average use that occurs due to demand growth. This helps to explain the popularity of these PIMs with electric utilities since, as we have seen, many of these utilities experienced rising average use until recently.

Demand-side management PIMs also have drawbacks. Award rates may not be set high enough to eliminate the throughput incentive and provide sufficient encouragement to use DSM for cost containment. In addition, some PIM styles can allow the rewards granted to utilities for load savings to become sizable over the years.

A bigger problem is that many types of PIMs can involve complex calculations that invite controversy in regulatory proceedings. As a consequence, the scope of DSM programs addressed by PIMs is often limited to those where it is practical to estimate load savings and net benefits. Some jurisdictions sidestep the chore of calculating net benefits.

Simplicity is an important goal, but in this case encourages utilities to focus on DSM programs with more easily measured impacts. Other DSM initiatives that are equally or more cost effective may be neglected. Neglected initiatives may include changes in rate designs, campaigns to tighten state and federal building codes and appliance efficiency standards, cooperation with third party vendors of energy services, and other efforts to transform energy service markets. By motivating utilities to improve their performance with respect to specific programs and metrics, PIMs may thus lead to mediocre and even poor performance in other DSM areas.[25] For example, utilities with sizable conservation programs may nonetheless

[24] MNPUC, Docket E,G-999/CI-08-133, August 2016, p. 3.

[25] This was a concern of the New York PSC in its Track 2 decision in its Reforming the Energy Vision ("REV") proceeding, NYPSC, Case 14-M-0101, p. 63.

propose rate designs with low usage charges that discourage DSM or may be slow to adopt time-sensitive pricing. Designing PIMs that encourage a wider range of DSM initiatives is a contemporary challenge in regulation.

Demand-side management PIMs also do not address declining average use that results from external business conditions. For example, they have not offered gas distributors relief from declining average use from drivers other than their own DSM programs. They are similarly of limited use in protecting utilities from demand volatility.

These deficiencies of demand-side management PIMs help to explain why they are rarely been used to encourage DGS. Calculation of DGS benefits is complex, and utilities often lack the power to steer DGS to times and places where net benefits are substantial. Load impacts and benefits attributable to utility effort can be difficult to ascertain. Consequently, utilities with demand side management PIMs can have still have a weak incentive to use DGS as a cost containment tool, and may oppose DGS. Efforts to discourage DGS can also discourage DSM.

On balance, demand-side management PIMs have many benefits in modern regulation, and this helps to explain their popularity. Some commentators have described the combination of revenue decoupling, DSM cost trackers, and demand-side management PIMs as the three legs of a stool incentivizing utilities to aggressively pursue DSM.[26]

# 6. Fixed/Variable Rate Designs

## 6.1 Fixed/Variable Basics

Fixed/variable pricing is an approach to rate design that limits recovery through variable charges of costs that are fixed, in the *short* run, with respect to system use. A greater proportion of fixed costs are recovered through fixed charges, such as customer and facilities charges. Customers pay a substantial fixed monthly charge for service regardless of their usage

[26] See, for example, Nowak, S., Baatz, B., Gilleo, A., Kushler, M., Molina, M., & York, D. (2015). *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, American Council for an Energy-Efficient Economy, Report U1504.

and thus have less ability to reduce their bills with lower usage than under legacy rate designs. *Straight* fixed/variable ("SFV") rate designs recover *all* fixed costs through fixed charges. A rate design that involves fixed charges, but does not recover all fixed costs through them is sometimes called "*modified*" fixed/variable ("MFV") pricing.

## 6.2 Fixed/Variable Precedents

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Current precedents for fixed/variable pricing in retail energy utility ratemaking are shown below in Figure 4. It can be seen that fixed/variable pricing has been considerably more common for gas distributors than electric utilities. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida and Oklahoma have fixed charges that vary with long-term consumption patterns.

## 6.3 Pros and Cons and Fixed/Variable Pricing

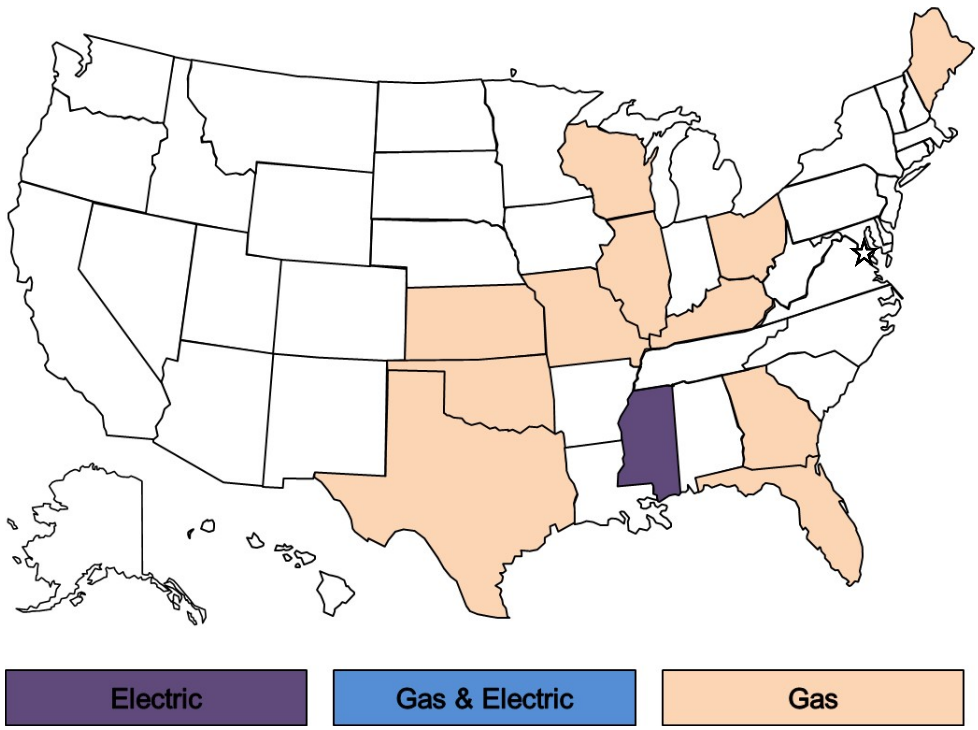
### Advantages

Straight fixed/variable pricing can remove the throughput incentive, decreasing utility reluctance to pursue a wide range of actions that could foster DERs. As we discussed in the section on revenue decoupling, this benefit is greater when utilities undertake DSM programs, but is still substantial when they do not. SFV pricing also reduces the earnings risk of demand volatility.

The impact of SFV pricing on revenue growth is similar to that of revenue-per-customer decoupling. Base-rate revenue grows between rate cases at roughly the pace of customer growth. When average use is *declining*, base revenue will therefore grow more rapidly with fixed/variable pricing than with legacy rate designs so that rate cases are less frequent. This benefit is achieved even if the decline is largely driven by external business conditions.[27] Controversy over future billing determinants in rate cases with forward test years is reduced. In contrast to revenue decoupling, these outcomes are achieved with stable rates. Moreover,

[27] This helps to explain the popularity of fixed/variable pricing amongst gas distributors.

Figure 4 Fixed/Variable Pricing Precedents by State




administrative cost is unusually low since fixed/variable pricing requires neither decoupling true-ups nor load impact calculations.

## Is SFV Pricing Efficient?

Other touted advantages of fixed/variable pricing include its ability to foster efficient DERs by sending customers better price signals. It is sometimes argued as a matter of principle that fixed charges should address fixed costs. These claims are more controversial. Usage charges should communicate to customers the cost of system use. Many costs of base rate inputs that are fixed in the *short* run with respect to system use are not in the *medium* and *long* run. For example, the costs of many distribution facilities (e.g., substations and transformers) vary with local circuit coincident peaks.

The question then arises as to when usage rates should rise to reflect marginal costs, if they are to elicit the behavior from customers that permits containment of these costs. Many customers need price signals well in advance of a rise in short-run marginal cost if they are to change their behavior in a timely fashion. Having high usage charges for base rate inputs only when and where marginal costs are high can confuse customers and violate rate gradualism principles.

In addition to restricting the use of volumetric charges that are fixed or seasonally varying, SFV pricing also restricts the potential for rates to send time-varying price signals that reflect longer run marginal costs. It thus reduces regulators' ability to use time-varying rates to encourage rooftop solar PV owners to boost evening output or install storage, or customers with EVs to charge their vehicles at night.

Another consideration is the environmental and other externalities that system use gives rise to. While these are traditionally disregarded in utility rate designs, environmental groups are correct to point out that a truly efficient price to the customer per kWh of power delivered from the grid would reflect marginal environmental costs, and that these are not reflected in energy prices in most parts of North America today. Large volume residential customers do more damage to the environment than small volume customers, and bear more responsibility for costly measures that may ultimately be required to contain damage. If recovery of a utility's revenue requirement can be assured by other means, such as revenue decoupling, utilities can, in the absence of appropriate emissions taxes, take some account of externalities in the design of their rates for producing and delivering power.

### Disadvantages

The various disadvantages of fixed/variable pricing have prompted environmental organizations to oppose it in many proceedings. The preceding discussion suggests that a salient disadvantage of fixed/variable pricing is the restrictions it places on rate designs. Rate designs have an important impact on customer incentives for DERs because they affect the payback period on investments (e.g., those for better insulation) that these initiatives involve. DERs are generally encouraged by high usage charges. While volumetric charges are not ideal for sending signals concerning the long-run cost of coincident (system or circuit) peak demand, they can be made more cost-causative to the extent that they are higher in seasons and hours of the week when marginal costs are highest. Implementation of SFV pricing can also produce sharp increases in bills for low income and other small-volume customers.

In view of these disadvantages, and the widely accepted principle of rate gradualism, commissions accepting the merit of fixed/variable pricing are nonetheless likely to phase in higher customer charges gradually. Fixed charges may never be permitted to address some costs that are largely fixed in the short run but vary with system use in the long run. The resultant *modified* fixed/variable pricing is considerably less effective than revenue decoupling in removing the throughput incentive and the risk of demand volatility and time-sensitive rates, and in addressing potential attrition from declining average use. The utility will accordingly be less likely than under revenue decoupling to embrace all cost effective DERs and more likely to take steps to discourage DERs.

In addition, while modified fixed/variable pricing restricts rate design less than the SFV approach, to the extent that it ignores long run marginal costs and external costs it can nevertheless limit the potential for rates to send appropriate price signals to customers concerning DER decisions. Modified fixed/variable pricing is thus suboptimal from an incentive point of view, in relation to both utility and customer behavior.

Other disadvantages of fixed/variable pricing also merit note. Like revenue per customer decoupling, for example, fixed/variable pricing increases financial attrition and the frequency of rate cases when and where average use is rising.

# 7. Multiyear Rate Plans

## 7.1. The Basic Idea

DSM and other DERs can reduce load-related cost like those for generation and transmission investments. This suggests that a utility's incentive to embrace DERs can also be strengthened by increasing its motivation to contain load-related costs. Multiyear rate plans ("MRPs") are one means of accomplishing this.[28] The basic idea of an MRP is to compensate a utility for its services over several years with revenue that, while reflective of changing cost pressures, does not closely track the utility's *own* cost of service closely. MRPs utilize two tools to relax the link between a utility's own cost and its revenue:

[28] Incentivization of trackers and formula rates for load-related costs is an another means of accomplishing this.

1. A moratorium is imposed on general rate cases that typically lasts two to four years.
2. Between rate cases, an attrition relief mechanism ("ARM") automatically adjusts rates or the revenue requirement for changing business conditions (e.g., inflation and customer growth) without linking the relief to the utility's own cost growth. Methodologies for the design of ARMs include cost forecasting and inflation and productivity indexing.

The combination of a rate-case moratorium and the ARM approach to rate escalation can strengthen a utility's cost containment incentives, despite a material reduction in regulatory cost. MRPs nonetheless typically address some costs separately from ARMs using trackers. A "tracker/freeze" approach is popular today, which combines tracker treatment of some rapidly rising costs with a rate freeze.

Some MRPs feature earnings sharing mechanisms which share surplus and/or deficit earnings between utilities and customers. Surplus or deficit earnings result when the ROE deviates from its commission-approved target. Off-ramp mechanisms may permit suspension of a plan under pre-specified outcomes such as persistently extreme ROEs.

Most MRPs also include PIMs. These have in the past been used chiefly to balance the incentives for cost containment with incentives to pursue other goals, such as the maintenance or improvement of service quality, which matter to customers and the public. Many MRPs have also included demand-side management PIMs, which further strengthen utility incentives to use DSM to reduce load-related costs. In the future, MRPs are likely to include PIMs that address new concerns. For example, PIMs may afford utilities a share the benefit of peak-load management and DGS, or address the quality of connections and other services provided to DGS customers.

## 7.2. MRP Precedents

MRPs are the most common approach to Altreg around the world. They were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies.[29] In these industries, a major attraction of these plans was their ability to protect core customers so that utilities could have more flexibility in fashioning rates and services for markets with diverse competitive pressures and complex, changing customer needs.

US and Canadian precedents for MRPs in the electricity and gas utility industries are shown in Figures 5a and 5b. In the US, MRPs have traditionally been most common in California and the Northeast. Plans have recently been adopted by vertically integrated electric utilities in several other states, including Florida, North Dakota, Virginia, and Washington. The FERC uses MRPs to regulate oil pipelines.

Canada is moving towards MRPs for gas and electric power distribution in its four most populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Great Britain, and New Zealand are long-time practitioners.

## 7.3. Advantages of MRPs for Encouraging DERs

MRPs can improve utility incentives to embrace DERs if they are properly designed. Their chief advantage is the general incentive they can provide to slow growth in the rate base. Since DERs can be an effective tool for reducing rate-base growth, utilities operating under MRPs have more incentive to embrace them. For example, if a utility uses DSM or DGS to reduce its need for substation capex during a plan, it can keep some of the resultant cost savings for several years.

MRPs can also incorporate mechanisms to weaken the throughput incentive. For example, it is easy to add revenue decoupling. When an MRP features decoupling, the ARM escalates allowed revenue and thus operates as a broad-based revenue adjustment mechanism, as discussed in Section 3. Utilities in California and Hawaii operate under MRPs with decoupling and have experienced some of the highest levels of distributed solar generation penetration in the United States.[30] Utilities in New York and Washington state also

[29] Several MRPs have been approved over the years for Minnesota phone companies.
[30] Solar generation is also encouraged in these states by other conditions, including strong sunlight.

Figure 5a Recent US Multiyear Rate Plan Precedents by State[31]

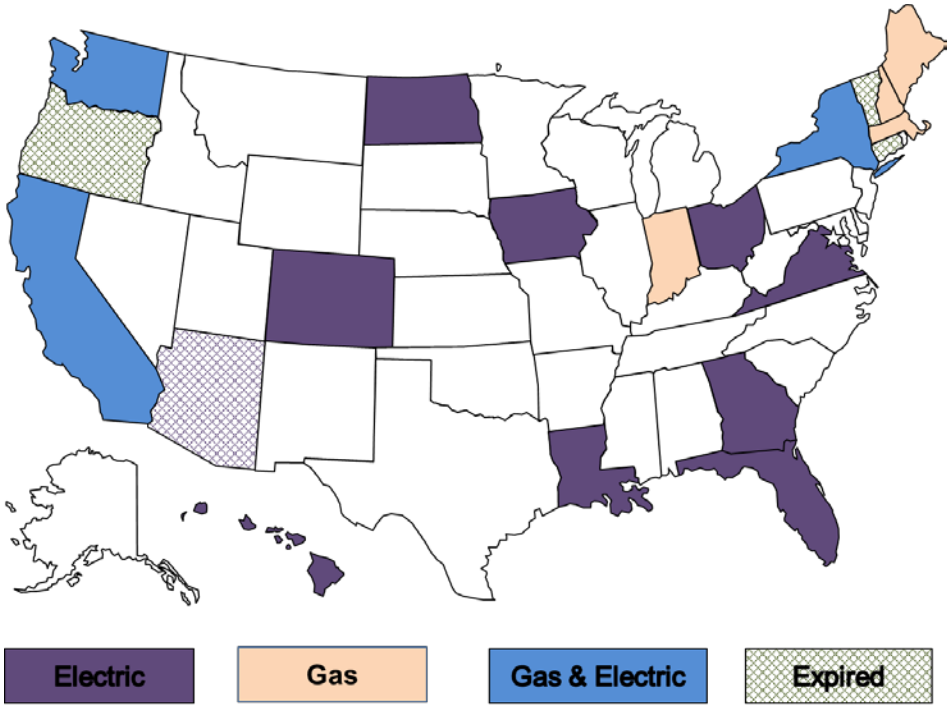
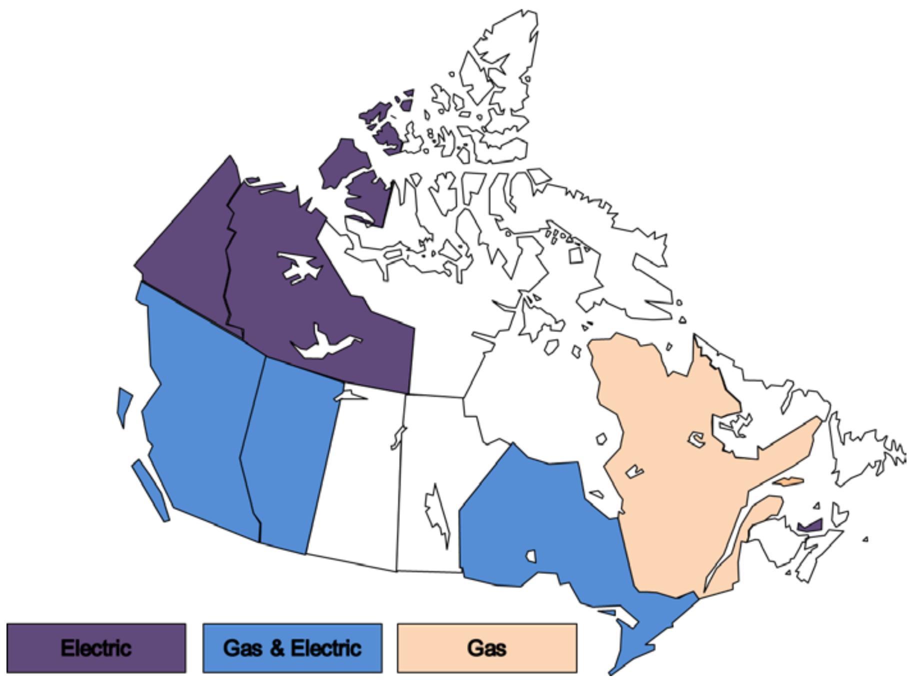



Figure 5b Recent Canadian Multiyear Rate Plan Precedents by Province




[31] We do not include the Xcel Energy (MN) plan on this map because its recently approved MRP has a term of only two years.

operate under MRPs with decoupling. The "RIIO" approach to utility regulation in Britain combines MRPs and decoupling as well.[32]

Additional positive incentives to embrace DERs are desirable since the cost containment incentives generated by MRPs can still be muted by provisions like cost trackers, earnings sharing, and the occasional rate cases. These additional incentives can be achieved with a combination of demand-side management PIMs and tracker treatment of DSM expenditures. The combination of an MRP, revenue decoupling, DSM performance incentive mechanisms, and the tracking of DSM-related costs can provide *four* "legs" for the DSM "stool." While MRPs are often complex, they can nonetheless materially reduce the cost of regulation by reducing the frequency of rate cases.

### 7.4. Limitations of MRPs

MRPs also have certain limitations that merit mention. For example, many US jurisdictions have limited experience with these plans. Design of the ARM and cost tracker provisions of MRPs can be controversial. Utility operating risk can increase. Measures to contain risk such as earnings sharing mechanisms can reduce the touted performance incentives.

## 8. Application to Otter Tail Power

### 8.1. Background

OTP is a small investor-owned electric utility based in Fergus Falls, MN. It serves about 131,000 customers, most located in small towns and nearby rural areas of western Minnesota and the eastern Dakotas.[33] The company has vertically integrated electric operations. In 2015, OTP's generation equaled 40% of its power supplies, and under Minnesota regulation OTP can still qualify to build new generation capacity to serve native loads.[34]

[32] The acronym RIIO stands for Revenue = Incentives + Innovation + Outputs.

[33] Direct Testimony of Thomas R. Brause in Docket E017/GR-15-1033, p. 3. Most rural areas of the region are served by cooperatives, however.

[34] OTP 2015 FERC Form 1, p. 401a.

Low-cost wind resources for generating power are unusually abundant in OTP's service territory and a promising source of exports that can stimulate the local economy. However, coal-fired power plants still accounted for about 78% of OTP's generation volume in 2015.[35] Wind and hydro facilities accounted for about 21% of the volume and combustion turbines and small diesel units for about 1%. The Company estimates that in 2015 about 19% of the electricity consumed by its retail customers was generated from renewable resources.[36]

The demand mix of OTP is diverse. In 2015, commercial customers accounted for around 35% of electric revenues. Residential customers accounted for 32% of revenues while industrial customers accounted for around 30%.[37]

OTP is a member of the Midcontinent Independent System Operator ("MISO") and purchases sufficient power in MISO's energy market to offset its retail supply deficit. The Company has a generation capacity requirement based on MISO Module E requirements. It must have sufficient Zonal Resource Credits to meet its monthly weather normalized demand, plus a reserve margin. This is achieved through a combination of Company-owned generation capacity, additional capacity secured by bilateral contracts, and load management control capabilities.[38]

OTP recovers its transmission cost from MISO using a MISO Tariff Attachment O formula rate. It is then charged by MISO for its use of the transmission system under the Network Integration Transmission Service ("NITS") and Network Upgrade Charge ("NUC") rates. Both of these charges are assessed on the basis of OTP's monthly peak demands. These rates do not vary seasonally even though the demand for transmission service in the region has summer and winter peaks.

Retail base rates in Minnesota are adjusted in occasional rate cases that often feature forward test years. Costs of OTP's fuel, purchased power, environmental compliance,

---

[35] Otter Tail Corp., Form 10-k, February 2016, p. 7.
[36] Brause, *op. cit.,* p. 4.
[37] Otter Tail Corp., *op. cit.*, p. 6.
[38] Otter Tail Corp., *op. cit.,* p 7.

renewable energy, transmission capex, and DSM are addressed by cost trackers.[39] OTP proposes continuance of these trackers. The Company is not proposing major Altreg reforms, like revenue decoupling or a multiyear rate plan, which were recently proposed by Xcel Energy in Minnesota.[40]

Each regulated electric utility in Minnesota is required by Section 216B.241 of the Minnesota Statutes to make annual investments and expenditures in cost-effective energy conservation. The law provides a default annual goal of achieving cost-effective energy savings equivalent to 1.5% of average retail sales. The Minnesota Conservation Improvement Program ("MNCIP") also includes a Financial Incentive Mechanism that encourages utilities to pursue conservation. This mechanism, as modified in Docket E,G99/CI-08-133, shares the estimated net benefits of conservation programs between customers and utilities. For an electric utility that achieves energy savings of at least 1.0 percent of retail sales, the mechanism awards the utility a share of the net benefits, increasing by an additional 0.75 percent for each additional 0.1 percent of energy savings the utility achieves, up to 1.7 percent of retail sales. The Net Benefit Caps are set at 13.5 percent in 2017, 12.0 percent in 2018, and 10.0 percent in 2019.[41] For OTP, incentive payments were about $2.6 million in 2012, about $4 million in 2013, and about $2.9 million in 2014.[42]

Section 216B.1611 Subdivision 2(b) of the Minnesota Statutes states that "The commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation." However, no such mechanisms have been approved.

OTP currently operates under a 2014-2016 Triennial MNCIP plan approved by Deputy Commissioner William Grant of the Minnesota Department of Commerce. The Company has received rewards for its conservation programs. Its saving goals for the 2014-2016 period were just a little above the statutory minimum goal, but the proposed Triennial MNCIP plan for the

[39] Some costs of fuel, purchased power, and DSM are included in base rates.
[40] A public utility may propose a multiyear rate plan under Minn. Stat. 216B.16.19.
[41] Docket No. E,G999/CI-08-133, Order (Aug. 5, 2016), p. 28.
[42] Docket No. E,G999/CI-08-133, DOC DER Report (Jul. 14, 2015), p. 29.

2017-2019 period features 1.75% average annual load savings. In OTP's rate case filing the Company forecasts flat average use for residential and small commercial customers for many years in the future.

Another section of Minnesota law permits investor-owned utilities to apply for a Value of Solar ("VOS") tariff in lieu of net metering for customers with solar facilities, and as a rate for community solar gardens.[43] The legislation requires that the VOS tariff take into account environmental benefits.

Minnesota law favors conservation over the addition of new resources and the use of renewable resources where practicable when new supplies are needed. A state renewable energy standard requires OTP to generate or procure sufficient renewable generation to provide retail electric customers with 20% of their power supplies by 2020 and 25% by 2025.[44] Each utility must obtain approval from the MNPUC of a 15-year advance integrated resource plan ("IRP"). In its latest IRP ruling, the Commission authorized OTP to prepare for the retirement of the aging Hoot Lake coal-fired generating station and to increase its gas-fired, wind-powered, and solar generation capacity.[45]

Section 216B.03 of the Minnesota Statutes states that "to the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use." OTP's standard tariffs for residential, farm, and small general service customers are fairly traditional. A substantial portion of base rate revenue is raised from seasonally varying volumetric charges. The Company also has rates in Minnesota for residential demand control, general service time of use and time of day, real time pricing, and controlled and interruptible services.

OTP's current rate case filing is its first since 2010 and its second since 2007. A 2016 test year is employed. The Company is requesting a 9.8% revenue increase. Costs, chiefly for capex, that are currently recovered in OTP's Transmission Cost Recovery Rider and Environmental Cost

[43] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.
[44] Otter Tail Corporation, *op. cit.*, p. 11.
[45] MNPUC, Docket E-017/RP-13-961, December 2014.

Recovery Rider would be transferred to base rates at the conclusion of the case. After the rate case, the sizable cost associated with the recent capex would then gradually decline with depreciation while the associated revenue would gradually grow with billing determinants.

According to policy witness Brause, OTP has been engaged in an extensive capex program since 2012 which is expected to continue through 2020.[46] $536 million was invested from 2012 to 2015. Most of this capex has been for environmental compliance [e.g., on an air quality control system ("AQCS") for the Big Stone (coal-fired) power plant] and transmission (including MISO CapX2020 projects), along with routine replacements, upgrades and extensions.

Another $858 million of capex is planned between 2016 and 2020. The planned capex includes gas-fired generation ($162 million), wind- and solar-powered generation ($190 million), and transmission ($213 million) projects.[47] Some of the transmission projects facilitate the flow of North Dakota's wind-generated power surpluses across OTP's service territory to the Twin Cities and other markets to the east. The more than $480 million Minnesota rate base proposed in this rate case is more than double the $215 million rate base approved for 2009.

The Company also proposes new rate designs. Customer charges would rise much more rapidly than volumetric charges for services to small volume customers. Will Nissen, in his testimony on behalf of Fresh Energy, notes that the proposed increased residential customer charge diminishes the customer's financial incentive to conserve energy by reducing the volumetric portion of the customer's rate.[48] It also reduces the incentive to adopt DGS.

Rate design evidence was also submitted by Amparo Nieto of NERA Economic Consulting. She prepared estimates of OTP's marginal cost for the 2016-2020 period. Her estimates of the marginal costs of customer services for each rate class are considerably higher than the proposed new customer charges, suggesting a rationale for further hikes in customer charges and cuts in volumetric charges in the future.

[46] Brause, *op. cit.*, p. 5.
[47] Otter Tail Corp., *op. cit.,* p. 23.
[48] Nissen Direct, p. 4.

The testimony of Mr. Prazak and the marginal cost research and testimony of Ms. Nieto are controversial in several respects.

- In addition to the recovery of customer-related expenses like those for metering, billing, and the service drop, Ms. Nieto notes that fixed charges "*may also be used* to recover the cost of connecting to the local delivery system, involving the required transformers, secondary lines or local primary lines that may need to be added or expanded to accommodate the expected customer's maximum demand over the life of the facilities" (italics added), even though she elsewhere states that these costs are driven by the kW of "design demand."[49] David Prazak notes in his testimony that winter space heating loads cause the company to purchase larger transformers.[50]. OTP does not propose to address local delivery costs with fixed charges.
- Ms. Nieto's marginal cost study addresses only the marginal cost of distribution in the near term. This depends on OTP's forecasted need for distribution capex in the next few years. A volumetric charge based on the *long run* marginal cost of distribution would be higher.
- Ms. Nieto's study suggests that OTP's marginal cost varies substantially by time of use, being far higher in peak periods than in other periods. While this could provide a rationale for a buildout of advanced metering infrastructure and default use of time-sensitive pricing, the biggest change in rate design that OTP proposes on the basis of the study is a reduction in volumetric charges.
- Ms. Nieto provides a discourse on pp. 4-5 on the *general merits* of marginal cost pricing, stating on p. 5, for example, that "keeping volumetric prices at marginal costs is justified by economic theory." She goes on to state that when volumetric rates are set above marginal costs they encourage suboptimal levels of consumption and self-generation. With regard to the latter she states on p. 10 that

[49] Direct Testimony of Amparo Nieto in Docket E017/GR-15-1033, p. 3.
[50] Direct Testimony of David Prazak in Docket E017/GR-15-1033, p. 23.

> Rates that recover marginal costs in volumetric charges and recover local facilities costs and customer costs in a fixed charge will help ensure that consumer decisions to install rooftop solar are based on economically efficient incentives. Minnesota has an opportunity to be a leader in promoting clean distributed resources in a way that serves environmental goals without unduly burdening non-participant customers. Getting the right rate structure in place as the market gets ready to embrace DG will be critical in ensuring that outcome.

However, her marginal cost study does not consider environmental externalities or long-run marginal costs. Hence, some of her general statements on the merits of marginal cost pricing can be correct even though her study is insufficient to devise rates that send correct price signals to customers concerning DERs.

With respect to revenue decoupling, Ms. Nieto states on p. 9 of her testimony that revenue decoupling is not a substitute for appropriately designed fixed charges. She explains this position with the following commentary.

> Decoupling may be an appropriate mechanism to remove a utility's disincentive to promote energy efficiency or conservation, but it perpetuates cross subsidies, as the mechanism does nothing to make sure customers see the right price signals. All customers will see rate surcharges to recover the lost revenue between rate cases, meaning there are still intra-class subsidies and inefficient use of resources.

We have seen, however, that revenue decoupling can encourage utilities to improve the efficiency of their rate designs.

As for the testimony of Mr. Prazak, he counts among his "rate structure objectives" the following.

> The rate design should give OTP a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
>
> The rate design should promote efficient use of resources, conservation, and use of renewables. This implies giving consumers price signals that reflect marginal

> costs, including seasonal differences and, where reasonably possible, time-of-day (TOD) differences.[51]

On p. 6 Mr. Prazak states, relatedly, that "rates must give the utility the opportunity to recover its embedded costs."

These goals sometimes conflict. Correctly calculated marginal cost rates do not ensure cost recovery or encourage revenue to track costs, and rates that do ensure cost recovery may not promote efficient use of resources, conservation, and use of renewables. Fortunately, revenue decoupling is available to permit rate designs that encourage efficient DERs even if they do not ensure cost recovery.

How does Mr. Prazak propose to balance these competing goals? He notes on p. 4 that "Consistent with *OTP's* rate design objectives, I based our rate structures on the structure of *OTP's* marginal costs (italics added)". Thus, recovery of the revenue requirement has taken precedent over optimal price signals in the Company's rate design proposals.

## 8.2. Analysis and Recommendations

Our general analysis of utility performance incentives and our review of the Company's situation suggests that Otter Tail does not have appropriately strong incentives to embrace efficient DERs. This is particularly worrisome since the Company takes the lead on DSM programs. Starting with the throughput incentive, we find that even with the proposed hikes in customer charges, most revenue addressing costs that are fixed in the short run with respect to system use would continue to be addressed by usage charges. There is thus potentially a strong throughput incentive and a concomitant disincentive to embrace DERs.

Forward test years can reduce the throughput incentive by helping rates reflect slowing growth in system use in the rate effective years following rate cases. However, with a substantial share of its capex cost addressed by trackers and the addition of recent high capex to its rate base, OTP does not need to file frequent rate cases. Company witness David Prazak states in his testimony that "OTP anticipates rates to remain unchanged for at least 3 years."[52]

[51] Direct Testimony of David Prazak in Docket E017/GR-15-1033 p. 4
[52] Prazak, *op. cit.*, p. 13.

Another cause for concern is the Company's weak incentive to contain many load-related costs. While the expected rate case cycle would provide some incentive to contain some load-related costs (e.g., distribution substation and transformer capex), most of OTP's load-related costs are subject to cost trackers or formula rates. Otter Tail's finances are also insensitive to many kinds of environmental damage that its operations cause.

The MNCIP Financial Incentive Mechanism substantially improves the incentive balance with respect to conservation programs it covers. However, the mechanism doesn't encourage DGS or a wide range of initiatives OTP can take to promote conservation and peak demand management.

Otter Tail thus has weak incentives to take many measures that can foster efficient DERs. Perhaps reflecting this, the Company's conservation goals only slightly exceed the statutory minimum. Instead of moving in the direction of time-sensitive pricing that could encourage efficient DERs, the Company is proposing a reduction in volumetric charges that discourages all forms of DERs for small-volume customers.

Based on this analysis, we believe that reforms to OTP's regulatory system are needed to encourage efficient DERs. Most importantly, revenue decoupling should be instituted. This can immediately and completely remove the throughput-related disincentive to embrace efficient DGS and peak load management and the full range of initiatives that encourage conservation. Debate over future billing determinants can be reduced in forward test year rate cases. We also believe that the MNCIP Financial Incentive Mechanism and tracker treatment of DSM expenses should continue in order to provide some positive incentive to use DSM for cost management.

Additional reforms are needed to improve DER incentives that may go beyond what can be addressed in this rate case. These include the development of positive financial incentives for OTP to encourage efficient DGS and a wider range of DSM initiatives. A multiyear rate plan can further strengthen incentives to contain load-related capex. A multiyear revenue per customer freeze is one approach that merits consideration for Otter Tail.

We propose a revenue decoupling system broadly similar to that which the Commission approved for Xcel Energy in its last rate case.[53]

- Decoupling would apply to residential, farm, and general services (excluding large general services).
- Separate service baskets would apply to residential and farm services and to general services. The use of multiple baskets protects customers in each basket from rate adjustments resulting from the demand trends of dissimilar customers.
- The proposed RDM would adjust all usage charges in a given service basket equiproportionately. Charges that fluctuate only with the number of customers (e.g., customer charges) would not be included in the RDM, as revenue collected through them is already decoupled from usage.
- The RDM would effect *full* decoupling subject to the constraint that surcharge adjustments due to the revenue decoupling system would be capped at 3% annually. Residual revenue variances would be eligible for true-up in the following year.
- Revenue per customer would be decoupled, so that the revenue requirement of each service basket rises gradually with the number of customers in that basket.
- Decoupling adjustments would be applied in each month of the following April-March period.
- OTP would be required to file a plan proposing education and outreach program to customers explaining the goals and operations of its RDM program.
- The decoupling adjustment would appear as a separate rider on customers' bills to enhance transparency.
- Sales volumes attributable to electric vehicle loads would be exempted from decoupling.

An illustrative tariff sheet is found in Appendix 2.

[53] MNPUC (2015) op cit.

## 8.3. Decoupling Illustration

RDM demonstration models have been prepared for two service baskets: Residential and Farm, and General Service. These models can be found in Appendix 1. The RDMs featured in these models true up actual revenues to allowed revenues on a per-customer basis within each basket. While the operation of the models is demonstrated for 2016, the first year for which decoupling would apply would likely be 2017.

The RDM for each basket first generates a forecast of net usage-charge revenue per customer in the test year (2016).[54] This is done by first multiplying the forecasted test-year sales volume and (where applicable) billing demand and facilities charge demand of each rate class by OTP's proposed charges for that class. [55] The resulting revenue forecast is then adjusted to remove the components of usage-charge revenue that recover MNCIP and energy costs. This adjustment avoids double counting, since the MNCIP and energy cost components are subject to periodic true-ups of their own that expedite recovery of these costs.

Next, the RDM for each service basket calculates the test year net usage-charge revenue *per customer* that OTP is authorized to recover by taking the ratio of forecasted net usage-charge revenue to the forecasted number of customers served. The net usage-charge revenue ultimately authorized for each service basket in 2016 is then obtained by multiplying the authorized net usage-charge revenue per customer by the actual number of customers served. The data representing actual customers in the models are constructed for demonstration purposes and intentionally differ slightly from the forecasts; in a real RDM these should be historical numbers.

Next, the RDM computes the deferral amount (labeled "RDM deferral" in the models) for each service basket. This is the positive or negative variance between the *authorized* net usage-charge revenue and the *actual* net usage-charge revenues.[56] The method used to

---

[54] The forecasts ultimately used should be the ones approved by the Commission in the present proceeding, if available.

[55] Use of OTP's proposed rates is for demonstration purposes, and does not constitute an endorsement of their propriety. At the end of this proceeding, the usage rates and billing determinant forecasts approved by the Commission should be used.

[56] The actual revenues used in the models are constructed for demonstration purposes, but in a real RDM these should be historical numbers.

compute the actual net usage-charge revenues is analogous to that used for the forecasted net usage-charge revenues. First, each usage charge is multiplied by the actual value of its corresponding billing determinant to obtain the actual gross usage-charge revenues for each rate code. Next, these are summed to obtain the actual gross usage-charge revenues for the service basket as a whole. Finally, the components of the usage-charge revenue that recover MNCIP and energy costs are netted off, yielding the actual net usage-charge revenues.[57]

Each month the RDM places the deferral amount in a balancing account, which tracks the unrecovered net variances for later true-up. Following the example of other Minnesota utility RDMs, the demonstration models do not apply a carrying charge to the monthly deferral amounts. Although this simplifies the calculation, it prevents the full decoupling of revenue from usage by ignoring the time value of money. For this reason, the application of an appropriate carrying charge to deferrals should be considered.

At the end of the year, the RDM uses the tracker account balance to compute the 2017 RDM adjustment. As is done for the RDM of Xcel Energy, this adjustment would be applied to bills between April 2017 and March 2018. The size of customer surcharges is subject to a 3% soft cap, such that any amount in excess of the cap is retained in the RDM deferral account for recovery the following year. No cap is applied to customer refunds.

The impact on customer bills is shown in the final two rows of each demonstration model. These rows display the adjustment as a percentage of both the 2017 net usage charges (i.e., with the CIP and energy cost components removed) and the 2017 total usage charges. The RDM adjustment is calculated as a percentage applied uniformly to all usage charges in the service basket. For example, in the case of a 2% RDM adjustment, a 10 cents/kWh volumetric charge, and an $8.00/kW demand charge, the adjustment applied to customer bills would be 0.2 cents/kWh and 16 cents/kW, respectively.

[57] Note that the actual net usage-charge revenues are not calculated as the authorized revenue-per-kWh times the total kWh sold (and its demand equivalent) as is done in the RDM of Xcel Energy, since this could create an incentive for the Company to displace sales under low rates to sales under high rates (e.g., from large to small customers, from off-peak to on-peak). To avoid this, the RDM calculation should use actual usage-charge revenue data.

# Appendix

## A.1 Revenue Decoupling Mechanism Models

### Table A1 Residential & Farm: 2016 RDM Calculation

| **TY 2016 Forecasted Usage & Customers** | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service [Rate 101][1] | [A] | kWh | | | | | | | | | | | | | |
| 9.02. Residential Demand Control Service [Rate 241][1] | [B] | kWh | | | | | | | | | | | | | |
| 9.02. Residential Demand Control Service [Rate 241][1] | [C] | kW | | | | | | | | | | | | | |
| 9.03. Farm Service [Rate 361][1] | [D] | kWh | | | | | | | | | | | | | |
| Forecasted Volumes | [E = A+B+D] | kWh | | | | | | | | | | | | | |
| Forecasted Demand | [C] | kW | | | | | | | | | | | | | |
| Forecasted Customers[1] | [F] | Customers | | | | | | | | | | | | | NA |

| **TY 2016 Usage Charges** | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service: Volumetric[2] | [H] | $/kWh | 0.09305 | 0.09305 | 0.09305 | 0.09305 | 0.09305 | 0.11205 | 0.11205 | 0.11205 | 0.11205 | 0.09305 | 0.09305 | 0.09305 | NA |
| 9.02. Residential Demand Control Service: Volumetric[2] | [I] | $/kWh | 0.06324 | 0.06324 | 0.06324 | 0.06324 | 0.06324 | 0.06031 | 0.06031 | 0.06031 | 0.06031 | 0.06324 | 0.06324 | 0.06324 | NA |
| 9.02. Residential Demand Control Service: Demand[2] | [J] | $/kW | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | 8.00000 | NA |
| 9.03. Farm Service: Volumetric[2] | [K] | $/kWh | 0.09005 | 0.09005 | 0.09005 | 0.09005 | 0.09005 | 0.10905 | 0.10905 | 0.10905 | 0.10905 | 0.09005 | 0.09005 | 0.09005 | NA |

| **TY 2016 Forecasted Net Revenues** | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service: Volumetric | [L = A*H] | $ | | | | | | | | | | | | | |
| 9.02. Residential Demand Control Service: Volumetric | [M = B*I] | $ | | | | | | | | | | | | | |
| 9.02. Residential Demand Control Service: Demand | [N = C*J] | $ | | | | | | | | | | | | | |
| 9.03. Farm Service: Volumetric | [O = D*K] | $ | | | | | | | | | | | | | |
| Forecasted Gross Revenues | [P = L+M+N+O] | $ | | | | | | | | | | | | | |
| Adjustment for Conservation Improvement Program (CIP)[3] | [Q = E*(-0.00172)] | $ | | | | | | | | | | | | | |
| Adjustment for Energy Cost Recovery[4] | [R = E*(-0.02464)] | $ | | | | | | | | | | | | | |
| Forecasted Net Revenues | [S = P+Q+R] | $ | | | | | | | | | | | | | |

| **2016 Authorized Net Revenues** | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual Customers[5] | [T] | Customers | | | | | | | | | | | | | NA |
| Authorized Net Revenues per Customer | [U = S/F] | $/Customer | | | | | | | | | | | | | NA |
| Authorized Net Revenues | [V = T*U] | $ | | | | | | | | | | | | | |

| **2016 Actual Net Revenues & RDM Deferral** | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.01. Residential Service: Volumetric[6] | [W] | $ | | | | | | | | | | | | | |
| 9.02. Residential Demand Control Service: Volumetric[6] | [X] | $ | | | | | | | | | | | | | |
| 9.02. Residential Demand Control Service: Demand[6] | [Y] | $ | | | | | | | | | | | | | |
| 9.03. Farm Service: Volumetric[6] | [Z] | $ | | | | | | | | | | | | | |
| Actual Gross Revenues | [AA = W+X+Y+Z] | $ | | | | | | | | | | | | | |
| Actual Volumes[7] | [AB] | kWh | | | | | | | | | | | | | |
| Adjustment for Conservation Improvement Program (CIP) | [AC = AB*(-0.00172)] | $ | | | | | | | | | | | | | |
| Adjustment for Energy Cost Recovery | [AD = AB*(-0.02464)] | $ | | | | | | | | | | | | | |
| Actual Net Revenues | [AE = AA+AC+AD] | $ | | | | | | | | | | | | | |
| RDM Deferral[8] | [AF = V-AE] | $ | | | | | | | | | | | | | |

| **2017 RDM Adjustments** | | Unit | Annual |
|---|---|---|---|
| RDM Deferral Account Balance | [AG] | $ | |
| Forecasted Volumes : April 2017-March 2018[9] | [AH] | kWh | |
| Forecasted Net Revenues: April 2017-March 2018[10] | [AI] | $ | |
| Cap on Customer RDM Surcharges | [AJ = AI*(0.03)] | $ | |
| Total RDM Adjustment: April 2017-March 2018[11] | [AK = min(AG,AJ)] | $ | |
| RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[12] | [AL = AK/AI] | % | |
| RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[12] | [AM = AK/(AI+AH*(0.00172+0.02464))] | % | |

[1] Source: Attachment 2 to IR MN-FE-011_NOT PUBLIC.xlsx. Use of these forecasts for illustrative purposes does not indicate our endorsement of their propriety. The forecasted usage and customers used in the actual RDM should be those approved by the Commission in this proceeding.

[2] The usage charges [H, I, J, & K] shown are those proposed by OTP (Required Information, Volume 2D: Proposed Tariff Sheets - Redlined). Use of these rates for illustrative purposes does not indicate our endorsement of their propriety. The usage charges in the actual RDM should be those approved by the Commission in this proceeding.

[3] The CIP adjustment [Q] utilizes OTP's current CCRC . The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[4] The Energy Cost Recovery adjustment [R] utilizes OTP's current base-rate energy charge. The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[5] Actual Customers [T] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Customers [F].

[6] Actual revenues by rate class [W, X, Y, & Z] are constructed for demonstration purposes. They are based on arbitrary adjustments to TY 2016 billing determinants.

[7] Actual Volumes [AB] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Volumes [F].

[8] A positive RDM deferral [AF] value represents revenues to be recovered from customers, while a negative value represents revenues to be refunded to customers. Following the methodology used for other utilities in Minnesota, no carrying charge is applied.

[9] Forecasted volumes during the RDM adjustment period [AH] is calculated as a weighted average of forecasted 2017 and 2018 volumes (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted volumes in the actual RDM should be those approved by the Commission in a subsequent proceeding.

[10] Forecasted net revenues during the RDM adjustment period [AI] is constructed for demonstration purposes. It is a weighted average of forecasted 2017 and 2018 net revenues, which are approximations based on available data (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted net revenues in the actual RDM should be calculated on the basis of the forecasted billing determinants approved by the Commission in a subsequent proceeding.

[11] A positive RDM adjustment [AK] is a customer surcharge, a negative adjustment a customer refund.

[12] The RDM adjustment is computed as a percentage of volumetric and demand rates, and applied uniformly to all rates in the service basket.

# Table A2 General Service: 2016 RDM Calculation

| TY 2016 Forecasted Usage & Customers | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.01. Small General Service (Metered Secondary) [Rate 404][1] | [A] | kWh | | | | | | | | | | | | | |
| 10.01. Small General Service (Metered Primary) [Rate 405][1] | [B] | kWh | | | | | | | | | | | | | |
| 10.01. Small General Service (Non-Metered) [Rate 408][1] | [C] | kWh | | | | | | | | | | | | | |
| 10.02. General Service (Secondary) [Rate 401][1] | [D] | kWh | | | | | | | | | | | | | |
| 10.02. General Service (Secondary) [Rate 401][1] | [E] | kW | | | | | | | | | | | | | |
| 10.02. General Service (Secondary) [Facilities][1] | [F] | Annual kW | | | | | | | | | | | | | |
| 10.02. General Service (Primary) [Rate 403][1] | [G] | kWh | | | | | | | | | | | | | |
| 10.02. General Service (Primary) [Rate 403][1] | [H] | kW | | | | | | | | | | | | | |
| 10.02. General Service (Primary) [Facilities][1] | [I] | Annual kW | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Declared Peak) [Rate 708][1] | [J] | kWh | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Intermediate) [Rate 709][1] | [K] | kWh | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Intermediate) [Rate 709][1] | [L] | kW | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Off Peak) [Rate 710][1] | [M] | kWh | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use [Facilities][1] | [N] | Annual kW | | | | | | | | | | | | | |
| Forecasted Volumes | [O = A+B+C+D+G+J+K+M] | kWh | | | | | | | | | | | | | |
| Forecasted Demand[2] | [P = E+H+L] | kW | | | | | | | | | | | | | |
| Forecasted Facilities Demand[3] | [Q = F+I+N] | Annual kW | | | | | | | | | | | | | |
| Forecasted Customers[1] | [R] | Customers | | | | | | | | | | | | | NA |

| TY 2016 Usage Charges | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.01. Small General Service (Metered Secondary): Volumetric[4] | [S] | $/kWh | 0.08526 | 0.08526 | 0.08526 | 0.08526 | 0.08526 | 0.10426 | 0.10426 | 0.10426 | 0.10426 | 0.08526 | 0.08526 | 0.08526 | NA |
| 10.01. Small General Service (Metered Primary): Volumetric[4] | [T] | $/kWh | 0.08149 | 0.08149 | 0.08149 | 0.08149 | 0.08149 | 0.10049 | 0.10049 | 0.10049 | 0.10049 | 0.08149 | 0.08149 | 0.08149 | NA |
| 10.01. Small General Service (Non-Metered): Volumetric[4] | [U] | $/kWh | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | 0.08843 | NA |
| 10.02. General Service (Secondary): Volumetric[4] | [V] | $/kWh | 0.08167 | 0.08167 | 0.08167 | 0.08167 | 0.08167 | 0.07788 | 0.07788 | 0.07788 | 0.07788 | 0.08167 | 0.08167 | 0.08167 | NA |
| 10.02. General Service (Secondary): Demand[4] | [W] | $/kW | 1.39000 | 1.39000 | 1.39000 | 1.39000 | 1.39000 | 3.63000 | 3.63000 | 3.63000 | 3.63000 | 1.39000 | 1.39000 | 1.39000 | NA |
| 10.02. General Service (Secondary): Facilities Demand[4] | [X] | $/Annual kW | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | NA |
| 10.02. General Service (Primary): Volumetric[4] | [Y] | $/kWh | 0.07829 | 0.07829 | 0.07829 | 0.07829 | 0.07829 | 0.07527 | 0.07527 | 0.07527 | 0.07527 | 0.07829 | 0.07829 | 0.07829 | NA |
| 10.02. General Service (Primary): Demand[4] | [Z] | $/kW | 1.89000 | 1.89000 | 1.89000 | 1.89000 | 1.89000 | 4.02000 | 4.02000 | 4.02000 | 4.02000 | 1.89000 | 1.89000 | 1.89000 | NA |
| 10.02. General Service (Primary): Facilities Demand[4] | [AA] | $/Annual kW | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | 0.65000 | NA |
| 10.03. General Service-Time of Use (Declared Peak): Volumetric[4] | [AB] | $/kWh | 0.28109 | 0.28109 | 0.28109 | 0.28109 | 0.28109 | 0.53978 | 0.53978 | 0.53978 | 0.53978 | 0.28109 | 0.28109 | 0.28109 | NA |
| 10.03. General Service-Time of Use (Intermediate): Volumetric[4] | [AC] | $/kWh | 0.07478 | 0.07478 | 0.07478 | 0.07478 | 0.07478 | 0.07414 | 0.07414 | 0.07414 | 0.07414 | 0.07478 | 0.07478 | 0.07478 | NA |
| 10.03. General Service-Time of Use (Intermediate): Demand[4] | [AD] | $/kW | 2.69000 | 2.69000 | 2.69000 | 2.69000 | 2.69000 | 2.67000 | 2.67000 | 2.67000 | 2.67000 | 2.69000 | 2.69000 | 2.69000 | NA |
| 10.03. General Service-Time of Use (Off Peak): Volumetric[4] | [AE] | $/kWh | 0.04997 | 0.04997 | 0.04997 | 0.04997 | 0.04997 | 0.04179 | 0.04179 | 0.04179 | 0.04179 | 0.04997 | 0.04997 | 0.04997 | NA |
| 10.03. General Service-Time of Use: Facilities Demand[4] | [AF] | $/Annual kW | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | 0.97000 | NA |

| TY 2016 Forecasted Net Revenues | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.01. Small General Service (Metered Secondary): Volumetric | [AG = A*S] | $ | | | | | | | | | | | | | |
| 10.01. Small General Service (Metered Primary): Volumetric | [AH = B*T} | $ | | | | | | | | | | | | | |
| 10.01. Small General Service (Non-Metered): Volumetric | [AI = C*U] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Secondary): Volumetric | [AJ = D*V] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Secondary): Demand | [AK = E*W] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Secondary): Facilities Demand | [AL = F*X] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Primary): Volumetric | [AM = G*Y] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Primary): Demand | [AN = H*Z] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Primary): Facilities Demand | [AO = I*AA] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Declared Peak): Volumetric | [AP = J*AB] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Intermediate): Volumetric | [AQ = K*AC] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Intermediate): Demand | [AR = L*AD] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Off Peak): Volumetric | [AS = M*AE] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use: Facilities Demand | [AT = N*AF] | $ | | | | | | | | | | | | | |
| Forecasted Gross Revenues | [AU = sum(AG:AT)] | $ | | | | | | | | | | | | | |
| Adjustment for Conservation Improvement Program (CIP)[5] | [AV = O*(-0.00172)] | $ | | | | | | | | | | | | | |
| Adjustment for Energy Cost Recovery[6] | [AW = O*(-0.02464)] | $ | | | | | | | | | | | | | |
| Forecasted Net Revenues | [AX = AU+AV+AW] | $ | | | | | | | | | | | | | |

| 2016 Authorized Net Revenues | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual Customers[7] | [AY] | Customers | | | | | | | | | | | | | NA |
| Authorized Net Revenues per Customer | [AZ = AX/R] | $/Customer | | | | | | | | | | | | | NA |
| Authorized Net Revenues | [BA = AY*AZ] | $ | | | | | | | | | | | | | |

| 2016 Actual Net Revenues & RDM Deferral | | Unit | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.01. Small General Service (Metered Secondary): Volumetric[8] | [BB] | $ | | | | | | | | | | | | | |
| 10.01. Small General Service (Metered Primary): Volumetric[8] | [BC] | $ | | | | | | | | | | | | | |
| 10.01. Small General Service (Non-Metered): Volumetric[8] | [BD] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Secondary): Volumetric[8] | [BE] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Secondary): Demand[8] | [BF] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Secondary): Facilities[8] | [BG] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Primary): Volumetric[8] | [BH] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Primary): Demand[8] | [BI] | $ | | | | | | | | | | | | | |
| 10.02. General Service (Primary): Facilities[8] | [BJ] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Declared Peak): Volumetric[8] | [BK] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Intermediate): Volumetric[8] | [BL] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Intermediate): Demand[8] | [BM] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use (Off Peak): Volumetric[8] | [BN] | $ | | | | | | | | | | | | | |
| 10.03. General Service-Time of Use: Facilities[8] | [BO] | $ | | | | | | | | | | | | | |
| Actual Gross Revenues | [BP = sum(BB:BO)] | $ | | | | | | | | | | | | | |
| Actual Volumes[9] | [BQ] | kWh | | | | | | | | | | | | | |
| Adjustment for Conservation Improvement Program (CIP) | [BR = BQ*(-0.00172)] | $ | | | | | | | | | | | | | |
| Adjustment for Energy Cost Recovery | [BS = BQ*(-0.02464)] | $ | | | | | | | | | | | | | |
| Actual Net Revenues | [BT = BP+BR+BS] | $ | | | | | | | | | | | | | |
| RDM Deferral[10] | [BU = BA-BT] | $ | | | | | | | | | | | | | |

| 2017 RDM Adjustments | | Unit | Annual |
|---|---|---|---|
| RDM Deferral Account Balance | [BV] | $ | |
| Forecasted Volumes : April 2017-March 2018[11] | [BW] | kWh | |
| Forecasted Net Revenues: April 2017-March 2018[12] | [BX] | $ | |
| Cap on Customer RDM Surcharges | [BY = BX*(0.03)] | $ | |
| Total RDM Adjustment: April 2017-March 2018[13] | [BZ = min(BV,BY)] | $ | |
| RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[14] | [CA = BZ/BX] | % | |
| RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[14] | [CB = BZ/(BX+BW* (0.00172+0.02464))] | % | |

[1] Source: Attachment 2 to IR MN-FE-011_NOT PUBLIC.xlsx. Use of these forecasts for illustrative purposes does not indicate our endorsement of their propriety. The forecasted usage and customers used in the actual RDM should be those approved by the Commission in this proceeding.

[2] Billing demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use). For simplicity, these are summed to obtain the Forecasted Demand [P]. Forecasted Demand is not used in subsequent RDM calculations.

[3] Facilities charge demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use). For simplicity, these are summed to obtain the Forecasted Facilities Demand [Q]. Forecasted Facilities Demand is not used in subsequent RDM calculations.

[4] The usage charges [S-AF] shown are those proposed by OTP (Required Information, Volume 2D: Proposed Tariff Sheets - Redlined). Use of these rates for illustrative purposes does not indicate our endorsement of their propriety. The usage charges in the actual RDM should be those approved by the Commission in this proceeding.

[5] The CIP adjustment [AV] utilizes OTP's current CCRC . The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[6] The Energy Cost Recovery adjustment [AW] utilizes OTP's current base-rate energy charge. The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[7] Actual Customers [AY] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Customers [R].

[8] Actual revenues by rate class [BB-BO] are constructed for demonstration purposes. They are based on arbitrary adjustments to TY 2016 billing determinants.

[9] Actual Volumes [BQ] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Volumes [O].

[10] A positive RDM deferral [BU] value represents revenues to be recovered from customers, while a negative value represents revenues to be refunded to customers. Following the methodology used for other utilities in Minnesota, no carrying charge is applied.

[11] Forecasted volumes during the RDM adjustment period [BW] is calculated as a weighted average of forecasted 2017 and 2018 volumes (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted volumes in the actual RDM should be those approved by the Commission in a subsequent proceeding.

[12] Forecasted net revenues during the RDM adjustment period [BX] is constructed for demonstration purposes. It is a weighted average of forecasted 2017 and 2018 net revenues, which are approximations based on available data (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted net revenues in the actual RDM should be calculated on the basis of the forecasted billing determinants approved by the Commission in a subsequent proceeding.

[13] A positive positive RDM adjustment [BZ] is a customer surcharge, a negative adjustment a customer refund.

[14] The RDM adjustment is computed as a percentage of volumetric, demand and facilities demand rates, and applied uniformly to all rates in the service basket.

## A.2 Revenue Decoupling Tariff

*Minnesota Public Utilities* ***Commission***
Section **13.__**
ELECTRIC RATE SCHEDULE
**Revenue Decoupling Mechanism Rider**

Fergus Falls, Minnesota

Page 1 of 2
*Original*

**REVENUE DECOUPLING MECHANISM (RDM) RIDER**

| DESCRIPTION | RATE CODE |
|---|---|
| Revenue Decoupling Mechanism Rider | 32-XXX |

**RULES AND REGULATIONS:** Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

**APPLICATION OF RIDER:** This rider is applicable to bills for electric service provided under the Company's retail rate schedules in Sections 9.01 (Residential), 9.02 (Residential Demand Control), 9.03 (Farm), 10.01 (Small General Service), 10.02 (General Service), and 10.03 (General Service - Time of Use).

**RDM ADJUSTMENT:** There shall be included on the monthly bills for each of these Minnesota rate schedules a Revenue Decoupling Mechanism (RDM) Rider. Its purpose is to adjust the Company's actual per-customer revenues from usage charges to the level needed to recover its authorized revenue requirement, preventing either under- or over-recovery. The adjustment will require either a surcharge or refund. The adjustment shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service, and is applicable in addition to all charges for service being taken under the Company's standard rate schedules.

The adjustment shall be calculated separately for two Service Baskets.

1. **Residential & Farm:** Rate Schedules 9.01 (Residential Service), 9.02 (Residential Demand Control Service), and 9.03 (Farm Service).

2. **General Service:** Rate Schedules 10.01 (Small General Service), 10.02 (General Service), and 10.03 (General Service - Time of Use).

Usage by customers in one Service Basket shall not affect the adjustment applied to another Service Basket.

For purposes of this section the following definitions apply:

**Net Usage Charges (NUC):** The dollar amount billed per kWh of electric consumption, any kW of billing demand, and any kW of facilities charge demand, excluding the 2.4640¢ per kWh base-rate energy charge (Section 13.01) and 0.172¢ per kWh CCRC (Section 13.02).

MINNESOTA PUBLIC
UTILITIES COMMISSION
Approved:
Docket No. E017/GR-15-1033

EFFECTIVE with bills rendered
on and after

in Minnesota

*Minnesota Public Utilities* ***Commission***
Section **13.__**
ELECTRIC RATE SCHEDULE
**Revenue Decoupling Mechanism Rider**

Fergus Falls, Minnesota

Page 2 of 2
*Original*

**RDM Factor:** The number multiplied by the NUC to compute the RDM adjustment.

**RDM Deferral Account:** The account used to track variances between the Company's authorized NUC revenues and actual NUC revenues each month for a given Service Basket, deferring them for use in the next RDM adjustment calculation. The authorized NUC are equal to the average per-customer NUC revenues approved for that month by the Minnesota Public Utilities Commission (Commission) in the Company's last rate case, multiplied by the actual number of customers that month.

**Monthly RDM Deferral:** The amount placed in the RDM Deferral Account in a given month.

**Annual RDM Deferral:** The balance in the RDM Deferral Account on December 31. This balance is equal to the sum of the 12 Monthly RDM Deferrals plus any under- or over-recovery of the previous Annual RDM Deferral.

Each year during the term of this rider the Company shall compute an RDM Factor for each Service Basket. The factor is based on the balance in the RDM Deferral Account on December 31 and the total forecasted NUC for April 1 through March 31 of the following year:

RDM Factor = Annual RDM Deferral / Forecasted NUC

A positive RDM Factor yields a customer surcharge, and a negative RDM Factor a customer refund. Surcharges shall be capped at 3% of the total forecasted NUC for each Service Basket, unless the Company is granted approval from the Commission to recover revenues in excess of the cap. Customer refunds shall not be capped. Any under- or over-recovery of the Annual RDM Deferral will be included in the RDM Deferral Account for the applicable Service Basket, and reflected in the following year's RDM Factor.

The RDM Factor is multiplied by the customer's NUC in a given month to calculate the customer's RDM adjustment in that month.

| RDM FACTOR | | |
|---|---|---|
| **Residential & Farm** | **(a)** | 0.0000 |
| **General Service** | **(b)** | 0.0000 |

(a) Rate Schedules 9.01 Residential Service, 9.02 Residential Demand Control Service, and 9.03 Farm Service.
(b) Rate Schedules 10.01 Small General Service, Rate Schedule 10.02 General Service, and Rate Schedule 10.03 General Service - Time of Use.

MINNESOTA PUBLIC
UTILITIES COMMISSION
Approved:
Docket No. E017/GR-15-1033

EFFECTIVE with bills rendered
on and after

in Minnesota

# Bibliography

American Gas Association (2009), *Natural Gas Rate Roundup*, May, p. 3.

e21 Initiative (2014), *Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota*, December.

Gilleo, A., Nowak, S., Kelly, M., Vaidyanathan, S., Shoemaker, M., Chittum, A., & Bailey, T. (2015), *The 2015 State Energy Efficiency Scorecard,* Report U1509, American Council for an Energy-Efficient Economy, October.

Hayes, S., Nadel, S., Kushler, M. and York, D. (2011), *Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency,* Report U111, American Council for an Energy-Efficient Economy, January.

Institute for Electric Innovation (2014), *State Electric Efficiency Regulatory Frameworks,* The Edison Foundation, December.

Lowry, M., Makos, M., and Waschbusch, G. (2015), *Alternative Regulation for Emerging Utility Challenges: 2015 Update,* Edison Electric Institute, November.

Lowry, Mark Newton and Woolf, T. (2016), *Performance-Based Regulation for a High Distributed Energy Resource Future*, Lawrence Berkeley National Laboratory, January 2016.

Morgan, P. (2013), *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations,* Graceful Systems LLC, May.

Nadel, S., and Herndon, G. (2014). *The Future of the Utility Industry and the Role of Energy Efficiency,* Report U1404, American Council for an Energy-Efficient Economy, June.

National Action Plan for Energy Efficiency (2007), *Aligning Utility Incentives with Investment in Energy Efficiency*, Prepared by Val R. Jensen, ICF International.

Nissen, W., and Williams, S. (2016). *The Link Between Decoupling and Success in Utility-led Energy Efficiency*, Electricity Journal, Vol 29, Issue 2., March.

Nowak, S., Baatz, B., Gilleo, A., Kushler, M., Molina, M. and York, D. (2015), *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, Report U1504, American Council for an Energy-Efficient Economy, May.

Ofgem (2012), *Strategy Consultation for the RIIO-ED1 Electricity Distribution Price Control: Outputs, Incentives and Innovation. Supplementary Annex to RIIO-ED1 Overview Paper*. Office of Gas and Electricity Markets.

Regulatory Assistance Project (2011), *Revenue Regulation and Decoupling: A Guide to Theory and Application,* June.

Whited, M., Woolf, T., and Napoleon, A. (2015), *Utility Performance Incentive Mechanisms: A Handbook for Regulators,* Synapse Energy Economics, March.

## CERTIFICATE OF SERVICE

**RE: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota**
**Docket No. E017/GR-15-1033**

I, Jana Hrdlicka, hereby certify that I have this day served a copy of the following, or a summary thereof, on Daniel P. Wolf and Sharon Ferguson by e-filing, and to the Office of Attorney General – Antitrust & Utilities Division and all other persons on the attached service lists by electronic service or by First Class mail.

**Otter Tail Power Company**
**Compliance Filing - Decoupling Report**

Dated this **30th** day of **March, 2018**

*/s/ JANA HRDLICKA*

Jana Hrdlicka
Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8879

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Christopher | Anderson | canderson@allete.com | Minnesota Power | 30 W Superior St<br><br>Duluth,<br>MN<br>558022191 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| William A. | Blazar | bblazar@mnchamber.com | Minnesota Chamber Of Commerce | Suite 1500<br>400 Robert Street North<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Tom | Boyko | tboyko@eastriver.coop | East River Electric Power Coop. | 211 S. Harth Ave<br><br>Madison,<br>SD<br>57042 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Ray | Choquette | rchoquette@agp.com | Ag Processing Inc. | 12700 West Dodge Road<br>PO Box 2047<br>Omaha,<br>NE<br>68103-2047 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Generic Notice | Commerce Attorneys | commerce.attorneys@ag.state.mn.us | Office of the Attorney General-DOC | 445 Minnesota Street Suite 1800<br><br>St. Paul,<br>MN<br>55101 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Joseph | Dammel | joseph.dammel@ag.state.mn.us | Office of the Attorney General-RUD | Bremer Tower, Suite 1400<br>445 Minnesota Street<br>St. Paul,<br>MN<br>55101-2131 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| William T | Davis | N/A | - | 23456 Garland Ln<br><br>Battle Lake,<br>MN<br>56515-9665 | Paper Service | No | OFF_SL_15-1033_Official Service List |
| Ian | Dobson | residential.utilities@ag.state.mn.us | Office of the Attorney General-RUD | 1400 BRM Tower<br>445 Minnesota St<br>St. Paul,<br>MN<br>551012130 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Charles | Drayton | charles.drayton@enbridge.com | Enbridge Energy Company, Inc. | 7701 France Ave S Ste 600<br><br>Edina,<br>MN<br>55435 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| James C. | Erickson | jericksonkbc@gmail.com | Kelly Bay Consulting | 17 Quechee St<br><br>Superior,<br>WI<br>54880-4421 | Electronic Service | No | OFF_SL_15-1033_Official Service List |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Sharon | Ferguson | sharon.ferguson@state.mn.us | Department of Commerce | 85 7th Place E Ste 280<br><br>Saint Paul,<br>MN<br>551012198 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Edward | Garvey | garveyed@aol.com | Residence | 32 Lawton St<br><br>Saint Paul,<br>MN<br>55102 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Bruce | Gerhardson | bgerhardson@otpco.com | Otter Tail Power Company | PO Box 496<br>215 S Cascade St<br>Fergus Falls,<br>MN<br>565380496 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Dan | Harmelink | Dan.Harmelink@woodsfuller.com | Woods, Fuller, Shultz & Smith P.C. | 300 S Phillips Ave Ste 300<br>PO Box 5027<br>Sioux Falls,<br>SD<br>57117-5027 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Kimberly | Hellwig | kimberly.hellwig@stoel.com | Stoel Rives LLP | 33 South Sixth Street<br>Suite 4200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Annete | Henkel | mui@mnutilityinvestors.org | Minnesota Utility Investors | 413 Wacouta Street<br>#230<br>St.Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Shane | Henriksen | shane.henriksen@enbridge.com | Enbridge Energy Company, Inc. | 1409 Hammond Ave FL 2<br><br>Superior,<br>WI<br>54880 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Linda | Jensen | linda.s.jensen@ag.state.mn.us | Office of the Attorney General-DOC | 1800 BRM Tower 445 Minnesota Street<br><br>St. Paul,<br>MN<br>551012134 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Richard | Johnson | Rick.Johnson@lawmoss.com | Moss & Barnett | 150 S. 5th Street<br>Suite 1200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Joel W. | Kanvik | joel.kanvik@enbridge.com | Enbridge Energy LLC | 4628 Mike Colalillo Dr<br><br>Duluth,<br>MN<br>55807 | Electronic Service | No | OFF_SL_15-1033_Official Service List |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Bill | Lachowitzer | blachowitzer@ibewlocal949.org | IBEW Local Union 949 | 12908 Nicollet Ave S<br>Burnsville,<br>MN<br>55337-3527 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| James D. | Larson | james.larson@avantenergy.com | Avant Energy Services | 220 S 6th St Ste 1300<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Douglas | Larson | dlarson@dakotaelectric.com | Dakota Electric Association | 4300 220th St W<br>Farmington,<br>MN<br>55024 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Eric | Lipman | eric.lipman@state.mn.us | Office of Administrative Hearings | PO Box 64620<br>St. Paul,<br>MN<br>551640620 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Peter | Madsen | peter.madsen@ag.state.mn.us | Office of the Attorney General-DOC | Bremer Tower, Suite 1800<br>445 Minnesota Street<br>St. Paul,<br>Minnesota<br>55101 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E<br>St. Paul,<br>MN<br>55106 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Joseph | Meyer | joseph.meyer@ag.state.mn.us | Office of the Attorney General-RUD | Bremer Tower, Suite 1400<br>445 Minnesota Street<br>St Paul,<br>MN<br>55101-2131 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Tom | Micheletti | tommicheletti@excelsiorenergy.com | Excelsior Energy Inc. | 225 S 6th St Ste 2560<br>Minneapolis,<br>MN<br>55402-4638 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Andrew | Moratzka | andrew.moratzka@stoel.com | Stoel Rives LLP | 33 South Sixth St Ste 4200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Ben | Passer | Passer@fresh-energy.org | Fresh Energy | 408 St. Peter Street Ste 220<br>Saint Paul,<br>MN<br>55102 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| David G. | Prazak | dprazak@otpco.com | Otter Tail Power Company | P.O. Box 496<br>215 South Cascade Street<br>Fergus Falls,<br>MN<br>565380496 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Rate Case Inbox | Rate Case Inbox | mnratecase@otpco.com | Otter Tail | N/A | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Richard | Savelkoul | rsavelkoul@martinsquires.com | Martin & Squires, P.A. | 332 Minnesota Street Ste W2750<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Larry L. | Schedin | Larry@LLSResources.com | LLS Resources, LLC | 332 Minnesota St, Ste W1390<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Robert H. | Schulte | rhs@schulteassociates.com | Schulte Associates LLC | 1742 Patriot Rd<br>Northfield,<br>MN<br>55057 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Janet | Shaddix Elling | jshaddix@janetshaddix.com | Shaddix And Associates | 7400 Lyndale Ave S Ste 190<br>Richfield,<br>MN<br>55423 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Mrg | Simon | mrgsimon@mrenergy.com | Missouri River Energy Services | 3724 W. Avera Drive<br>P.O. Box 88920<br>Sioux Falls,<br>SD<br>571098920 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| William | Taylor | bill.taylor@williamgtaylor.com | Taylor Law Firm | 2921 E 57th St<br>PO Box 10<br>,<br>Sioux Falls<br>SD | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Pat | Treseler | pat.jcplaw@comcast.net | Paulson Law Office LTD | 4445 W 77th Street<br>Suite 224<br>Edina,<br>MN<br>55435 | Electronic Service | No | OFF_SL_15-1033_Official Service List |
| Cam | Winton | cwinton@mnchamber.com | Minnesota Chamber of Commerce | 400 Robert Street North<br>Suite 1500<br>St. Paul,<br>Minnesota<br>55101 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Daniel P | Wolf | dan.wolf@state.mn.us | Public Utilities Commission | 121 7th Place East<br>Suite 350<br>St. Paul,<br>MN<br>551012147 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |
| Patrick | Zomer | Patrick.Zomer@lawmoss.com | Moss & Barnett a Professional Association | 150 S. 5th Street, #1200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | Yes | OFF_SL_15-1033_Official Service List |