Direct Testimony and Schedules
Christopher J. Barthol

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 Gas Service in Minnesota

Docket No. G002/GR-21-678
Exhibit___(CJB-1)

Class Cost of Service Study and Decoupling

November 1, 2021

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Principal Pricing Analyst for Northern States Power Company (NSP, Xcel Energy, or the Company), a wholly owned subsidiary of Xcel Energy Inc.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include 10 years of regulatory experience in the areas of rate design and class cost of service. I have served as a witness before the North Dakota Public Service Commission. I have a Bachelor of Arts in Economics from Saint Cloud State University and a Master of Science in Agricultural Economics from Purdue University. A detailed statement of my qualifications and experience is provided in Exhibit___(CJB-1), Schedule 1.

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

A. The purpose of my testimony is to present the Company's Class Cost of Service Study (CCOSS) and proposed Revenue Decoupling Mechanism (RDM).

Q. PLEASE SUMMARIZE NSP'S CCOSS PROPOSAL.

A. The CCOSS is done on a forecasted 2022 calendar year embedded cost basis, which, based on cost-causation principles, functionalizes, classifies, and allocates budgeted plant and expenses in the test year. Other than the refinement of the calculation of certain allocators, the Company is not proposing any significant changes to the CCOSS methodology approved by the Minnesota Public Utilities Commission (Commission) in the Company's last natural gas rate case, Docket No. G002/GR-09-1153. Below, I will describe the modifications to the class allocations and the rationale for the adjustments, detail the class allocations indicated by the CCOSS, and discuss the results of the CCOSS.

II. CCOSS OVERVIEW

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I describe the purpose of the CCOSS that was conducted, and the Company's objectives in conducting the CCOSS. I also summarize the results of the CCOSS.

A. CCOSS Purpose

Q. WHAT IS THE PURPOSE OF A CCOSS?

A. The CCOSS allocates the total cost of providing utility service (also referred to as the Company's revenue requirement) to our various customer classes in a way that reflects the engineering and operating characteristics of the natural gas utility system, and hence each class's contribution to the costs of providing service. The primary objective of the CCOSS is to determine the total cost of service for each customer class, which, given the characteristics of gas utility costs, includes the costs associated with investment in plant as well as operating and maintenance expenses. Another key objective of the CCOSS is to develop class cost allocation factors that accurately reflect cost causation. Results from the CCOSS serve as a guide for evaluating and developing the Company's rate structure, as discussed in more detail by Company witness Ms. Michelle M. Terwilliger.

Q. WHAT ARE THE COMPANY'S OBJECTIVES WHEN DEVELOPING ITS CCOSS?

A. The Company's CCOSS objectives are:

1. Properly reflect all the costs and revenues that have been identified in the Company's Minnesota Jurisdictional Cost of Service Study (JCOSS);
2. Develop allocators that can be accurately determined and calculated with a reasonable amount of effort to properly assign those costs among the various customer classes and the three main billing classifications – customer, demand, and commodity; and,
3. Use allocators that are consistent across the Company's jurisdictions.

B. CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE PROPOSED CCOSS.

A. The classes in the CCOSS include:

- Residential (Res);
- Commercial (Com) – Small and Large Commercial customers;
- Demand – Small and Large Demand-Billed customers;
- Interruptible (Interrupt) – Small, Medium, and Large Interruptible customers;
- Transportation (Tran) – Firm, Interruptible, and Negotiated Transportation customers; and
- Generation (Gener) – Electric Generation customers who take service on our sales or transportation service tariffs noted above.

Table 1 below shows a summary of the CCOSS results at the major class level. A more detailed summary is provided in Exhibit___(CJB-1), Schedule 3. These results indicate the level of rate increase necessary for each class of service to produce equal rates of return from each class.

Table 1

Summary of Class Cost of Service Study ($000)

Item	Res	Com	Demand	Interrupt	Tran	Gener	Total
CCOSS Results	$356,746	$148,947	$16,101	$36,712	$4,681	$13,457	$576,645
Present Revenue	$316,793	$153,749	$17,962	$40,149	$5,248	$7,115	$541,016
Revenue Deficiency	$39,954	-$4,802	-$1,861	-$3,437	-$567	$6,342	$35,629
Deficiency/Pres	12.61%	-3.12%	-10.36%	-8.56%	-10.80%	89.13%	6.59%

Q. PLEASE EXPLAIN THE CCOSS RESULTS.

A. The CCOSS indicates a cost-of-service increase of 12.61 percent for Residential Firm service and 89.13 percent for Generation customers. The CCOSS indicates a decrease in the costs of service of 3.12 percent for Commercial customers, 10.36 percent for Demand customers, 8.56 percent for Interruptible customers, and 10.80 percent for Transport customers. As I mentioned above, the CCOSS results serve as a guide for developing revenue apportionment and rate design, as discussed in more detail by Company witness Ms. Michelle M. Terwilliger.

Q. HOW DO THE CCOSS RESULTS COMPARE TO THOSE IN THE COMPANY'S LAST NATURAL GAS RATE CASE (DOCKET NO. G002/GR-09-1153)?

A. The CCOSS results are similar to the results in the Company's last general rate case in that the Residential and Generation classes' rates are below cost while the Commercial, Demand, Interruptible, and Transport classes are above cost.

Since our class allocation methodology is similar to the last case, and the approved revenue apportionment in the last case resulted in Residential rates under the cost of service and other classes above the cost of service, this result is reasonable. It also should be noted that some customers in the Generation class take service under the flexible rate provisions of our tariffs. Their rates are designed to cover at least incremental costs and not the embedded costs associated with the CCOSS.

Q. HOW DO THE CURRENT PRIMARY ALLOCATORS IN THE CCOSS FOR THIS CASE COMPARE WITH THE PRIMARY ALLOCATORS FROM THE CCOSS USED IN THE LAST NATURAL GAS RATE CASE?

A. The Company is utilizing the same primary allocators as these allocators continue to be the most appropriate class allocators for assigning costs that vary by customer count, demand (design day), sales, or distribution investment. Table 2 provides a comparison of the primary allocators evaluating their current percentages versus those in the last natural gas rate case. While there are modest changes in these allocators, there are not material changes to the percentages themselves. Therefore, it is reasonable that the CCOSS results are similar to those from our last rate case. I will later explain in my testimony how these allocators were developed for this CCOSS.

Table 2

Allocator Comparison (2022 TY vs. 2010 TY)

Allocator	Res	Com	Demand	Interrupt	Tran	Gener
Customers – 2022	92.40%	7.51%	0.03%	0.06%	0.01%	0.00%
Customers – 2010	92.26%	7.59%	0.03%	0.12%	0.00%	0.00%
Design Day – 2022	52.55%	31.01%	3.21%	0.00%	0.41%	12.81%
Design Day – 2010	54.70%	26.78%	2.47%	0.00%	0.27%	15.77%
Mains, Overall – 2022	76.34%	15.19%	1.11%	1.20%	1.72%	4.43%
Mains, Overall – 2010	80.55%	12.61%	0.69%	1.21%	0.64%	4.31%
Service Study – 2022	84.76%	14.63%	0.16%	0.41%	0.03%	0.01%
Service Study – 2010	82.73%	15.43%	0.23%	1.55%	0.04%	0.02%
Meter & Regul – 2022	79.85%	18.10%	0.62%	1.24%	0.15%	0.04%
Meter & Regul – 2010	77.53%	19.89%	0.51%	1.97%	0.07%	0.04%
Sales, W/o Transp – 2022	52.32%	30.91%	4.02%	12.72%	0.00%	0.03%
Sales, W/o Transp – 2010	51.80%	26.80%	3.41%	17.32%	0.00%	0.67%
Sales, W/ Transp – 2022	35.04%	20.70%	2.69%	8.52%	12.04%	21.01%
Sales, W/ Transp – 2010	39.57%	20.47%	2.60%	13.23%	6.99%	17.13%

III. CCOSS PREPARATION

A. Preparation of a CCOSS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I provide an overview of the preparation of the CCOSS and describe the allocators used in the CCOSS.

Q. WHAT TYPE OF CCOSS WAS PREPARED?

A. The CCOSS presented in this case is a fully-distributed, embedded CCOSS. The CCOSS is "fully-distributed" in that it allocates plant and operating expenses based on the manner in which they are incurred. The CCOSS is considered "embedded" because it functionalizes, classifies, and allocates budgeted plant and expenses in the test year.

Q. WHAT ARE THE STEPS FOR PREPARING A CCOSS?

A. In general, preparing a CCOSS involves five major steps:

First, costs are identified by function, such as production, storage, transmission, and distribution. Costs are then separated by state jurisdiction – in this case, between the Minnesota and North Dakota retail gas jurisdictions. This step is supported in the Direct Testimony and Schedules of Company witness Mr. Benjamin C. Halama.

Second, costs that can be directly attributed to specific customer classes are directly assigned to their respective classes.

Third, the remaining unassigned costs are allocated among the customer classes by an appropriate allocation method. An external allocator is an allocator that takes information generated separate from the CCOSS, such as a class's sales or customer counts. Internal allocators are based on combinations of costs already allocated to the classes using external allocators. For example, the cost of distribution mains is allocated to class using an internal allocator that performs calculations relying on a class's contribution to plant in service associated with distribution mains.

Fourth, the costs for each class are then classified as capacity (demand), customer, and commodity (gas) based on whether the costs are driven by Design Day demand, number of customers, or usage. This step guides rate design within a class, as opposed to between classes. For instance, customer-driven costs, like natural gas meters, are not impacted by variations in gas usage or contribution to overall demand on a Design Day. Rather, such costs are affected by changes in the number of customers; the more customers the Company has, the more natural gas meters are needed.

Finally, the cost of serving each class is compared to the test year revenues generated by each class at current rates to determine the adjustment in revenues that is necessary for each class to recover its costs of service.

A guide to the CCOSS study is provided in Exhibit___(CJB-1), Schedule 2. The guide provides information on individual studies conducted for the purpose of developing allocators within the CCOSS study, descriptions of how calculations within the CCOSS are performed, and an index of external and internal allocators and their definitions.

B. External Allocators

Q. WHAT ARE EXTERNAL ALLOCATORS?

A. External allocators are calculated with data outside the CCOSS model (e.g. Design Day demands, metering and customer service-related cost ratios). There are three types of external allocators: Capacity (Demand), Commodity (Energy), and Customer-related allocators.

Q. WHAT DISTRIBUTION PLANT STUDIES WERE CONDUCTED TO DEVELOP EXTERNAL ALLOCATORS WITHIN THE CCOSS?

A. The following is a list of studies that were conducted to develop the external allocators:

- Minimum System
- Meter and Regulator Study
- Service Study

- Record & Collections Study
- Customer Information Study
- Uncollectibles Study
- Late Fee Study

A full description of all seven studies is provided in Exhibit___(CJB-1), Schedule 2. I describe minor refinements to the Minimum System, Uncollectibles, and Late Fee studies in my testimony below.

Q. WHAT IS A MINIMUM SYSTEM STUDY?

A. A Minimum System Study identifies the portion of distribution plant associated with basic connectivity between the utility and the customer. The Minimum System Study determines the breakdown of costs that are customer-related (and therefore allocated with a customer-related allocator), versus those costs associated with capacity (and allocated with a demand-related allocator). As in the last rate case, the Company conducted a Minimum-Sized Plant Study that identifies the smallest and most common distribution mains in a utility's system, identifies the cost per foot of the smallest and most common main, and applies that cost per foot to every main in the distribution system to derive the cost of a "minimum system." The cost of the minimum system is divided by the total costs of actual distribution mains in the system to derive the portion of distribution costs that are customer related. The remaining costs are split into average and excess capacity costs, which I discuss later in my testimony.

Q. WHAT METHODOLOGY ARE YOU PROPOSING FOR THE MINIMUM SYSTEM STUDY?

A. I am proposing a minimum-sized plant study using the same methodology that was used in the Company's last natural gas rate case, with a minor modification to the application of the Handy-Whitman index for the escalation of the cost of gas mains. The Handy-Whitman index is utilized to escalate historical costs to the present. The Minimum System Study is provided in Exhibit___(CJB-1), Schedule 4.

Q. WHAT OTHER KEY EXTERNAL ALLOCATORS ARE INCLUDED IN THE CCOSS?

A. The remaining external allocators are the Design Day Demand and Sales allocators. A full description of these is provided in Exhibit___(CJB-1), Schedule 2.

C. Internal Allocators

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss internal allocators used in the CCOSS. Internal allocators are based on a combination of costs already allocated to the classes with external allocators. I distinguish between primary internal allocators and new internal allocators, which were developed since the last natural gas rate case.

Q. WHAT ARE THE PRIMARY INTERNAL ALLOCATORS?

A. The primary internal allocators include a) Average and Peak, b) Mains, Overall, and c) Production-Storage-Transmission-Distribution. A full description of these is provided in Exhibit___(CJB-1), Schedule 2.

Q. ARE THERE ANY NEW INTERNAL ALLOCATORS IN THE CCOSS?

A. Yes. I've created a Labor Without A&G Allocator.

Q. PLEASE EXPLAIN THE LABOR WITHOUT A&G ALLOCATOR.

A. To create an allocator for A&G labor costs, we combined the labor expenses related to customer accounting, customer service and information, distribution, production, sales, and transmission and labeled it "Labor Without A&G Allocator." The A&G labor costs are excluded from this allocator in order to avoid a circular reference in the CCOSS model.

D. Changes and Improvements to CCOSS

Q. IS THE COMPANY'S CCOSS CONSISTENT WITH ITS PAST PRACTICE IN MINNESOTA?

A. Yes. The CCOSS conducted for this case is very similar to that performed by the Company in its last natural gas rate case (Docket No. G002/GR-09-1153). Except for a few minor improvements to the uncollectibles study, late fee study, and direct assignments of cost to the Transport Generation class, most of the allocation factors used in our previous rate case were used in this CCOSS. These improvements do not materially affect the CCOSS results. The various allocation percentages have been updated to reflect forecasted 2022 data on customers, sales, Design Day inputs, and other relevant items. The detailed CCOSS is included with Volume 3, Required Information, as part of the Company's rate case application.

Q. HOW DID YOU DETERMINE THE APPROPRIATE ALLOCATION OF EXPENSES FOR UNCOLLECTIBLES?

A. I performed an uncollectibles study to allocate expenses associated with FERC Account 904.

Q. WHAT IS FERC ACCOUNT 904, AS DEFINED BY THE UNIFORM SYSTEM OF ACCOUNTS?

A. FERC Account 904 is associated with the dollar amounts sufficient to provide for losses from uncollectible utility revenues.

Q. HOW DO YOU PERFORM THE UNCOLLECTIBLES STUDY?

A. The uncollectibles study consists of gathering information on customer debtor numbers, net uncollectibles (bad debt less recoveries), and classes associated with each debtor number to determine the net uncollectibles for each class. The net uncollectibles for each class are utilized to calculate the allocator.

Q. HOW WERE EXPENSES ASSOCIATED WITH FERC ACCOUNT 904 ALLOCATED IN THE LAST GENERAL NATURAL GAS RATE CASE (Docket No. G002/GR-09-1153)?

A. These expenses were simply allocated based on a weighted number of customers in each class.

Q. WHY DID YOU CONDUCT AN UNCOLLECTIBLES STUDY INSTEAD OF ALLOCATING THESE EXPENSES BASED ON THE NUMBER OF CUSTOMERS IN EACH CLASS?

A. With the uncollectibles study, I am calculating the actual net uncollectibles that were incurred for each class. This provides more accurate cost allocation than simply allocating these expenses based on a weighted number of customers in each class.

Q. HOW DID YOU DETERMINE THE PROPER REVENUE ALLOCATOR FOR LATE FEES?

A. I determined the appropriate allocator for late fee revenue by using the late payment study.

Q. PLEASE EXPLAIN THE LATE PAYMENT STUDY.

A. The late payment study follows the same process as the uncollectibles study, as it determines customer late fees by class. The late fees by class are used to derive the late fee revenue allocator and assign late payment revenues to each customer class.

Q. PLEASE EXPLAIN THE DIRECT ASSIGNMENT OF COSTS TO THE TRANSPORT GENERATION CLASS.

A. I was able to directly assign plant and related expenses associated with transmission mains that serve two of our Transport Generation customers. I therefore did not allocate costs to this class, such as production, storage, and distribution costs. The remaining transmission plant and expenses that are not directly assigned are allocated to all classes via the average and peak allocator.

IV. DECOUPLING OVERVIEW

Q. WHAT IS DECOUPLING?

A. Decoupling is a rate adjustment mechanism "designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency."[1] Typically, decoupling mechanisms accomplish this by means of an adjustment (either a credit or a surcharge) that trues up the revenues received by a utility to the authorized test year revenue requirement set by a commission in a rate case. In general, decoupling is used as a mechanism to better align the utility's interests with public policy goals (such as the promotion of energy efficiency), thus making it

[1] Minn. Stat. § 216B.2412, subd 1.

easier to achieve those goals. It can also ensure the utility is neither rewarded nor penalized for factors that affect energy consumption that are outside its control, such as unusual weather.

Q. WHAT ARE PUBLIC POLICY REASONS SUPPORTING DECOUPLING?

A. When natural gas sales increase, so do potential revenues. This may create an incentive for a gas utility to maximize sales. By removing the link between energy sales and utility revenue, a decoupling mechanism can enable utilities to promote energy efficiency "systematically and aggressively"[2] without concern about the impact of reduced sales on their ability to recover fixed costs. As Minnesota's policy framework moves beyond simply energy efficiency and works specifically to reduce the use of geologically-sourced gas[3] – increasingly, through the activity of the gas utilities themselves – decoupling is an important tool that allows utilities to support such efforts with less concern about the impact on revenue. At the same time, by supporting the recovery of fixed costs, decoupling helps to ensure that critical energy infrastructure is available at times of peak need, even if overall throughput declines.

Q. PLEASE ELABORATE ON HOW DECOUPLING CAN FURTHER POLICY GOALS, SPECIFICALLY WITH REGARD TO THE EXAMPLES YOU LIST ABOVE?

A. The Company recognizes that conservation is beneficial, and the primary goal of decoupling is to remove the disincentive to promote conservation. This disincentive to promote conservation may be significant if there is a large gap between rate cases, as the cumulative sales reduction grows over time. Table 3

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[2] Minn. Stat. § 216B.2401

[3] Minn. Stat. § 216B.2427, subd. 2(10)

shows the gas conservation improvement program (CIP) achievement and resulting accumulative sales reduction since 2010.

Table 3

Historical Conservation Improvement Program Sales Reductions

Year	Incremental Dth/Yr	% of Sales Achievement	Annual Accumulated Sales Reduction (Dth)
2010	697,322	0.99%	697,322
2011	747,123	1.06%	1,444,445
2012	767,061	1.09%	2,211,506
2013	787,918	1.13%	2,999,424
2014	849,698	1.22%	3,849,121
2015	838,919	1.21%	4,688,040
2016	908,472	1.31%	5,596,512
2017	799,597	1.11%	6,396,110
2018	913,240	1.27%	7,309,350
2019	584,761	0.81%	7,894,111
2020	868,599	1.21%	8,762,711
2010-2020 Cumulative	8,762,711	11.30%	51,848,651

This table shows that the accumulated sales reduction since the last rate case totals over 50 million Dth. To determine the impact on current sales, the Total Adjusted Annual Sales from the Company's current CIP Triennial Plan of 77,527,254 Dth is used.[4] This lost sales total represents about 8 months of total sales.[5] This also shows that the sales reduction in 2021 from these achievements is over 11 percent.[6] This represents a significant disincentive to the utility that decoupling would address.

The Company is now proposing higher savings goals in its recent CIP Plan. Table 4 compares the Company's proposed gas savings goals with the 2021-2023 CIP Triennial Plan.[7]

Table 4

Conservation Improvement Program Goals

Year	Proposed Energy Savings (Dth/Yr)	Total Adjusted Sales	% of Sales Goal
2021	1,059,783	77,527,254	1.37%
2022	1,127,024	77,527,254	1.45%
2023	1,129,427	77,527,254	1.46%

[4] Total Adjusted Sales calculated as the previous three-year weather normalized sales, adjusted for CIP exempt customers as of June 30, 2020. 2021-2023 Minnesota Electric and Natural Gas Conservation Improvement Program, Docket No. E,G002/CIP-20-473.
[5] 51,848,651 Dth in Accumulated Sales Reduction divided by Total Adjusted Annual Sales of 77,527,254 Dth equals 66.9 percent, or more than eight months of annual sales.
[6] 8,762,711 Dth in 2021 Sales Reduction divided by Total Adjusted Annual Sales of 77,527,254 Dth equals 11.3 percent.
[7] 2021-2023 Minnesota Electric and Natural Gas Conservation Improvement Program, Docket No. E,G002/CIP-20-473.

These goals represent a significant increase over historical achievement, both in terms of Dth/Yr and in percent of Sales, driving the need for decoupling to account for the lost sales impacts from these higher savings goals. Decoupling that accounts for the cumulative impact of lost sales may also lessen the need for frequent future rate cases.

Q. IS THE IMPORTANCE OF DECOUPLING FOR THE ACHIEVEMENT OF ENERGY EFFICIENCY GENERALLY RECOGNIZED?

A. Yes. In addition to the statutory recognition of decoupling as a tool to support energy efficiency, the Commission has already approved decoupling mechanisms for three other Minnesota gas utilities. The American Council for an Energy Efficient Economy (ACEEE) reports that 26 states have implemented decoupling mechanisms for gas utilities.[8] ACEEE has repeatedly and consistently emphasized the importance of decoupling as a tool to address the disincentive that energy efficiency represents for utilities, noting for example that "Energy efficiency *does* reduce utility sales, and utilities *should* be able to recover their authorized fixed costs. Decoupling is the simplest way to ensure that a utility meets its revenue requirement even if other factors dampen sales."[9]

Q. PLEASE EXPLAIN THE COMPANY'S REVENUE DECOUPLING MECHANISM (RDM) PROPOSAL.

A. The Company is proposing a full decoupling RDM which includes the effects of weather in the calculation of deferrals. The RDM measures sales revenues

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[8] https://www.aceee.org/blog-post/2020/08/shift-toward-electrification-decoupling-remains-key-driving-decarbonization, accessed 10/13/2021

[9] Gilleo, Kushler, Molina, York: "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms" ACEEE, 2015, https://www.aceee.org/sites/default/files/publications/researchreports/u1503.pdf (emphasis in original).

against a baseline revenue-per-customer by class, with over- or under-recoveries calculated and deferred each month. The annual result is credited or charged to customers through a dollar per therm factor applied to each individual customer's usage each month for twelve months as a separate line item on their bill.

Q. HOW DID THE COMPANY EVALUATE WHICH CLASSES TO INCLUDE IN THE RDM?

A. The Company reviewed all classes for amount of fixed revenue collected volumetrically, and customer class size. Both the Residential and Commercial firm classes collect a significant amount of fixed costs through volumetric rates. When identifying which classes to include in the RDM, the Company also evaluated which classes have fewer than 50 customers. If a customer class has few customers, and one customer makes up a material portion of the class, the other customers would be at risk of significant surcharges if that customer with material usage left the class. Therefore, classes with fewer than 50 customers were omitted from the RDM.

The Company also omitted classes that were on flexible rates. Minn. Stat. § 216B.163, Subd 4, Part 1 states that flexible rates must at least recover the incremental cost to provide service. An RDM adjustment could cause a flexible rate to fall below incremental cost. Also, flexible rate customers have the capability to switch to alternate fuel supplies. Potential bill increases due to a decoupling surcharge could incent these customers to leave the system, leaving fewer sales over which to spread fixed costs. Therefore, we have excluded these customer classes from the RDM.

Q. WHAT CLASSES IS THE COMPANY PROPOSING TO DECOUPLE?

A. The Company is proposing a full decoupling mechanism for its Residential, Small Commercial, and Large Commercial classes. These classes pay 61 percent of their base revenue in volumetric charges. Our decoupling proposal covers approximately 89 percent of the Company's base revenues recovered on a volumetric basis.

Q. WHY DID YOU OMIT THE DEMAND, INTERRUPTIBLE, AND TRANSPORT CLASSES FROM THE RDM?

A. The Demand classes were omitted because the majority of their fixed costs are recovered through fixed demand and customer charges. These classes pay 30 percent of their base revenue in volumetric charges. Also, the Small Demand class has fewer than 50 customers.

The Interruptible classes were omitted because these customers have the option of migrating to flexible rates or firm service. As pointed out in the direct testimony of Ms. Jannell Marks, the larger usage Interruptible customers have migrated over the past few years to the firm Commercial class. Also, as mentioned above, the Large Interruptible class has less than 50 customers. Therefore, we have omitted the Interruptible classes from the RDM.

The Transport classes were omitted from the RDM for several reasons. First, all of these classes have fewer than 50 customers. Second, the Firm Transport class, like the Demand classes, has fixed demand charges that recover a large share of their fixed costs. The Negotiated Transport class was omitted because these customers have the ability to bypass our distribution system, and a decoupling surcharge could incent these customers to leave the system altogether, leaving fewer sales over which to spread fixed costs. Therefore, we have removed the Transport and Negotiated classes from the RDM.

Finally, Generation customers are part of the Demand, Interruptible, and Transport classes and are therefore excluded from the RDM for the reasons described above.

Q. IS THE COMPANY PROPOSING ANY CAPS ON THE DECOUPLING SURCHARGE?

A. Yes. The Company is proposing to implement a maximum single-year class surcharge of ten percent of the base revenue authorized for the class. This cap level on decoupling surcharges has previously been approved by the Commission for CenterPoint Energy (CenterPoint),[10] Minnesota Energy Resources Corporation (MERC),[11] and Great Plains Natural Gas.[12]

Q. UNDER THE PROPOSED RDM, CAN INDIVIDUAL CUSTOMERS BENEFIT FROM CONSERVATION ?

A. Yes. If a customer reduces their usage in the near term, they will see immediate bill reductions for all volumetric charges including natural gas charges. Decoupling measures changes in revenues for the distribution component of the bill, and a decoupling surcharge would impact the distribution charge portion of the bill only. However, a customer who conserves would see savings on distribution charges, rider charges, and the largest component of their bill, natural gas charges. These savings would likely exceed a decoupling surcharge

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[10] *See* Minnesota Public Utilities Commission's June 9, 2014 FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Docket No. G008/GR-13-316).

[11] *See* Minnesota Public Utilities Commission's July 13, 2012 FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Docket No. G007,011/GR-10-977)

[13]*See* Minnesota Public Utilities Commission's September 26, 2016 FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Docket No. G004/GR-15-879)

since it only impacts the distribution charge of the bill. An average residential customer who reduces their usage by five percent would likely see a bill reduction even while paying a decoupling surcharge at the proposed 10 percent surcharge cap.

V. DECOUPLING CRITERIA

Q. IS THE COMPANY'S DECOUPLING PROPOSAL CONSISTENT WITH THE REVENUE DECOUPLING CRITERIA AND STANDARDS THAT THE COMMISSION ESTABLISHED FOR PILOT PROGRAMS[13]?

A. Yes. I will address each of the eight criteria contained in the standards.

1. Criterion 1

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

A. The goal of the RDM is to remove the Company's potential disincentive to promote conservation and energy efficiency for its Residential and Commercial customers. I discussed the relevance of RDM to the Company's pursuit of its conservation goals in detail above.

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.

[13] See Minnesota Public Utilities Commission's June 19, 2009 ORDER ESTABLISHING CRITERIA AND STANDARDS TO BE UTILIZED IN PILOT PROPOSALS FOR REVENUE DECOUPLING (Docket No. E,G999/CI-08-132)

A. The Company proposes to implement a revenue-per-customer decoupling mechanism that includes the effect of weather in the decoupling deferrals. The proposed tariff and Company's RDM model are attached as Exhibit___(CJB-1), Schedule 5 and Exhibit___(CJB-1), Schedule 6, respectively. In her direct testimony, Ms. Terwilliger provides the class-by-class shares of the overall test year revenue requirement. As explained by Ms. Terwilliger, 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 distribution charge for the Residential and Small and Large Commercial firm classes. The revenue requirement recovered through the non-fuel distribution 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 actual revenue collected under the volumetric rates from those customers.

As mentioned above, the RDM will apply to the Residential, Small Commercial, and Large Commercial classes. Annually, the cumulative deferral for each customer group will be incorporated into customer rates for the following year by dividing the deferral amount by the forecast of sales for 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 will be included in the RDM deferrals.

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

A. Yes. The design matches the RDM used by CenterPoint, MERC, and Great Plains Natural Gas. The RDM also matches the RDM that the Company had in place for our electric utility from 2016 through 2019.

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

A. The proposed tariff provides the following deferral calculation:

Monthly RDM Rider Deferral = (FRC * C) – (FDC * Sales), as follows:

Fixed Revenue per Customer * Actual Customer Count

Minus

Fixed Distribution Charge * Actual Sales

The parameters in the RDM are defined and calculated as follows:

<u>Fixed Revenue per Customer (FRC)</u> = Distribution charge revenues (excluding CCRC revenues) divided by customer count, calculated monthly from test year data. Expressed in dollars per customer.

<u>Customer Count (C)</u> = Actual customer count for deferral month.

<u>Fixed Distribution Charge (FDC)</u> = Average distribution charge for each month of test year. Expressed in dollars per therm.

<u>Actual Sales</u> (Sales) = Actual billed sales for deferral month. Expressed in therms.

FRC and FDC are calculated for each month of the test year, using test year revenues, number of customers, and sales. FRC is calculated as the fixed-cost revenue requirement (described below) divided by the customer count forecast for each month in the 2022 test year. FDC is calculated as the fixed-cost revenue requirement (described below) divided by the sales forecast for each month of the 2022 test year.

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

A. It is calculated using the test year distribution charges, less the Conservation Cost Recovery Charge (CCRC) 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 class level. Customer charge revenue is excluded from the RDM because it is already decoupled from sales.

3. Criterion 3

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

A. Company witness Mr. Dylan W. D'Ascendis 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 Residential, Small Commercial, and Large Commercial customer classes.

5. Criterion 5A

Q. HOW WILL DECOUPLING ADJUSTMENTS BE CALCULATED?

A. Separate adjustments will be calculated for the Residential, Small Commercial, and Large Commercial classes. For each group, the monthly deferral amounts will be calculated according to the deferral equation outlined 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 Company witness Ms. Jannell E. 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 with final rates 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?

A. The Company is proposing to implement a maximum single-year class surcharge of ten percent of the base revenue authorized for the class. This cap on surcharges is the same cap amount approved by the Commission for CenterPoint, MERC, and Great Plains Natural Gas. There will be no limit on the rate reduction that the RDM rate adjustment produces.

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 distribution charge in the following year. The deferral could cause the distribution 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 a permanent program.

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 distribution charges, excluding the Conservation Cost Recovery Charge 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.

12. Criterion 6

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

A. No. The Company is already committed to providing a high level of customer service by providing safe, reliable natural gas service, while maintaining customer satisfaction by being responsive to customer needs and investing in technologies to improve the customer experience. This commitment to our customers will not change with the implementation of a decoupling mechanism.

Additionally, the Company is subject to a range of service quality metrics such as telephone response time, customer complaints, and invoicing accuracy. Even in the absence of the existing metrics, the proposed RDM would not introduce a disincentive for the Company to continue providing high-quality customer service. An RDM would only serve as a disincentive if customers were likely to use less gas 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. Company witness Mr. Greg Chamberlain further describes our customer service efforts.

13. Criterion 7

Q. How does the Company propose to evaluate the decoupling mechanism over time?

A. The Company will provide an annual report on April 1 each year based on the items that were required for pilot programs related to the performance of the RDM. The Company proposes to include the proposed streamlined annual revenue decoupling evaluation report items filed by the Minnesota Department of Commerce on July 1, 2020, and approved by the Commission's March 8, 2021 Order.[14]

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. Under Minn. Stat. § 216B.2412, subd 2, the commission shall, by order, establish criteria and standards for decoupling and may establish these criteria and standards in a separate proceeding or in a general rate case or other proceeding in which it approves a pilot program. As prescribed, the decoupling mechanism is being proposed as part of a rate case. In addition, more than one customer class is included in the decoupling proposal.

Q. Please summarize the RDM.

A. The proposed RDM will reduce the disincentive for pursuing increased energy conservation goals and achieving higher levels of gas savings. The RDM will

[14] Please see the Commission's March 8, 2021 Order in Docket No. E002/M-20-180.

also allow the Company to better align the utility's interests with public policy goals, thus making it easier to achieve those goals.

VI. GENERAL RULES AND REGULATIONS

Q. WHAT REVISIONS ARE BEING PROPOSED IN THE COMPANY'S GENERAL RULES AND REGULATIONS TARIFFS?

A. The Company is proposing rate revisions to Section 6, Sheet No. 18.2, Residential Service Extension Policy and Section 6, Sheet No. 19, Winter Construction, of the General Rules and Regulations. These costs have not been revised since the Company's 2004 rate case, Docket No. G002/GR-04-1511.

A. Excess Footage Charges – Section 6, Sheet No. 18.2

Q. WHAT IS AN EXCESS FOOTAGE CHARGE?

A The Excess Footage Charge is the charge customers must pay for service pipeline footage in excess of 75 feet or service footage that the customer requests.

Q. WHAT REVISIONS ARE PROPOSED IN THE EXCESS FOOTAGE CHARGES?

A. Based on current material, labor, and equipment costs, we are proposing an increase in the Excess Footage Charges in Tariff Sheet No. 6-18.2 of the General Rules and Regulations, as shown in Table 5 below.

Table 5

Residential Excess Footage Charges (per foot)

Type	Present Rate	Proposed Rate
Excess Footage	$3.50	$9.10

The cost analysis supporting the increase in this charge is based on increased material, labor, and equipment costs and is provided on page 2 of Exhibit___(CJB-1), Schedule 7.

B. Winter Construction Charges – Section 6, Sheet No. 19

Q. WHAT ARE WINTER CONSTRUCTION CHARGES?

A. When a service or main is installed between October 1 and April 15, customers are subject to a Winter Construction Charge if frost is at least six feet deep, snow removal or plowing is required to install service, or frost burners must be set at the main or underground facilities to install service for the entire length of service or gas main installed.

Q. WHEN INSTALLING A JOINT TRENCH FOR GAS AND ELECTRIC FACILITIES, DOES THE COMPANY CHARGE A CUSTOMER WINTER CONSTRUCTION CHARGES FOR BOTH ELECTRIC AND GAS?

A. No. If the Company's gas and electric facilities are installed in a joint trench for any portion, the Company will waive the lower of the gas and electric Winter Construction Charges on the joint portion.

Q. WHAT REVISIONS ARE PROPOSED IN THE WINTER CONSTRUCTION CHARGES?

A. There are two components to the Winter Construction Charges, as indicated on Tariff Sheet No. 6-19 of the General Rules and Regulations. The Company is proposing an increase in each as shown in Table 6 below.

Table 6

Winter Construction Charges

Type	Present Rate	Proposed Rate
Excavation (Per Excavation Unit)	$400	$685
Main & Service Extensions (Per Trench Foot)	$3.00	$8.90

The cost analysis supporting these proposed rate charges is based on current material, labor, and equipment costs, and is provided on page 3 of Exhibit___(CJB-1), Schedule 7. These costs were last set in our tariff in 2004 and the proposed increase generally reflects inflationary pressure to these costs over more than a decade.

C. Other Revenue Impact

Q. HAVE YOU INCLUDED AN INCREASE TO OTHER REVENUES TO RECOGNIZE THESE PROPOSED RATE INCREASES?

A. Yes. Other revenues have increased $690,756 as shown on page 1 of Exhibit___(CJB-1), Schedule 7. It is also shown on Schedule 5 to Ms. Terwilliger's testimony. The proposed increase in these charges reduces the increase in retail revenues proposed by Ms. Terwilliger.

VII. CONCLUSION

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. The Company has prepared a fully-embedded CCOSS as part of these proceedings, including background explanation on CCOSS concepts, as well as detailed documentation of the current CCOSS. This CCOSS meets all the objectives for proper CCOSS preparation, including identification of the revenues, costs and profitability for each class of services, as required by Minn. R. 7825.4300, subp. C. Other than some minor allocator updates, this version of the CCOSS adheres to the same methods employed by the Company in its previous rate cases. The results of this CCOSS have then been used by Ms. Terwilliger as the basis for rate design.

The Company has also proposed a full decoupling mechanism for its Residential, Small Commercial, and Large Commercial customer classes.

Finally, the Company has also proposed reasonable changes to its Excess Footage and Winter construction charges.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications and Experience
Christopher J. Barthol

OVERVIEW

My responsibilities at Xcel Energy include Class Cost of Service Studies conducted in support of the Company's rate cases and providing pricing function support and other related analyses for the utility operating subsidiaries of Xcel Energy.

PROFESSIONAL EXPERIENCE

Principal Pricing Analyst; Xcel Energy, NSPM	2017 – Present
Senior Regulatory Analyst; Xcel Energy, Xcel Energy Services	2015 – 2017
Pricing and Cost-of-Service Analyst; PacifiCorp	2013 – 2015
Associate Pricing and Cost-of-Service Analyst; PacifiCorp	2011 – 2013

EDUCATIONAL BACKGROUND

Purdue University; MS Agricultural Economics	2010
Saint Cloud State University; BA Economics	2008

Guide to the Gas Class Cost of Service Study (CCOSS)
Northern States Power Company

I. Overview

The purpose of the Northern States Power Company (NSP) gas Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as residential, commercial, demand, interruptible, and transport. For example, distribution mains costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as production, storage, transmission, and distribution. The CCOSS also assigns ***direct*** costs (e.g. purchased gas expenses), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. Dth commodity usage and design day requirements), which are the drivers of the costs.

The two basic types of costs are: (1) capital costs associated with investment in production, storage, transmission and distribution facilities and (2) on-going expenses such as purchased gas, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class's share of the capacity, commodity, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A CCOSS begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three basic steps:

1. <u>Functionalization</u> – The identification of each cost element as one of the six basic utility service "functions." The four main categories are production, storage, transmission, and distribution. There are also two other categories for general and common plant/expenses.
2. <u>Classification</u> – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. Dths of demand, Dths of commodity usage or number of customers).
3. <u>Allocation</u> – The allocation of the functionalized and classified costs to customer classes, based on each class's respective service requirements (e.g. Dths of demand, Dths of commodity usage, and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the gas utility system. Costs must first be functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four main functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function	Description
Production	304, 305, 311, 108(1), 190, 281-283 Net, 710, 733, 735, 736, 742, 759, 840-843, 403, 408.1, 410.1, 411.1, 420	None	Includes capital and associated operations and maintenance expenses related to manufacturing, buying, or producing gas. These costs include pipeline or producer gas purchases and producing owned or peaking gas.
Storage	360-363, 108(5), 190, 281-283 Net, 403, 408, 410.1, 411.1, 420	None	Includes capital and associated operations and maintenance expenses related to storing off-peak gas for use during the winter-peaking months.
Transmission	365-371, 108(7), 190, 281-283 Net, 107, 850-865, 403, 408.1, 410.1, 411.1, 420	None	Includes costs associated with transporting gas from interstate pipelines to the Company's distribution system. These included capital costs associated with transmission mains as well as operations and maintenance expenses associated with town border stations.
Distribution	374-376, 378-381, 383, 108(8), 281-283 Net, 107, 871, 874, 875, 877-881, 885, 887, 889, 891, 892, 403, 408, 410.1, 411.1, 420	"Customer" portion of the Distribution Mains	Includes the customer-related capital and operating costs associated with delivering gas to customers (distribution mains and services, customer services, meters, regulators)
		"Demand" portion of Distribution Mains	Includes the demand-related capital and operating costs associated with delivering gas to customers (distribution mains and services, customer services, meters, regulators)

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three principle service requirements or billing components are:

1. Demand – Costs that are driven by customers' maximum dekatherm ("Dth") demand.
2. Commodity – Costs that are driven by customers' energy or dekatherm ("Dth") requirements.

3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs were classified:

Function/Sub-Function	**Cost Classification**		
	Demand	**Customer**	**Commodity**
Production	X		X
Storage	X		
Transmission	X		
Distribution (Customer-Related)		X	
Distribution (Demand-Related)	X		

As shown in the table above, distribution costs are classified as both "demand" and "customer" related. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The Company utilizes a minimum system methodology for determining the portion of costs that are demand- and customer related.

V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of two ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. An example of a directly assigned cost is purchased gas expenses or transmission mains.
- Allocation - Most gas utility costs are incurred common or jointly in providing service to all or most customers and classes. Therefore, allocation methods must be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
    - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100 percent.
    - There are two types of allocators:
        - External Allocators –These are allocators that are based on data from outside the CCOSS model (e.g. design day demands, metering and customer service-related cost ratios). In general, there are three types of external allocators:
            - Capacity –related (sometimes referred to as Demand) allocators such as:
                - Design Day Demands – each firm class's usage in extreme peaking conditions
                - Excess Design Day – the portion of design day demand in excess of average daily sales
            - Commodity-related allocators such as:
                - Sales W/Transp – Forecasted sales, including forecasted transportation

        - Sales W/o Transp – Forecasted sales without forecasted transportation
    - ❑ Customer-related allocators
        - Number of customers
        - Weighted number of customers, where the weights are based on cost of meters, services, billing, etc.

    Details on the external allocators used in the CCOSS model are shown in Volume 3, Required Information, Page 10.

- Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as Dths demand, Dths of energy or the number of customers. Examples of internal allocators include:
    - ❑ Average and Peak – portion of mains costs that are not allocated on customers
    - ❑ Mains, Overall – total effect of mains allocated on customers, sales with transport, and excess design day
    - ❑ Prod-Stor-Trans-Distr – Total production, storage, transmission, and distribution from original plant investment

    Details on the development of the internal allocators used in the CCOSS model are shown in Exhibit___(CJB-1), Schedule 3, Page 9.

VI. Classification and Allocation of Production, Storage, Transmission, and Distribution Plant and Expenses

A. Production and Storage Plant

Production costs include production-related land and land rights, structures and improvements, liquefied petroleum, and other expenses. Storage costs also include storage-related land and land rights, structures and improvements, gas holders, and purification equipment. These costs are classified as demand-related and allocated with a Design Day allocator. Production-related expenses such as the Minnesota Manufactured Gas Plant (MGP) are classified as energy-related and allocated with a Sales Without Transport allocator.

B. Transmission Plant

Transmission costs include transmission pipe-related land and land rights, rights-of-way used in connection with transmission operations, structures and improvements, and transmission mains. Transmission main costs that can be segregated to a specific class are directly assigned to that class. Those costs that are not directly assigned are classified as demand-related and allocated with an average and peak allocator.

C. Distribution Plant

Distribution Plant includes the pipelines, meters, and other infrastructure needed to deliver natural gas from the transmission system to customers' premises. The categories of Distribution Plant are: 1) distribution mains, 2) services (i.e., the pipe going to homes and businesses), 3) meters and regulators, and 4) regulator stations. The Table below shows the amount of distribution plant by category and how they are classified:

Distribution Plant Category	2022 TY Plant in Service (000)	Demand Component	Customer Component
Distribution Mains	$850,726	X	X
Services	$355,443		X
Meters & Regulators	$157,661		X
Regulator Stations	$605	X	

VII. Distribution Plant Cost Studies within CCOSS

There are three distribution cost studies within the CCOSS:
- Minimum System Study
- Meter and Regulator Study
- Service Study

Minimum System Study
The National Association of Regulatory Utilities Commissioners (NARUC) Gas Distribution Rate Design manual states that a portion of distribution mains may be classified as customer-related (with the remainder of costs classified as demand related) and that Minimum System studies may be utilized to derive the customer- and demand-related components of distribution mains. Consistent with this guidance, I utilized a Minimum System Study to establish the classification percentages of distribution mains.

The Minimum System method involves comparing the cost of the minimum size of distribution mains used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost. The table below shows the classification of distribution main costs.

Cost	Customer	Demand
Distribution Costs	**63.5%**	**36.5%**

The total cost of mains is split among Minimum System, Average Capacity, and Excess Capacity components. The Minimum System component identifies the cost to establish basic connectivity between the utility and the customer, using pipes with a diameter of two inches or less, which is the minimum-sized pipe for mains on our system. If all the mains in the Company's entire distribution system in Minnesota consisted of two-inch pipe, the initial plant investment would have been 63.5 percent of actual investment. These Minimum System costs are allocated to class based on the number of customers in each class and are also assigned to the Customer Charge billing component.

Average Capacity costs are determined by taking the remaining 36.5 percent of the total cost of mains and multiplying by the test year 2022 system load factor. The system load factor is calculated by taking the Company's forecasted total sales (2022 Test Year Sales forecast of 111,111,955 Dth) and dividing that by the Company's peak demand (2021-2022 Design Day Demand of 881,141 Dth) and multiplying that by 365 days in the year. The test year 2022 forecasted system load factor is 34.5 percent. Multiplying the 36.5 percent of the remaining total cost of mains by the system load factor leads to an Average Capacity of 12.6 percent. These Average Capacity costs are allocated to class based on sales (including transportation sales). Then the results are credited to the Demand billing component and Base sub-component. The Base sub-component is comprised of non-seasonal and non-peak demand.

The Excess Capacity component is the remaining 23.9 percent of total cost of mains not ascribed to the Minimum System and Average Capacity components. The Excess Capacity costs are allocated to class using an Excess Design Day allocator. The Excess Design Day allocator is calculated by taking the difference between each class's Design Day demand and Average Daily Sales. Then, each class amount is credited to the Demand cost component and Seasonal sub-component.

Meter and Regulatory Study

A Meter and Regulator Study assigns meter costs and costs for pressure-regulating equipment to each class. Information is gathered on meter and regulator equipment and installation costs, the premises identification numbers associated with different meters, and the premises identification numbers associated with each rate code/class. From this list, total meter costs are developed for each class and divided by the number of meters in each class to develop a cost per meter weighting. Since the residential class had the lowest cost per meter and regulator, they received a customer weighting of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 1.51, Large Commercial – 5.62, Small Demand – 14.38, Large Demand – 25.78, Small Interruptible – 17.04, Medium Interruptible – 38.26, Large Interruptible – 20.69, Firm Transport – 25.78, Interruptible Transport – 38.26, Negotiated Transport – 20.69, System Generation – 34.10, and Transport Generation – 24.51. The meter cost weighting for each class is applied to the number of customers in each respective class in order to calculate the Meters and Regulators Study allocator.

Service Study

A Services Study assigns gas services costs to each class. Services costs are the costs of service pipelines used to connect distribution mains to customers' premises. Information is gathered on premise identification numbers, service pipe type, service pipe length, and class associated with each premise. The cost per foot of each service pipe type is applied to each class based on the service pipe types and footage used in each class. This calculation allows us to determine the total cost of service pipes for each class. The total cost by class is divided by the number of customers in each class. Since the cost per customer for the residential class was lowest, that class received a weight of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 1.84, Large Commercial – 2.75, Small Demand – 11.10, Large Demand – 5.63, Small Interruptible – 7.07, Medium Interruptible – 7.48, Large Interruptible – 6.59, Firm Transport – 5.63, Interruptible Transport – 7.48, Negotiated Transport – 6.59, System

Generation – 6.86, and Transport Generation – 6.11. The service weightings are applied to the number of customers in each class. The weighted customers are then utilized to derive the Service Study allocator.

VIII. Other Cost Studies within CCOSS

Customer Care Studies

Two Customer Care studies were conducted within the CCOSS: 1) a Customer Records and Collections Study and 2) a Customer Information Study. The Customer Records and Collections Study, and the Customer Information Study were developed to allocate costs associated with Federal Energy Regulatory Commission (FERC) Accounts 903 and 908, respectively. FERC Account 903 costs include materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints. FERC Account 908 costs include materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to promote safe, efficient, and economical use of the utility's service.

The Customer Records and Collections Study first determines the costs associated with billing and call centers for each class on a cost per customer basis. To make this determination, I first directly assign those FERC Account 903 costs that can be directly assigned to a specific class. Those FERC Account 903 costs that cannot be directly assigned are allocated based on the number of customers in each class. Since the cost per customer for the residential class is lowest, that class receives a weighting of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 0.95, Large Commercial – 0.84, Small Demand – 60.00, Large Demand – 60.00, Small Interruptible – 60.00, Medium Interruptible – 60.00, Large Interruptible – 60.00, Firm Transport – 60.00, Interruptible Transport – 60.00, Negotiated Transport – 60.00, System Generation – 60.00, and Transport Generation – 60.00. The weightings are derived for all other classes by dividing their cost per customer by that of the residential class. The weightings are then applied to the number of customers in each class. The weighted customers are used to derive the allocator for customer records and collections expenses.

In the same manner as the Customer Records and Collections Study, the Customer Information Study determines the costs associated with customer account management, expenses associated with low-income customers, and business development by directly assigning the FERC Account 908 costs that can be directly assigned to a specific class. Costs that cannot be directly assigned to a class are allocated based on the number of customers in each class.

Since the cost per customer for the residential class is lowest, that class receives a weighting of 1.0. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 0.93, Large Commercial – 10.00, Small Demand – 60.00, Large Demand – 60.00, Small Interruptible – 60.00, Medium Interruptible – 60.00, Large Interruptible – 30.00, Firm Transport – 60.00, Interruptible Transport – 60.00, Negotiated Transport – 30.00, System Generation – 60.00, and Transport Generation – 60.00. The weightings are derived for all other classes by dividing their cost per customer by that of the residential class. The weightings are then applied to the number of customers in each class. The weighted customers are used to derive the allocator for costs associated with customer account management, expenses associated with low-income customers, and business development.

Uncollectibles Study
The Uncollectibles Study consists of gathering information on customer debtor numbers, net uncollectibles (bad debt less recoveries) for each debtor number, and classes associated with each debtor number to determine the net uncollectibles for each class. The net uncollectibles are then calculated for each class and used to derive the allocation of uncollectibles.

Late Fee Study
The Late Payment Study follows the same process as the Uncollectibles Study as it determines customer late fees by class. The late fees by class are used to derive the late fee revenue allocator and assign late payment revenues to each customer class.

IX. Direct Assignment of Transmission Plant and Related Expenses

Plant and related expenses associated with transmission mains that only serve two of our Transport Generation customers were isolated and directly assigned to that class. Production, storage, and distribution plant and related expenses related to these two customers were not allocated to the Transport Generation class by removing their respective sales from the Modified Sales W/Transport allocator, customer counts from the Modified Customer Counts allocator, and Design Day demands from the Design Day and Excess Design Day allocators. For transmission plant and related expenses, the remaining costs that are not directly assigned are allocated to the classes via the average and peak allocator.

X. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Small Commercial
3. Large Commercial
4. Small Demand
5. Large Demand
6. Small Interruptible
7. Medium Interruptible
8. Large Interruptible
9. Firm Transport
10. Interruptible Transport
11. Negotiated Transport
12. System Generation
13. Transport Generation

XI. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "Tot") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab is shown in parenthesis below):

1. Billing Unit:
    a. Demand (Dem)
    b. Customer (Cus)
    c. Commodity (Com)

2. Function and Associated Sub-Function
    a. Demand (Dem)
        a) Base (Base)
        b) Seasonal (Seas)
        c) Peak Shaving (Peak)

In the CCOSS spreadsheet there is a separate worksheet tab for each of the above billing units, functions and sub-functions. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

XII. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accumulated Depreciation Reserve – Accumulated Deferred Income Tax + Additions to Net Plant

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "cost" responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "cost" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function, and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function, and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (less off-setting credits from Other Operating Revenues)

+

(((% Return on Invest x Rate Base) - AFUDC - Fed Credits) x 1 / (1 - Fed T) - Fed Section 199 Deduc x Fed T/(1-Fed T) - State Credits) x 1 / (1 - State T)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)

Where:

Tax Rate = 1 – (1- State T) x (1-Fed T)

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax
+ Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit
+ Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class's "revenue" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes – Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "revenue" responsibility differs from class **"cost"** responsibility.

XIII. Allocator Descriptions

In the table below, the Name column briefly describes what the allocator is, and the Derivation column describes how the allocator was created. The E/I column tells whether an allocator is external or internal. (An external allocator is one that was prepared outside of the CCOSS. An internal allocator is created within the CCOSS by combining the results of external allocators and / or other internal allocators.) The Components column indicates to which billing component(s) the allocator applies, including possibly the two demand subcomponents. (C=Customer, D=Demand, E=Energy, B=Base Demand, S=Seasonal Demand and P=Peak Shaving Demand). Most lines of this table show normal allocators that first spread dollars to class and then spread each class amount to billing and subcomponents. But some allocators, such as Present Retail Revenue, only spread dollars to class. And a few other allocators, such as Mod Present Revenue, only spread dollars to billing component. (These latter allocators are only used after dollars have already been spread to class-by-class allocators.) Such two-stage allocations are indicated in the Alloc column of the CCOSS with a semi-colon (e.g., "Pres Rev; Mod Pres Rev").

Name	Derivation	E/I	Components
1/2 Dsgn Day, 1/2 Ener	Average class percents from the Design Day and Sales, W/ Transp allocators	Int	DE- P
1/2 Mod Rt Bs, 1/2 Mod Pres Rv (Component only)	Average class percents from Mod Pres Rev and Mod Rate Base column allocators	Int	CDE-BSP
1/2 Rt Base, 1/2 Pres Rev; (Class only)	Average class percents from the Rate Base and Present Retail Revenue allocators	Int	---
Average and Peak	Total effect of mains allocated on excess design day and average sales	Int	D -BS
Cust Inform Study	Forecasted customers, weighted by the typical cost to serve each class	Ext	C -
Customers	Forecasted customers	Ext	C -
CWIP	Construction Work In Process	Int	CD -BSP
Design Day	Each firm class's participation in extreme peak conditions	Ext	D - P
Dist Exp, w/o Sup & Eng	Distribution O&M expenses, excluding Supervision & Engineering	Int	CDE-BSP
Distribution Plant	Total original investment in mains, services, meters and regulators	Int	CD -BS
Excess Design Day	The portion of Design Day in excess of average daily sales	Ext	D - P
Gas Plant In Service	Total original capital investments	Int	CD-BSP
Labor	Total of various labor-related expenses	Int	CDE-BSP
Labor w/o A&G	All labor expenses except A&G	Int	CDE-BSP
Late Pay Penalties (Class only)	Late pay penalties	Ext	---
Mains, Overall	Total effect of mains allocated on customers, sales with transport & excess design day	Int	CD -BS
Meter & Regul Study	Customer count, weighted by relative cost of each class's average meter and regulator	Ext	C -
Mod Present Reven (Component only)	Present Retail Revenue, w/o Gross Earnings, Late Pay, etc.	Int	CDE-BSP
Mod Rate Base (Component only)	Column version of Rate Base excluding Working Cash	Int	CDE-BSP
Modified O&M Expense	Total O&M expense, less rate case expense and various Admin & General expenses	Int	CDE-BSP
Net Plant	Plant In Service, minus Accumulated Depreciation	Int	CD -BSP
Other Production Expense	Miscellaneous production expenses for LPG, LNG, etc.	Int	DE- P
Present Retail Rev (Class only)	Forecasted present revenue	Ext	---
Prod-Stor-Tran-Dis	Total Production, Storage, Transmission and Distribution, from original plant investment	Int	CD -BSP
Rate Base	Rate Base (Plant in Svc, less Accumulated Deprec, plus and minus other adjustments)	Int	CDE-BSP
Record & Coll Study	Forecasted customers, weighted by typical cost to provide billing records and collections	Ext	C -
Rt Base, w/o Work Cash	Rate base, excluding working cash	Int	CDE-BSP
Sales, W/ Transp	Forecasted sales, including forecasted transportation	Ext	E-
Sales, W/o CIP Exempt	Forecasted sales, w/o forecasted CIP-exempt sales	Ext	E-
Sales, W/o Transp	Forecasted sales, w/o forecasted transportation	Ext	E-
Service Study	Customer count, weighted by relative cost of each class's average service	Ext	C -

Name	Derivation	E/I	Components
Tran & Distrib	Transmission and Distribution plant (original investment)	Int	CD -BS
Uncollectibles Study	Forecasted customers, weighted by the typical cost of each class's uncollectibles	Ext	C -

XIV. Allocator Index

The following table lists all the CCOSS allocators, in alphabetical order. If a given allocator is used multiple times within the CCOSS, those occurrences are further sorted by page and line number. Most allocators are used to spread dollars both to class and then billing component. But as indicated parenthetically, some allocators are used only for class allocations or only for billing component allocations.

Allocator	Category	Item	Page	Line
1/2 Dsgn Day, 1/2 Ener	Pres Other Oper Rev	Other - Miscellaneous	5	11
	Other Production Exp	Misc. LNG Op Exp	5	26
	Distribution O&M Exp	Dispatching	5	37
1/2 Rt Base, 1/2 Pres Rev (Class only)	Admin & General	Injuries and Claims	6	15
		General Advertising	6	18
		Misc General Exp	6	19
		Rents	6	20
		Maint of Gen Plt	6	21
Average and Peak	Plant in Service	Transmission Plant	3	3
		Regulator Stations	3	6
	Accum Depr Rsv	Transmission Plant	3	20
		Regulator Stations	3	23
	Accum Defer IT	Transmission Plant	3	35
		Regulator Stations	3	38
	CWIP	Transmission Plant	4	3
		Regulator Stations	4	6
	Transmiss O&M Exp	Transmission Expense	5	28
	Distribution O&M Exp	Regulator Stations	5	31
	Book Deprec	Transmission Plant	6	32
		Regulator Stations	6	35
	Rl Estate & Prop Tax	Transmission Plant	7	3
		Regulator Stations	7	6
	Provis-Defer Inc Tax	Transmission Plant	7	19
		Regulator Stations	7	22

Allocator	Category	Item	Page	Line
Average and Peak	Investment Tax Credit	Transmission Plant	7	35
		Regulator Stations	7	38
	Tax Depr & Removal	Transmission Plant	8	3
		Regulator Stations	8	6
	AFUDC	Transmission Plant	8	36
		Regulator Stations	8	39
Cust Inform Study	Cust Acctg & Inform	Asst Expense (w/o CIP)	6	6
Customers (Also Modified Customers)	Plant in Service	Mains - Minimum System	3	7
	Pres Other Oper Rev	Connection Charges	5	4
		Return Check Charges	5	5
		Connect Smart	5	6
		Distribution Other	5	10
		Incr Misc Serv	5	14
	Distribution O&M Exp	Other Property & Equipment	5	36
		Customer Installations	5	38
		Other Distribution	5	39
	Cust Acctg & Inform	Acct Superv	6	1
		Acct Meter Read	6	2
		Acct Misc	6	5
	Labor Allocator	Customer Accounting	8	48
		Cust Serv & Inform	8	49
CWIP	Income Tax Additions	Avoided Tax Interest	8	19
	AFUDC	Total AFUDC	8	29

Allocator	Category	Item	Page	Line
Design Day	Plant in Service	Production Plant (LPG)	3	1
		Storage Plant (LNG)	3	2
	Accum Depr Rsv	Production Plant (LPG)	3	18
		Storage Plant (LNG)	3	19
	Accum Defer IT	Production Plant (LPG)	3	33
		Storage Plant (LNG)	3	34
	CWIP	Production Plant (LPG)	4	1
		Storage Plant (LNG)	4	2
	Pres Other Oper Rev	Interchange Gas	5	7
		Damage Claim	5	8
		Ltd Firm Sales - Rsrvs & Vols	5	9
	Purchased Gas Exp	Propane	5	20
		Limited Firm	5	21
	Other Production Exp	Other Purchased Gas	5	23
		Misc. LPG Op Exp	5	25
	Book Deprec	Production Plant (LPG)	6	30
		Storage Plant (LNG)	6	31
	Rl Estate & Prop Tax	Production Plant (LPG)	7	1
		Storage Plant (LNG)	7	2
	Provis-Defer Inc Tax	Production Plant (LPG)	7	17
		Storage Plant (LNG)	7	18
	Investment Tax Credit	Production Plant (LPG)	7	33
		Storage Plant (LNG)	7	34
	Tax Depr & Removal	Production Plant (LPG)	8	1
		Storage Plant (LNG)	8	2
	AFUDC	Production Plant (LPG)	8	34
		Storage Plant (LNG)	8	35
	Labor Allocator	Transmission	8	54
	Plant in Service	Transmission	3	4
	Accum Depr Rsv	Transmission	3	21
	Accum Defer IT	Transmission	3	36
	CWIP	Transmission	4	4

Allocator	Category	Item	Page	Line
Design Day	Purchased Gas Exp	Commodity	5	18
		Demand	5	19
	Book Deprec	Transmission	6	33
	Real Estate & Prop Taxes	Transmission	7	4
	Provis-Defer Inc Tax	Transmission	7	20
	Investment Tax Credit	Transmission	7	36
	Tax Depr & Removal	Transmission	8	4
	AFUDC	Transmission	8	37
Direct Assign (Class only)	Pres Retail Revenue	Present Retail Rev	5	1a
	Prop Retail Revenue	Proposed Retail Rev	5	1b
Dist Exp, w/o Sup & Eng	Distribution O&M Exp	Supervision & Engineering	5	40
	Labor Allocator	Distribution	8	50
Excess Design Day	Plant in Service	Mains - Excess Capacity	3	9
Labor	Accum Defer IT	Non-Plant Related	3	47
	Non-Plt Asset-Liab	Non-Plant Assets & Liab	4	15
	Admin & General	Pension & Benefit-Direct	6	9
		Salaries	6	10
		Office & Supplies	6	11
		Admin Transfer Credit	6	12
		Outside Services	6	13
		Incentive Compensation	6	14
	Cust Service & Info	Amortizations	6	24
	Tot Rl Est & Prop Tax	Payroll Taxes	7	15
	Provis-Defer Inc Tax	Non-Plant Related	7	31
	Inc Tax Deductions	Other Timing Differences	8	23
		Meals	8	24
Labor w/o A&G	Labor Allocator	Admin & General	8	51
Late Payment Study	Pres Other Oper Rev	Late Pay Penalties	5	3
	Prop Other Oper Rev	Incr Late Pay - Proposed	5	13

Allocator	Category	Item	Page	Line
Mains, Overall	Accum Depr Rsv	Mains	3	24
	Accum Defer IT		3	39
	CWIP		4	7
	Distribution O&M Exp		5	32
	Book Deprec		6	36
	Rl Estate & Prop Tax		7	7
	Provis-Defer Inc Tax		7	23
	Investment Tax Credit		7	39
	Tax Depr & Removal		8	7
Meter & Regul Study	Plant in Service	Meters	3	12
		House Regulators	3	13
	Accum Depr Rsv	Meters	3	26
		House Regulators	3	27
	Accum Defer IT	Meters	3	41
		House Regulators	3	42
	CWIP	Meters	4	9
		House Regulators	4	10
	Distribution O&M Exp	Meters	5	34
		House Regulators	5	35
	Book Deprec	Meters	6	38
		House Regulators	6	39
	Rl Estate & Prop Tax	Meters	7	9
		House Regulators	7	10
	Provis-Defer Inc Tax	Meters	7	25
		House Regulators	7	26
	Investment Tax Credit	Meters	7	41
		House Regulators	7	42
	Tax Depr & Removal	Meters	8	9
		House Regulators	8	10
	AFUDC	Meters	8	42
		House Regulators	8	43
Modified O&M Expense	Working Cash	Total Working Cash	4	20

Allocator	Category	Item	Page	Line
Net Plant	Accum Defer IT	Accumulated Deferred Tax	3	46
	Admin & General	Property Insurance	6	8
	Provis-Defer Inc Tax	Tax Benefit Transfers	7	30
	Tax Depr & Removal	Tax Benefit Transfers	8	14
Other Production Exp	Labor Allocator	Production	8	52
Present Rev; Mod Pres Rev (Class only)	Admin & General	Regulatory Comm Exp	6	16
		Duplicate Charge Credit	6	17
	Amortizations	Rate Case Exp Amort	6	25
Prod-Stor-Tran-Dis	Plant in Service	General Plant	3	15
		Common Plant	3	16
	Accum Depr Rsv	General Plant	3	29
		Common Plant	3	30
	Accum Defer IT	General Plant	3	44
		Common Plant	3	45
	CWIP	General & Common Plant	4	11
	Book Deprec	General Plant	6	41
		Common Plant	6	42
	Rl Estate & Prop Tax	General Plant	7	12
		Common Plant	7	13
	Provis-Defer Inc Tax	General Plant	7	28
		Common Plant	7	29
	Investment Tax Credit	General Plant	7	44
		Common Plant	7	45
	Tax Depr & Removal	General Plant	8	12
		Common Plant	8	13
	AFUDC	General Plant	8	42
		Common Plant	8	43
Record & Coll Study	Cust Acctg & Inform	Acct Recrds & Coll	6	3
Sales, W/ Transp & Modified Sales W/Transp	Plant in Service	Mains - Average Capacity	3	8
	Gas In Storage	Total Gas in Storage	4	14
	Sales Expense	Sales, Econ Dvlp & Other	6	27
	Labor Allocator	Sales	8	53

Allocator	Category	Item	Page	Line
Sales, W/o CIP Exempt	Amortizations	CIP / DSM Amortization	6	23
Sales, W/o Transp	Miscellaneous	Fuel	4	18
	Other Prod Expense	MGP	5	24
Service Study	Plant in Service	Services	3	11
	Accum Depr Rsv		3	25
	Accum Defer IT		3	40
	CWIP		4	9
	Distribution O&M Exp		5	33
	Book Deprec		6	37
	Rl Estate & Prop Tax		7	8
	Provis-Defer Inc Tax		7	24
	Investment Tax Credit		7	40
	Tax Depr & Removal		8	8
	AFUDC		8	41
Tran & Distrib	Material & Supply	Materials & Supplies	4	13
	Miscellaneous	Prepay: Insurance	4	16
		Prepay: Miscellaneous	4	17
Uncollectibles Study	Cust Acctg & Inform	Acct Uncollect	6	4

XV. Class Cost of Service Table of Contents

Page 1 contains a summary of the allocated rate base and income statement.

Page 2 contains the revenue deficiency/excess by class assuming each class has an equal return on rate base. It also shows the classification components (e,g., customer related, capacity related). This can be used to design cost-based intra-class rates for customers. For example, the CCOSS shows the total revenue deficiency for the residential customer class as $39,953,641 and the cost-based customer charge for residential of $24.14 per month. The cost classifications (e.g.

customer related) are only shown as a total class revenue deficiency. However, the Company does have the same data as below for each cost classification category.

Pages 3 through 8 contain in more detail the components of the rate base and income statement along with the method used to allocate the various cost components. Each item contains a line number along with a description of the item. For those items that use an allocator to split the costs between classes, the next column ("Alloc") shows the name of the allocation method. A value that is not allocated but directly assigned to each class will contain the designation "Direct." Calculated lines such as subtotals do not have a designation in this column. The remaining columns contain the Minnesota jurisdictional total and the class cost allocations for each item.

Pages 9 and 10 contain external allocators and certain internal allocation percentages.

Page 11 contains certain cost of capital items and tax rates used in the CCOSS.

Class Cost of Service Study ($000); Test Year 2022 | Page 1 of 1

Equal Return vs Present

	Operating Revenue Requirement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Return On Rate Base	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%
2	Equalized Total Retail Rev	576,645	356,746	148,947	16,101	36,712	4,681	13,457
3	Present Total Retail Revenue	541,016	316,793	153,749	17,962	40,149	5,248	7,115
4	Revenue Deficiency	35,629	39,954	-4,802	-1,861	-3,437	-567	6,342
5	Deficiency / Pres Total Retail Rev	6.59%	12.61%	-3.12%	-10.36%	-8.56%	-10.80%	89.13%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	144,483	128,697	14,816	329	575	53	13
7	Average Monthly Customers	480,825	444,262	36,092	140	298	26	7
8	Revenue Requirement $ / Mo / Cust	25.04	24.14	34.21	196.08	160.57	171.01	150.80
9	Capacity Retail Revenue Requirement	86,922	41,637	24,827	2,619	2,199	3,193	12,447
10	Annual Dkt Sales	111,111,955	38,929,911	23,001,688	2,990,585	9,468,854	13,381,819	23,339,097
11	Revenue Requirement $ / Dkt	0.78	1.07	1.08	0.88	0.23	0.24	0.53
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	23,658	8,641	5,159	676	2,199	2,985	3,998
13	Capacity - Seasonal Revenue Requirement	44,640	23,254	13,851	1,336	0	132	6,067
14	Peak Shaving Revenue Requirement	18,624	9,741	5,818	606	0	76	2,382
15	Base Rev Requirement $ / Dkt	0.21	0.22	0.22	0.23	0.23	0.22	0.17
16	Seasonal Rev Requirement $ / Dkt	0.40	0.60	0.60	0.45	0.00	0.01	0.26
17	Peak Shave Rev Requirement $ / Dkt	0.17	0.25	0.25	0.20	0.00	0.01	0.10
18	Energy Retail Revenue Requirement	24,428	11,519	6,876	885	2,798	1,435	917
19	Revenue Requirement $ / Dkt	0.22	0.30	0.30	0.30	0.30	0.11	0.04
20	Total Internal Retail Revenue Requirement	255,833	181,852	46,519	3,833	5,572	4,681	13,376
21	Revenue Requirement $ / Dkt	2.30	4.67	2.02	1.28	0.59	0.35	0.57
22	Revenue Requirement $ / Mo / Cust	44.34	34.11	107.41	2,281.42	1,557.17	15,003.68	159,238.14
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	66,581	40,418	23,692	2,464	0	0	9
24	Energy Revenue Requirement	253,474	133,777	78,680	9,804	31,140	0	73
25	Total External Revenue Requirement	320,055	174,195	102,371	12,268	31,140	0	81
26	Cap Revenue Requirement $ / Dkt	0.60	1.04	1.03	0.82	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.28	3.44	3.42	3.28	3.29	0.00	0.00
28	Tot Revenue Requirement $ / Dkt	2.88	4.47	4.45	4.10	3.29	0.00	0.00
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	144,483	128,697	14,816	329	575	53	13
30	Capacity Revenue Requirement	153,503	82,054	48,519	5,082	2,199	3,193	12,455
31	Energy Revenue Requirement	277,902	145,296	85,556	10,689	33,938	1,435	989
32	Total Revenue Requirement	575,888	356,047	148,890	16,101	36,712	4,681	13,457
33	Customer Revenue Reqt $ / Dkt	1.30	3.31	0.64	0.11	0.06	0.00	0.00
34	Demand Revenue Reqt $ / Dkt	1.38	2.11	2.11	1.70	0.23	0.24	0.53
35	Energy Revenue Reqt $ / Dkt	2.50	3.73	3.72	3.57	3.58	0.11	0.04
36	Total Revenue Reqt $ / Dkt	5.18	9.15	6.47	5.38	3.88	0.35	0.58

Proposed Return vs Present

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
37	Proposed Total Retail Revenue	576,645	344,793	159,419	18,249	40,734	6,233	7,216
38	Revenue Deficiency	35,629	28,000	5,671	288	584	985	101
39	Deficiency / Pres Total Oper Revenue	6.59%	8.84%	3.69%	1.60%	1.46%	18.77%	1.42%

Proposed Return vs Equal

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
40	Revenue Difference	0	-11,954	10,473	2,149	4,021	1,552	-6,241
41	Difference / Tot Equal Revenue"	0.00%	-3.35%	7.03%	13.34%	10.95%	33.15%	-46.38%

Class Cost of Service Study ($000); Test Year 2022

Pipe Material	Diameter	Pipe Type	Footage	Total Cost Normalized 2021	2021 Normalized Cost per Foot	Total Cost Assuming Cost of 2 inch Plastic or Steel Pipe
Plastic	<=2"	Main Gas Plastic <=2"	38,130,280	$447,972,888	**$11.75**	$447,972,888
	> 2" to 4"	Main Gas Plastic > 2" to 4"	10,007,315	$216,884,890	$21.67	$117,570,755
	> 4" to 8"	Main Gas Plastic > 4" to 8"	2,405,646	$78,091,611	$32.46	$28,262,687
	>12" to 20"	Main Gas Plastic >12" to 20"	1,206	$23,279	$19.30	$14,169
Steel	<=2"	Main Gas Steel <=2"	1,455,989	$61,456,599	**$42.21**	$61,456,599
	> 2" to 4"	Main Gas Steel > 2" to 4"	1,734,247	$114,052,512	$65.76	$73,201,736
	> 4" to 8"	Main Gas Steel > 4" to 8"	1,453,655	$173,479,437	$119.34	$61,358,082
	> 8" to 10"	Main Gas Steel > 8" to 10"	10,106	$3,453,794	$341.76	$426,569
	>10" to 12"	Main Gas Steel >10" to 12"	415,500	$91,085,797	$219.22	$17,538,056
	>12" to 20"	Main Gas Steel >12" to 20"	170,284	$95,238,197	$559.29	$7,187,606
Cast Iron	> 2" to 4"	Main Gas Cast Iron > 2" to 4"	13,463	$353,192	$26.23	N/A
	> 4" to 8"	Main Gas Cast Iron > 4" to 8"	6,642	$242,453	$36.50	
	> 8" to 10"	Main Gas Cast Iron > 8" to 10"	8,105	$509,405	$62.85	
	>10" to 12"	Main Gas Cast Iron >10" to 12"	345	$97,913	$283.81	
	>12" to 20"	Main Gas Cast Iron >12" to 20"	771	$106,405	$138.01	
Total			**55,813,554**	**$1,283,048,371**	**$22.99**	**$814,989,149**

Type	Footage	Share
Plastic	50,544,447	90.56%
Steel	5,239,781	9.39%
Cast Iron	29,326	0.05%
Total	**55,813,554**	**100%**

Minimum System % Assuming
2 Inch Plastic or Steel >>> **63.5%**

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

2022 PROPOSED

REVENUE DECOUPLING MECHANISM RIDER

Section No. 5
Original Sheet No. 71

APPLICABILITY N

Applicable to bills for natural gas service provided under the Company's Residential (101), Small Commercial (102 & 108), and Large Commercial (118 & 125) schedules.

Not applicable to bills for natural gas service provided under the Company's Demand Billed (103 & 119), Small Interruptible (105 & 111), Medium Interruptible (106), Large Interruptible (120), Large Firm Transport (104), Interruptible Transport (107, 123, & 124), Negotiated Transport (114), and Small Volume Flex Interruptible Transport (157) schedules.

RIDER

For customers subject to this 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 therm natural gas consumption.

DETERMINATION OF RDM RIDER FACTORS

Annual RDM Rider Factor

Each year during the term of this rider the Company will calculate an RDM Rider factor for each applicable class. These factors will be based on revenues billed through December 31 and applied to usage from April 1 through March 31 of the following year. The RDM Rider factors are:

Residential (101)	\$0.000000 per therm
Small Commercial (102, 108)	\$0.000000 per therm
Large Commercial (118, 125)	\$0.000000 per therm

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	Annual RDM Rider Deferral = the sum of the 12 monthly RDM Rider Deferrals plus any under- or over-recovery of the previous Annual RDM Rider Deferral as described in item 3 of the RDM Rider Deferral Account on tariff sheet 5-72.
Forecasted Sales	Forecasted Usage = forecasted use in therms for the timeframe the RDM Rider factor to be in place. N

(Continued on Sheet No. 5-72)

DETERMINATION OF RDM RIDER FACTORS (Continued) N

The Annual RDM Rider factor to collect under-recovered revenues shall be capped at +10% of the total customer group base revenue (excluding CCRC revenues) for each of the rate classes. The RDM Rider factor to return over-recovered revenues shall not be capped.

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, Small Commercial, and Large Commercial services.

   Monthly RDM Rider Deferral = (FRC x C) – (FDC x Sales)

   For purposes of this section, the following definitions apply:

FRC	Fixed Revenue per Customer = Distribution charge revenues (excluding CCRC 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.
FDC	Fixed Distribution Charge = Average distribution charge for each month of test year. Expressed in dollars per therm.
Sales	Actual Sales = Actual billed sales for deferral month. Expressed in therms.

2. The Company will defer and amortize the Monthly RDM Deferrals in Account 182.3 or 254.

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

Northern States Power Company
Gas Utility - Minnesota

Residential RDM Rate Calculation

Residential TY 2022 Therms	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual
Residential Therms	76,129,388	60,634,255	48,782,089	27,205,344	13,621,217	8,822,740	6,648,156	6,881,609	8,897,227	22,571,394	43,762,685	65,343,004	389,299,108
Residential TY 2022 Dist. Chg	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	$0.285785	
Res TY 2022 Dist. Chg Rev	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual
Residential Revenue	$21,756,637	$17,328,361	$13,941,189	$7,774,879	$3,892,739	$2,521,407	$1,899,943	$1,966,661	$2,542,694	$6,450,566	$12,506,719	$18,674,051	$111,255,845
Residential TY CCRC Revenue	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
CCRC Rev @ $0.023902/therm	$1,819,645	$1,449,280	$1,165,989	$650,262	$325,574	$210,881	$158,904	$164,484	$212,662	$539,501	$1,046,016	$1,561,828	
Res Dist. Chg Rev w/o CCRC - 2022	$19,936,993	$15,879,081	$12,775,200	$7,124,617	$3,567,165	$2,310,526	$1,741,039	$1,802,176	$2,330,033	$5,911,064	$11,460,703	$17,112,222	
FRC = TY 2022 Fixed Revenue per Customer	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Res Dist. Chg Rev w/o CCRC - 2022	$19,936,993	$15,879,081	$12,775,200	$7,124,617	$3,567,165	$2,310,526	$1,741,039	$1,802,176	$2,330,033	$5,911,064	$11,460,703	$17,112,222	
2022 Cust Count	442,085	442,709	443,300	443,657	443,874	443,739	443,746	444,158	444,597	445,669	446,466	447,144	
FRC	$45.10	$35.87	$28.82	$16.06	$8.04	$5.21	$3.92	$4.06	$5.24	$13.26	$25.67	$38.27	
FDC = TY 2022 Fixed Distribution Chg	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Res Dist. Chg Rev w/o CCRC - 2022	$19,936,993	$15,879,081	$12,775,200	$7,124,617	$3,567,165	$2,310,526	$1,741,039	$1,802,176	$2,330,033	$5,911,064	$11,460,703	$17,112,222	
2022 Therms	76,129,388	60,634,255	48,782,089	27,205,344	13,621,217	8,822,740	6,648,156	6,881,609	8,897,227	22,571,394	43,762,685	65,343,004	
FDC	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	
2023 Residential - Full Decoupling (includes weather)*													
Allowed Rev = FRC * C	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC - Fixed Rev per Customer	$45.10	$35.87	$28.82	$16.06	$8.04	$5.21	$3.92	$4.06	$5.24	$13.26	$25.67	$38.27	
C = Actual Customer Count	447,799	448,283	448,710	448,878	448,882	448,539	448,342	448,557	448,835	449,783	450,495	451,108	
Allowed Revenue	$20,194,681	$16,079,009	$12,931,107	$7,208,460	$3,607,412	$2,335,519	$1,759,071	$1,820,025	$2,352,243	$5,965,630	$11,564,127	$17,263,925	$103,081,208
Actual Rev = FDC * Therms	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FDC - Fixed Dist. Charge	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	$0.261883	
Therms = Actual Sales	76,920,967	61,264,718	49,289,315	27,488,219	13,762,847	8,914,477	6,717,282	6,953,162	8,989,739	22,806,087	44,217,720	66,022,428	
Actual Revenue	$20,144,293	$16,044,188	$12,908,034	$7,198,697	$3,604,256	$2,334,550	$1,759,142	$1,820,915	$2,354,260	$5,972,526	$11,579,869	$17,290,151	$103,010,882
Deferral Calculation: Allowed Revenue - Actual Revenue													
Under / (Over) Collection	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Allowed Revenue	$20,194,681	$16,079,009	$12,931,107	$7,208,460	$3,607,412	$2,335,519	$1,759,071	$1,820,025	$2,352,243	$5,965,630	$11,564,127	$17,263,925	
Actual Revenue	$20,144,293	$16,044,188	$12,908,034	$7,198,697	$3,604,256	$2,334,550	$1,759,142	$1,820,915	$2,354,260	$5,972,526	$11,579,869	$17,290,151	
Under / (Over) Collection	$50,387	$34,821	$23,074	$9,763	$3,156	$969	-$71	-$890	-$2,017	-$6,897	-$15,742	-$26,227	$70,326

TY 2022 Base Revenue less CCRC	$160,593,402
Cap at 10% of Base Revenue	$16,059,340

Surcharge / (Refund) $	$70,326	
Carry-Over Balance	$0	
Apr 2024 - Mar 2025 Sales (Therms)	399,129,708	
RDM Rider Rate ($/Thm) - Apr 2024 - Mar 2025	$0.000176	Surcharge Factor

* This schedule uses forecasted sales and customers as a proxy to estimate 2023 decoupling deferrals.

Small Commercial Firm RDM Rate Calculation

Small Commercial Firm TY 2022 Therms	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual
Small Commercial Firm Therms	11,529,362	8,474,517	5,633,103	3,339,123	2,038,348	1,064,051	728,875	764,944	963,894	1,939,540	4,964,357	9,980,632	51,420,746
Small Commercial Firm TY 2022 Dist. Chg	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	$0.168025	
Small Commercial Firm TY 2022 Dist. Chg Rev	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual
Small Commercial Firm Revenue	$1,937,221	$1,423,931	$946,502	$561,056	$342,493	$178,787	$122,469	$128,530	$161,958	$325,891	$834,136	$1,676,996	$8,639,971
Small Commercial Firm TY CCRC Revenue	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Small Commercial Firm TY 2022 CIP Exempt Sales	626	1,310	1,866	1,773	1,072	515	440	342	590	843	735	887	
Small Commercial Firm Therms w/o CIP Exempt Sales	11,528,736	8,473,207	5,631,238	3,337,350	2,037,275	1,063,536	728,434	764,602	963,304	1,938,697	4,963,622	9,979,745	
CCRC Rev @ 0.023092/therm (w/o CIP exempt sales)	$275,560	$202,527	$134,598	$79,769	$48,695	$25,421	$17,411	$18,276	$23,025	$46,339	$118,640	$238,536	
Small Commercial Firm Dist. Chg Rev w/o CCRC - 2022	$1,661,661	$1,221,404	$811,904	$481,287	$293,798	$153,367	$105,058	$110,254	$138,933	$279,552	$715,496	$1,438,460	
FRC = TY 2022 Fixed Revenue per Customer	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Small Commercial Firm Dist. Chg Rev w/o CCRC - 2022	$1,661,661	$1,221,404	$811,904	$481,287	$293,798	$153,367	$105,058	$110,254	$138,933	$279,552	$715,496	$1,438,460	
2022 Cust Count	24,842	24,880	24,909	24,906	24,888	24,864	24,753	24,759	24,765	24,771	24,777	24,844	
FRC	$66.89	$49.09	$32.59	$19.32	$11.80	$6.17	$4.24	$4.45	$5.61	$11.29	$28.88	$57.90	
FDC = TY 2022 Fixed Distribution Chg	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Small Commercial Firm Dist. Chg Rev w/o CCRC - 2022	$1,661,661	$1,221,404	$811,904	$481,287	$293,798	$153,367	$105,058	$110,254	$138,933	$279,552	$715,496	$1,438,460	
2022 Therms	11,529,362	8,474,517	5,633,103	3,339,123	2,038,348	1,064,051	728,875	764,944	963,894	1,939,540	4,964,357	9,980,632	
FDC	$0.144124	$0.144127	$0.144131	$0.144136	$0.144136	$0.144135	$0.144137	$0.144134	$0.144138	$0.144133	$0.144127	$0.144125	
2023 Small Commercial Firm - Full Decoupling (includes weather)*													
Allowed Rev = FRC * C	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC - Fixed Rev per Customer	$66.89	$49.09	$32.59	$19.32	$11.80	$6.17	$4.24	$4.45	$5.61	$11.29	$28.88	$57.90	
C = Actual Customer Count	24,910	24,951	24,981	24,980	24,963	24,940	24,831	24,838	24,845	24,853	24,860	24,928	
Allowed Revenue	$1,666,248	$1,224,855	$814,246	$482,705	$294,683	$153,837	$105,387	$110,606	$139,383	$280,472	$717,884	$1,443,318	$7,433,622
Actual Rev = FDC * Therms	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FDC - Fixed Dist. Charge	$0.144124	$0.144127	$0.144131	$0.144136	$0.144136	$0.144135	$0.144137	$0.144134	$0.144138	$0.144133	$0.144127	$0.144125	
Therms = Actual Sales	11,550,629	8,490,145	5,643,481	3,345,274	2,042,099	1,066,008	730,216	766,351	965,668	1,943,114	4,973,511	9,999,045	
Actual Revenue	$1,664,726	$1,223,657	$813,400	$482,173	$294,339	$153,649	$105,252	$110,457	$139,189	$280,068	$716,815	$1,441,114	$7,424,838
Deferral Calculation: Allowed Revenue - Actual Revenue													
Under / (Over) Collection	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Allowed Revenue	$1,666,248	$1,224,855	$814,246	$482,705	$294,683	$153,837	$105,387	$110,606	$139,383	$280,472	$717,884	$1,443,318	
Actual Revenue	$1,664,726	$1,223,657	$813,400	$482,173	$294,339	$153,649	$105,252	$110,457	$139,189	$280,068	$716,815	$1,441,114	
Under / (Over) Collection	$1,522	$1,198	$845	$531	$343	$188	$136	$149	$194	$404	$1,069	$2,204	$8,785

TY 2022 Base Revenue less CCRC	$16,349,710
Cap at 10% of Base Revenue	$1,634,971

Surcharge / (Refund) $	$8,785	
Carry-Over Balance	$0	
Apr 2024 - Mar 2025 Sales (Therms)	51,937,441	
RDM Rider Rate ($/Thm) - Apr 2024 - Mar 2025	$0.000169	Surcharge Factor

* This schedule uses forecasted sales and customers as a proxy to estimate 2023 decoupling deferrals.

Large Commercial Firm RDM Rate Calculation

Large Commercial Firm TY 2022 Therms	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual
Large Commercial Firm Therms	31,360,093	25,696,286	24,104,729	12,271,278	6,793,567	4,757,768	3,458,420	3,934,550	4,731,161	12,015,908	21,022,183	28,450,193	178,596,136
Large Commercial TY 2022 Firm Dist. Chg	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	$0.167725	
Large Commercial Firm TY 2022 Dist. Chg Rev	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual
Large Commercial Firm Revenue	$5,259,872	$4,309,910	$4,042,966	$2,058,200	$1,139,451	$797,997	$580,064	$659,922	$793,534	$2,015,368	$3,525,946	$4,771,809	$29,955,037
Large Commercial Firm TY 2022 Dist. Chg Rev	$5,259,872	$4,309,910	$4,042,966	$2,058,200	$1,139,451	$797,997	$580,064	$659,922	$793,534	$2,015,368	$3,525,946	$4,771,809	
Large Commercial Firm TY 2022 CIP Exempt Sales	2,049	2,970	8,177	11,961	16,030	10,113	12,182	5,814	2,947	1,655	1,870	1,400	
Large Commercial Firm Therms w/o CIP Exempt Sales	31,358,044	25,693,316	24,096,552	12,259,317	6,777,536	4,747,656	3,446,238	3,928,737	4,728,214	12,014,253	21,020,314	28,448,793	
CCRC Rev @ 0.023092/therm	$749,520	$614,122	$575,956	$293,022	$161,997	$113,478	$82,372	$93,905	$113,014	$287,165	$502,428	$679,983	
Large Commercial Firm Dist. Chg Rev w/o CCRC - 2022	$4,510,352	$3,695,788	$3,467,010	$1,765,178	$977,454	$684,518	$497,692	$566,018	$680,520	$1,728,203	$3,023,518	$4,091,826	
FRC = TY 2022 Fixed Revenue per Customer	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Large Commercial Firm Dist. Chg Rev w/o CCRC - 2022	$4,510,352	$3,695,788	$3,467,010	$1,765,178	$977,454	$684,518	$497,692	$566,018	$680,520	$1,728,203	$3,023,518	$4,091,826	
2022 Cust Count	11,128	11,153	11,177	11,201	11,226	11,250	11,274	11,299	11,323	11,347	11,372	11,396	
FRC	$405.32	$331.37	$310.19	$157.59	$87.07	$60.85	$44.15	$50.09	$60.10	$152.30	$265.87	$359.06	
FDC = TY 2022 Fixed Distribution Chg	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	
Large Commercial Firm Dist. Chg Rev w/o CCRC - 2022	$4,510,352	$3,695,788	$3,467,010	$1,765,178	$977,454	$684,518	$497,692	$566,018	$680,520	$1,728,203	$3,023,518	$4,091,826	
2022 Therms	31,360,093	25,696,286	24,104,729	12,271,278	6,793,567	4,757,768	3,458,420	3,934,550	4,731,161	12,015,908	21,022,183	28,450,193	
FDC	$0.143825	$0.143826	$0.143831	$0.143846	$0.143879	$0.143874	$0.143907	$0.143858	$0.143838	$0.143826	$0.143825	$0.143824	
2023 Large Commercial Firm - Full Decoupling (includes weather)*													
Allowed Rev = FRC * C	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC - Fixed Rev per Customer	$405.32	$331.37	$310.19	$157.59	$87.07	$60.85	$44.15	$50.09	$60.10	$152.30	$265.87	$359.06	
C = Actual Customer Count	11,421	11,446	11,471	11,496	11,521	11,546	11,571	11,596	11,621	11,646	11,671	11,696	
Allowed Revenue	$4,629,109	$3,792,880	$3,558,206	$1,811,667	$1,003,140	$702,529	$510,803	$580,896	$698,430	$1,773,743	$3,103,014	$4,199,543	$26,363,960
Actual Rev = FDC * Therms	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FDC - Fixed Dist. Charge	$0.143825	$0.143826	$0.143831	$0.143846	$0.143879	$0.143874	$0.143907	$0.143858	$0.143838	$0.143826	$0.143825	$0.143824	
Therms = Actual Sales	32,120,192	26,319,107	24,688,975	12,568,707	6,958,228	4,873,086	3,542,245	4,029,915	4,845,834	12,307,147	21,531,715	29,139,763	
Actual Revenue	$4,619,673	$3,785,366	$3,551,043	$1,807,962	$1,001,146	$701,109	$509,755	$579,737	$697,014	$1,770,091	$3,096,802	$4,191,002	$26,310,699
Deferral Calculation: Allowed Revenue - Actual Revenue													
Under / (Over) Collection	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Allowed Revenue	$4,629,109	$3,792,880	$3,558,206	$1,811,667	$1,003,140	$702,529	$510,803	$580,896	$698,430	$1,773,743	$3,103,014	$4,199,543	
Actual Revenue	$4,619,673	$3,785,366	$3,551,043	$1,807,962	$1,001,146	$701,109	$509,755	$579,737	$697,014	$1,770,091	$3,096,802	$4,191,002	
Under / (Over) Collection	$9,436	$7,514	$7,164	$3,705	$1,994	$1,419	$1,048	$1,159	$1,416	$3,651	$6,213	$8,541	$53,261

TY 2022 Base Revenue less CCRC	$35,146,452
Cap at 10% of Base Revenue	$3,514,645

Surcharge / (Refund) $	$53,261	
Carry-Over Balance	$0	
Apr 2024 - Mar 2025 Sales (Therms)	189,845,667	
RDM Rider Rate ($/Thm) - Apr 2024 - Mar 2025	$0.000281	Surcharge Factor

* This schedule uses forecasted sales and customers as a proxy to estimate 2023 decoupling deferrals.

Other Revenue Impact

Tariff	Type	Present Charge	Proposed Charge	Unit	Present Revenue	Proposed Revenue	Difference
5.4	Excess Footage	$3.50	$9.10	66,708	$233,478	$607,043	$373,565
5.5	Excavation	$400	$685	479	$191,600	$328,115	$136,515
5.5	Service Ext.	$3.00	$8.90	30,623	$91,869	$272,545	$180,676
				Revenue Impact	**$516,947**	**$1,207,703**	**$690,756**

		Residential
Total Number of Work Orders (1 Work Order = 1 Service)		3,467
Total Actual Cost With Overheads	$	4,829,132
Base Cost per Service	**$**	**1,392.89**
Total Cost Per Service including Material & Meter Costs	**$**	**1,833.83**
Labor for removal		
Percentage of Setup Charge Labor to remove		42%
Total Labor Dollars for Removal	**$**	**585.01**
Other Items for Removal*	**$**	**565.63**
Incremental Cost Per Service	**$**	**683.18**
Incremental Cost Per Foot	**$**	**9.11**
Proposed Continuation of Excess Footage Charge	**$**	**9.10**

*These other items include meter credit capitalized at receipt, excess flow valves, service tees, meter brackets, straight risers, and meter assemblies.

2020 Winter Construction Burner Costs

Before January 1st Typically burn for 2 days
A burner requires 3 - 20 lb propane tanks to run for 2 days (20 lb tank = 5 gallons)

Process	Crew or Vehicles	Time to Do	Cost per Hour	Cost	Cost per Gallon	Gallons Used	Propane Cost	Totals
Set burner	Two man crew	1	$93.59	$93.59				
Re-tank burner	Two man crew	0	$93.59	$0.00				
Remove burner	Two man crew	0.5	$93.59	$46.80				
Total Labor				$140.39				
Labor Loading @ 76.87%				$107.91				
Labor w/ Loading				$248.30				$248.30
Vehicle & Equipment	Truck and Trailer	1.5	13.11	$19.67				$19.67
Propane Cost					2.02	15	$30.30	$30.30
Costs (before E&S)				$298.26				$298.26
E&S cost @ 42.78%				$127.60				$127.60
Total Cost				$425.86				$425.86

After January 1st - Typically burn for 3 days

Process	Crew or Vehicles	Time to Do	Cost per Hour	Cost	Cost per Gallon	Gallons Used	Propane Cost	Totals
Set burner	Two man crew	1	$93.59	$93.59				
Re-tank burner	Two man crew	1	$93.59	$93.59				
Remove burner	Two man crew	0.5	$93.59	$46.80				
Total Labor				$233.98				
Labor Loading @ 76.87%				$179.86				
Labor w/ Loading				$413.83				$413.83
Vehicle & Equipment	truck and trailer	2.5	13.11	$32.78				$32.78
Propane Cost					2.02	22.5	$45.45	$45.45
Costs (before E&S)				$492.06				$492.06
E&S cost @ 42.78%				$210.50				$210.50
Total Cost				$702.56				$702.56

* Please note, 90% of all burners are set after January 1st.

Before and after January Costs	Percentage	
$425.86	10%	$42.59
$702.56	90%	$632.30
		$674.89
Billing Labor		$10.00
Producing Bill		$0.11
Postage		$0.40
Total Cost of a Burner		**$685.39**

2019 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 2019

Average Cost per foot winter 2019 Services =	$28.07
Average Cost per foot non-Winter Months Services =	$19.16
Difference for Winter Construction =	$8.91

2021 Updates to Charges

Tariff							
Current Gas Charges			Updated Costs		Proposed Tariff Charge		
Service Extension	$400.00	per thaw unit	$685.39	per thaw unit	Thawing	$685.00	per thaw unit
	$3.00	plus per trench foot	$8.91	plus per trench foot	Service, Primary, or Secondary distribution extension	$8.90	per foot