EXHIBIT

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Direct Testimony and Schedules
Christopher J. Barthol

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
For Authority to Increase Rates for Natural Gas Service in North Dakota

Case No. PU-21-___
Exhibit___(CJB-1)

Class Cost of Service Study and Rate Design

September 1, 2021

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Exhibit 10 – Direct Testimony of Christopher J. Barthol (Class Cost of Service Study and Rate Design)
Northern States Power Company

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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.

Q. FOR WHOM ARE YOU TESTIFYING?

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

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 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 NSP's natural gas Class Cost of Service Study (CCOSS), proposed class revenue apportionment and proposed class rate design.

Q. PLEASE SUMMARIZE NSP'S CCOSS PROPOSAL.

A. The CCOSS is done on a forecasted 2022 calendar year embedded cost basis which functionalizes, classifies, and allocates budgeted plant and expenses in the test year on cost-causation principles. Other than the refinement of the calculation of certain allocators, the Company is not proposing any significant changes to the CCOSS methodology last approved by the North Dakota Public Service Commission. 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.

Q. PLEASE SUMMARIZE NSP'S CLASS REVENUE APPORTIONMENT AND RATE DESIGN PROPOSALS.

A. Using the CCOSS as a guide, along with the rate design objectives of continuity and moderation, I propose the same rate design structure that is currently approved with updated pricing components. These proposed rates are designed to recover the overall revenue requirement requested in this proceeding for the Company's natural gas utility operations in North Dakota, while moderating disproportionate rate increases on any customer class.

Q. WHAT ALLOCATION OF THE OVERALL COSTS OF SERVICE DOES THE CCOSS INDICATE FOR EACH CUSTOMER CLASS?

A. The CCOSS indicates a cost of service increase of 33.7 percent for Residential Firm service and 0.51 percent for Commercial and Industrial (C&I) Firm customers. The CCOSS indicates a decrease in the costs of service of 12.25 percent for Small Interruptible customers and 9.67 percent for Large Interruptible customers.

Q. HOW DO YOUR PROPOSED REVENUE INCREASES BY CLASS COMPARE TO THE CLASS ALLOCATION OF COSTS INDICATED BY THE CCOSS?

A. To mitigate the impact on Residential customers of the 33.7 percent cost allocation indicated by the CCOSS, I propose an increase of 15 percent, less than half of the needed increase indicated by the CCOSS. Mitigating the rate impact for Residential customers, however, requires proposed rates for non-residential customers that are higher than their cost. I propose a 10.5 percent increase for C&I Firm Service, and 10 percent increases for both Small and Large Interruptible Service. These modifications continue a moderate movement toward alignment of each class's rate recovery and costs of service.

Q. PLEASE SUMMARIZE NSP'S RATE DESIGN PROPOSAL.

A. The Company proposes to increase the monthly Residential Delivery Service Charge by $5.80, from $18.48 to $24.28. The Company also proposes to increase the C&I Firm Service Customer Charge from $30.00 to $35.00 and the volumetric Distribution Charge for C&I Firm Service customers from $0.10800 to $0.14627 per therm. Finally, the Company proposes to increase the Interruptible Service Customer Charge from $75.00 to $100.00, and to increase the Distribution Charge for Small Interruptible Service from $0.08800 to $0.11279 per therm and for Large Interruptible Service from $0.05120 to $0.07812 per therm. This rate design will provide the Company a reasonable opportunity to earn its authorized rate of return while ensuring rates remain reasonable.

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 the various service 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. Given the characteristics of gas utility costs, the primary objective of the CCOSS is to determine the total cost of service for each customer class, which 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 class revenue apportionment and rate design, which I discuss in more detail later in my Direct Testimony.

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 North Dakota 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 energy, 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. 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	C&I Firm	Small Int	Large Int	Total
Retail Revenue Requirement	$35,833	$32,063	$1,926	$5,789	$75,612
Present Retail Revenues	$26,797	$31,902	$2,195	$6,409	$67,303
Revenue Deficiency	$9,036	$161	-$269	-$620	$8,309
Deficiency %	33.72%	0.51%	-12.25%	-9.67%	12.35%

Q. THE COMPANY'S RATE APPLICATION STATES THAT THE COMPANY IS SEEKING AUTHORITY FROM THE COMMISSION TO INCREASE ITS NATURAL GAS REVENUES BY $7.059 MILLION, OR 10.49 PERCENT. WHY DOES THE CCOSS REFLECT AN $8.309 MILLION, OR 12.35 PERCENT OVERALL DEFICIENCY?

A. The total revenue deficiency in Table 1 includes a non-gas revenue deficiency of $7.059 million and the $1.25 million in manufactured gas plant (MGP) amortization which has been removed from the 2022 test year COSS and moved to the Cost of Gas (COG) Rider consistent with the Commission order and associated settlement in Case No. PU-18-156 (TCJA Settlement). In the TCJA settlement, it was agreed no portion of the $1.25 million MGP amortization will be included in the Company's test year following approval of the settlement, and that, rather, the costs of the MGP amortization would be recovered in the COG Rider.

Exhibit___(CJB-1), Schedule 4 provides a breakout of present and proposed base and non-gas revenues and my proposed apportionment of those revenues. Table 2 below also illustrates the breakout of the $7.059 million revenue deficiency and the $1.25 million MGP amortization.

Table 2

Composition of CCOSS Revenue Deficiency ($000)

Revenue Type	**Revenue Deficiency**
Base Rate (& other misc.)	$7,059
COG Rider (MGP Amortization)	$1,250
Total	$8,309

Q. PLEASE EXPLAIN THE CCOSS RESULTS.

A. The CCOSS indicates a cost-of-service increase of 33.7 percent for Residential Firm service and 0.51 percent for Commercial and Industrial (C&I) Firm customers. The CCOSS indicates a decrease in the costs of service of 12.25 percent for Small Interruptible customers and 9.67 percent for Large Interruptible customers.

Q. IS THE CCOSS INDICATED INCREASE FOR RESIDENTIAL CUSTOMERS UNEXPECTED?

A. No, for several reasons. The key drivers in this rate application are primarily associated with our gas distribution system (81 percent of our total plant in service in the test year is distribution plant) and are primarily driven by the addition of customers to our system. These drivers include distribution plant investments for safety-related work, improved reliability, serving new customers, and mandatory infrastructure relocations; the Fargo Capacity

Project, a new distribution main being constructed by the Company to increase the capacity of its distribution system in the Fargo and West Fargo area; and increased distribution operations and maintenance expenses which have been driven by inflation and the increase in Residential and C&I Firm customers.

Q. WHY DO YOU FEEL PROGRESS IS BEING MADE IN THE ALIGNMENT OF RESIDENTIAL RATES WITH THE COSTS TO SERVE?

A. In our last filed North Dakota gas rate case, the CCOSS indicated Residential rates would need to increase, on a percentage basis, four times the overall percentage increase to reflect cost-based rates. In comparison, the results of our current CCOSS indicate that Residential rates would need to increase approximately two and a half times the overall percentage increase to reflect cost-based rates. This result is due to gradual movement towards cost in final rates over time, and changes in current class allocators.

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. Table 3 provides a comparison of the primary allocators.

Table 3

Allocator Comparison (2022 TY vs. 2007 TY)

Allocator	Total	Res	C&I Firm	Sm Interr	Lg Interr
Customers – 2022	100.00%	84.95%	14.91%	0.10%	0.04%
Customers – 2007	100.00%	85.04%	14.65%	0.26%	0.05%
Design Day – 2022	100.00%	43.24%	56.76%	0.00%	0.00%
Design Day – 2007	100.00%	48.45%	51.55%	0.00%	0.00%
Mains, Overall – 2022	100.00%	69.47%	27.47%	0.54%	2.52%
Mains, Overall – 2007	100.00%	72.15%	24.27%	0.89%	2.69%
Meter & Regul – 2022	100.00%	67.54%	30.46%	1.05%	0.95%
Meter & Regul – 2007	100.00%	45.32%	50.58%	2.80%	1.29%
Sales, W/o Transp – 2022	100.00%	33.00%	47.98%	4.74%	14.28%
Sales, W/o Transp – 2007	100.00%	35.87%	43.01%	7.67%	13.45%
Sales, W/ Transp – 2022	100.00%	28.29%	46.30%	4.06%	21.34%
Sales, W/ Transp – 2007	100.00%	31.11%	37.31%	6.66%	24.92%
Gas Services Study – 2022	100.00%	68.96%	30.53%	0.51%	0.00%
Gas Services Study – 2007	100.00%	75.22%	23.32%	1.08%	0.38%

III. CCOSS PREPARATION

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 on cost-causation principles.

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 Halama.

Second, costs that can be directly attributed to a specific customer class 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 its contribution to Design Day demand — i.e., demand on the coldest winter day reasonably possible. 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) costs 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. Ideally, all customer costs would be collected through a class-specific monthly customer charge.

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.

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

A. Yes. The CCOSS conducted for this rate application is very similar to that performed by the Company in its last natural gas rate case (Case No. PU-06-525). Except for a few minor improvements to the meter and regulator, service, customer care, uncollectible, and late fee studies, 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 as Exhibit___(CJB-1), Schedule 3.

IV. EXTERNAL ALLOCATORS

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

A. In this section of my testimony I discuss the external allocators applied in the CCOSS. I divide the external allocators into distribution plant cost studies, other cost studies, and all other external allocators.

A. Distribution Plant Studies within CCOSS

Q. WHAT IS DISTRIBUTION PLANT?

A. Distribution Plant includes the pipelines, meters, and other infrastructure needed to deliver natural gas from the transmission system to customers' premises.

Q. WHAT ARE THE CATEGORIES OF DISTRIBUTION PLANT?

A. 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.

Q. PLEASE DESCRIBE HOW DISTRIBUTION PLANT AND REGULATOR STATIONS WERE CLASSIFIED.

A. Distribution Plant was classified as either customer- or demand-related. The National Association of Regulatory Utilities Commissioners (NARUC) Gas Distribution Rate Design manual defines customer-related distribution plant as services, meters, and regulators. Therefore, I have classified these plant items as customer related.

The NARUC manual further states that a portion of distribution mains may also be classified as customer 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 classified distribution mains utilizing a Minimum System Study, which I describe below.

The NARUC manual defines demand costs as capital costs associated with production, storage, and transmission plant and expenses; the demand cost of gas; and most of the distribution plant and expenses not classified as customer related. Therefore, I have classified Regulator Stations as demand-related and allocated these costs with an average and peak allocator which I will also explain later in my testimony.

Q. WHAT WERE THE RESULTS OF THIS CLASSIFICATION?

A. Table 4 below shows the amount of distribution plant by category and how they are classified:

Table 4

Distribution Plant by Category

Distribution Plant Category	2022 TY Plant in Service (000)	Demand Component	Customer Component
Distribution Mains	$108,873	X	X
Services	$56,569		X
Meters & Regulators	$15,453		X
Regulator Stations	$151	X	

1. Minimum System Study

Q. HOW DID YOU ALLOCATE COSTS FOR THE PORTION OF DISTRIBUTION MAINS NEEDED FOR BASIC CUSTOMER CONNECTIVITY?

A. I determined the appropriate allocation of costs for basic customer connectivity using a Minimum System Study.

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 an index utilized to escalate historical costs to the present.

Q. WHAT ARE THE COMPONENTS OF THE MINIMUM SYSTEM STUDY ALLOCATION OF MAINS?

A. The total cost of mains is split among Minimum System, Average Capacity, and Excess Capacity components.

Q. PLEASE DESCRIBE THE MINIMUM SYSTEM COMPONENT OF THE MINIMUM SYSTEM STUDY.

A. 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 North Dakota consisted of two-inch pipe, the initial plant investment would have been 66.1 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.

Q. PLEASE DESCRIBE THE AVERAGE CAPACITY COMPONENT OF THE MINIMUM SYSTEM STUDY.

A. Average Capacity costs are determined by taking the remaining 33.9 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 14,027,908 Dth) and dividing that by the Company's peak demand (2020-2021 Design Day Demand of 111,568 Dth – which is the most recent data available when performing the study) and multiplying that by 365 days in the year. The test year 2022 forecasted system load factor is 34.4 percent. Multiplying the 33.9 percent of the remaining total cost of mains by the system load factor leads to an Average Capacity of 11.7 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.

Q. PLEASE DESCRIBE THE EXCESS CAPACITY COMPONENT OF THE MINIMUM SYSTEM STUDY.

A. The Excess Capacity component is the remaining 22.2 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.

2. *Meter and Regulator Study*

Q. WHAT IS A METER AND REGULATOR STUDY?

A. A Meter and Regulator Study assigns meter costs and costs for pressure-regulating equipment to each class.

Q. PLEASE EXPLAIN THE METER AND REGULATOR STUDY YOU PERFORMED.

A. I gathered information 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, I was able to develop the total meter costs for each class and divide them 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 1.0. The weightings for the C&I, Small Interruptible, and Large Interruptible Classes are 2.57, 12.70, and 29.29, respectively. I applied the meter cost weighting for each class to the number of customers in each respective class in order to calculate the allocator for Meters and Regulators.

Q. DID YOU MODIFY THE METER AND REGULATOR STUDY SINCE THE COMPANY'S LAST GENERAL NATURAL GAS RATE CASE?

A. Yes, but only slightly. For the most part, the Meter and Regulator Study was conducted in the same manner as the last rate case. In the last rate case, classes were assigned a meter cost for the meter model most prevalent in each class. In this rate case, we are assigning the actual meter model and regulator costs to each customers' premises in order to derive the actual total meter and regulator costs by class, which provides for more precision in determining the weightings applied to the number of customers in each class.

3. Services Study

Q. WHAT IS A SERVICES STUDY?

A. A Services Study assigns gas services costs to each class.

Q. WHAT ARE SERVICES COSTS?

A. Services costs are the costs of service pipelines used to connect distribution mains to customers' premises.

Q. HOW DID YOU PERFORM THE SERVICES STUDY?

A. I gathered information on premise identification numbers, service pipe type, service pipe length, and class associated with each premise. I applied the cost per foot of each service pipe type to each class based on the service pipe types and footage used in each class. This calculation allowed me to determine the total cost of service pipes for each class.

I then divided the total cost by the number of customers in each class. Since the cost per customer for the residential class was lowest, that class received a weighting of 1.0. The weightings for the C&I, Small Interruptible, and Large Interruptible Classes are 2.52, 4.67, and 3.56, respectively.

I then calculated the allocator for gas services by applying the weightings of each class by the number of customers in each class.

Q. DID YOU MODIFY THE SERVICES STUDY SINCE THE LAST GENERAL NATURAL GAS RATE CASE (CASE NO. PU-06-525)?

A. Yes. In our last North Dakota rate case, which used a 2007 Test Year, we utilized weightings calculated in a service study conducted for our 2007 natural gas rate case in Minnesota (Docket No. G002/GR-06-1429). In this rate case, we are proposing to use gas services and costs that are specific to our North Dakota gas operations.

B. Other Cost Studies within CCOSS

Q. WHAT OTHER COST STUDIES DID YOU PERFORM?

A. I performed customer care, uncollectibles, and late payment studies.

1. Customer Care Studies

Q. WHAT CUSTOMER CARE STUDIES DID YOU PERFORM?

A. I performed two Customer Care studies 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.

Q. WHAT ARE FERC ACCOUNTS 903 AND 908, AS DEFINED BY THE UNIFORM SYSTEM OF ACCOUNTS?

A. 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.

Q. WHAT IS THE CUSTOMER RECORDS AND COLLECTIONS STUDY AND HOW IS IT UTILIZED IN THE CCOSS?

A. 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 1.0. The weightings for the C&I, Small Interruptible, and Large Interruptible Classes are 1.17, 61.08, and 61.08, respectively. 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.

Q. WHAT IS THE CUSTOMER INFORMATION STUDY AND HOW IS IT UTILIZED IN THE CCOSS?

A. 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 the C&I, Small Interruptible, and Large Interruptible Classes are 1.25, 63.71, and 29.86, respectively. 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.

Q. How were these costs associated with FERC Accounts 903 and 908 allocated in the last general natural gas rate case (Case No. PU-06-525)?

A. These expenses were simply allocated based on the number of customers within each customer class. In other words, unlike the Company's current CCOSS, costs that could have been directly assigned to a customer class were instead allocated based on the number of customers in each class.

Q. Why do the studies weight the customers differently in each class to derive the cost allocator?

A. Weighting customers recognizes that costs are incurred differently for each class.

2. *Uncollectibles Study*

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 (CASE NO. PU-06-525)?

A. These expenses were simply allocated based on the 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 net uncollectibles that were incurred for each class. This provides more accurate cost allocation than simply allocating these expenses based on the number of customers in each class.

3. Late Payment Study

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. HOW WERE THESE COSTS ALLOCATED IN THE COMPANY'S LAST GENERAL NATURAL GAS RATE CASE?

A. These costs were simply allocated with total present revenues associated with each customer class rather than by late fee revenue for each class

C. Other External Allocators

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

A. The remaining external allocators are the Design Day Demand and Sales allocators.

Q. PLEASE EXPLAIN THE DESIGN DAY DEMAND ALLOCATOR.

A. The Design Day Demand Allocator was calculated with each class's Design Day demand for the 2020-2021 heating season. This allocator is utilized to allocate various costs that are driven by the Design Day demands of each class and coincide with extreme weather conditions such as production plant, storage plant, and purchased gas. The Interruptible class does not have Design Day demand since they are curtailed when the gas system is experiencing peak loads.

Q. PLEASE EXPLAIN THE SALES ALLOCATORS.

A. There are two Sales Allocators: the "Sales without Transportation" and "Sales with Transportation" allocators. Using the Company's 2022 Test Year sales forecast as sponsored by Company witness Ms. Jannell Marks, the allocators are calculated using each class's share of sales. The Sales Without Transportation Allocator allocates costs not associated with our transportation customers, such as fuel associated with plant additions and the costs related to our legacy manufactured gas plant (MGP). The Sales with Transportation Allocator is utilized to allocate costs applicable to both sales and transportation customers, including the average capacity costs associated with mains, gas in storage, sales expenses, and sales expenses associated with labor.

D. Internal Allocators and Direct Assignments

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.

1. Primary Allocators

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.

Q. PLEASE DESCRIBE THE AVERAGE AND PEAK ALLOCATOR.

A. The Average and Peak Allocator is calculated from each class's portion of mains costs not allocated based on customer counts. This allocator is utilized to allocate demand-related costs such as transmission plant and regulator stations.

Q. PLEASE DESCRIBE THE MAINS, OVERALL ALLOCATOR.

A. The Mains, Overall Allocator is calculated from each class's total mains costs that are either allocated based on customer counts or demand. It is utilized to assign specific mains-related plant (depreciation, deferred taxes, and additions) and expenses (operations and maintenance, book depreciation, and taxes).

Q. PLEASE DESCRIBE THE PRODUCTION-STORAGE-TRANSMISSION-DISTRIBUTION ALLOCATOR.

A. The Production-Storage-Transmission-Distribution Allocator is calculated from each class's allocated total production, storage, transmission, and distribution plant that has already been assigned by external allocators. This allocator is utilized to allocate general and common plant to each class.

2. New Internal Allocators

Q. WHAT ARE THE NEW INTERNAL ALLOCATORS DEVELOPED SINCE THE LAST GENERAL NATURAL GAS RATE CASE?

A. The New Internal Allocators are a) Modified O&M Expense, b) ½ Rate Base / ½ Present Revenue, and c) Labor without A&G.

Q. PLEASE EXPLAIN THE MODIFIED O&M EXPENSE ALLOCATOR.

A. The Modified O&M Expense Allocator is calculated by taking the share of each class's combination of various O&M expenses and is used to allocate cash working capital. In the last general natural gas rate case, cash working capital was allocated with a number of different allocators. Since the nature of these costs is similar, it is reasonable to simplify the allocation of these costs with one allocator.

Q. PLEASE EXPLAIN THE ½ RATE BASE / ½ PRESENT REVENUE ALLOCATOR.

A. The ½ Rate Base / ½ Present Revenue Allocator is calculated from an equal share of each class's rate base allocated with external allocators and present revenues. This allocator is used to allocate several administration and general (A&G) expenses, such as injuries and claims, general advertising, rents, and miscellaneous general expenses. In the last general natural gas rate case, we utilized gross plant instead of rate base for one half of the allocator. I changed this allocator to be consistent between North Dakota and Minnesota and believe that rate base is a better component to the allocator since it takes into account all rate base items whereas gross plant omits depreciation and subtractions and additions to plant in service.

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.

V. REVENUE APPORTIONMENT

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

A. In this section, I discuss the test year revenues, the Company's North Dakota natural gas rate classes and the Company's class revenue apportionment proposal.

A. Test Year Revenues

Q. WHAT ARE THE TEST YEAR REVENUES AT PRESENT AND PROPOSED RATES?

A. The 2022 Test Year Revenues, applying present and proposed rates for the Company's Gas Utility-North Dakota jurisdiction, are $67.303 million and $74.362 million respectively. The $7.059 million difference between the two revenue levels is the base revenue deficiency described in Mr. Halama's testimony net of the MGP amortization's removal to the COG Rider. Present rates refer to the rates authorized in the Company's last natural gas rate case, Case No. PU-06-525. The proposed base rates are designed to produce an increase in retail revenues of $6.983 million and other miscellaneous revenues of $0.075 million. Forecasted sales and transportation service volumes for the 2022 Test Year, provided by Ms. Marks, were applied to both the present and proposed rates to obtain these Test Year Revenues. Present and proposed revenues are shown as base, fuel, and total revenues.

B. NSP's Natural Gas Services

Q. WHAT GENERAL CATEGORIES OF SERVICE DOES THE COMPANY PROVIDE TO ITS NATURAL GAS CUSTOMERS IN NORTH DAKOTA?

A. The Company provides sales service and transportation service. Sales service can be thought of as the more traditional "bundled" gas utility service offering, in that Xcel Energy procures wholesale natural gas for these customers, procures the interstate gas pipeline transportation, and distributes and resells the gas to these customers. Transportation service customers acquire their own gas supplies via an unregulated gas supplier and procure their own pipeline transportation to our town border station(s). We then deliver this third-party gas to the transportation customers' premises through the Company's gas distribution system.

Customers, whether sales or transportation, can take either firm or interruptible service. Firm service is typically not subject to curtailment and is priced to include the costs of providing this reliability. Service to customers taking interruptible service can be curtailed as needed to maintain system reliability and is priced to reflect both the lower degree of service and the competitive alternatives.

The vast majority of the Company's customers take firm, bundled sales service. Customers must meet certain eligibility criteria to qualify for and receive interruptible and/or transportation gas service.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S SERVICES.

A. The Company's Services are summarized in Table 5 below:

Table 5

Company's Natural Gas Services by Class

Firm Sales
Residential
Commercial and Industrial

Interruptible Sales
Small Interruptible
Large Interruptible

Transportation
Large Firm Transportation
Large Interruptible Transportation

C. Revenue Requirement Apportionment

Q. HOW WAS THE PROPOSED REVENUE REQUIREMENT APPORTIONMENT DEVELOPED?

A. The CCOSS was the starting point for the apportionment of the retail non-gas Test Year revenue requirement among the rate classes. As noted above, the CCOSS results indicate that customers under firm service should receive a rate increase, and the interruptible customers should receive a rate decrease.

The goal of setting rates to equal embedded costs of service, however, must be balanced with the other goals such as emphasizing value/competitive-based pricing for competitive services and moderating rate increases. My goal was to reflect the cost of service for each class while moderating bill impacts for most customers. (A summary page from the CCOSS showing the difference between current revenues and costs is provided in Exhibit___(CJB-1), Schedule 6.) Therefore, using the CCOSS as a guideline, I proposed more levelized increases among all of the rate classes, which mitigated the impact for Residential customers while at the same time moved Residential rates closer to their costs of service.

The CCOSS suggests that the Residential class would need to generate a 33.72 percent increase in revenues to match the costs to serve. My proposal moderates that with a 15.0 percent revenue increase for the Residential class, slightly higher than the overall 12.35 percent revenue increase. Again, the objective here is to moderate the impact to Residential customers while making progress towards recovering the costs of service indicated by the CCOSS. Moderating the billing impact on Residential customers in this way requires revenue increases to other classes which will result in revenues higher than their costs to serve. Specifically, I propose a 10.5 percent increase for the C&I Firm class and a 10.0 percent increase for the Interruptible class, classes which the CCOSS indicates should receive a rate reduction. By moderating the Residential Class increase and assigning some of the increase to other classes, the Company is levelizing the overall revenue requirement increases across its customer base, while still reflecting the overall comparative weighting indicated by the CCOSS results.

Q. WHY IS IT REASONABLE TO MITIGATE THE RATE INCREASE FOR RESIDENTIAL CUSTOMERS?

A. One of the objectives to be balanced in setting rates is to diminish the impact of CCOSS-based rate increases on any one customer class. A 33.7 percent rate increase for Residential customers would be significantly higher than the rate increase on any other class. Residential customers, especially those on fixed incomes, are particularly vulnerable to disproportionate rate increases. Additionally, most of the gap between the costs of service shown by the CCOSS and the present revenues in each class is due to the fact that in the last gas rate case, Residential customers were apportioned a lower percentage of their cost of service than other customer classes.

Q. DOES MITIGATING THE RATE INCREASE FOR RESIDENTIAL CUSTOMERS STILL LEAD TO REASONABLE RATES FOR OTHER CUSTOMER CLASSES?

A. Yes. To meet the Company's revenue requirement, mitigating the rate increase for Residential customers necessarily means a higher-than-indicated rate increase for non-Residential customers. However, the proposed rate increase for all other classes is still materially lower than the rate increase for Residential customers. The rate increases I propose for non-Residential customers are also lower on a percentage basis than the overall rate increase needed to meet the Company's revenue requirement. This approach appropriately balances competing interests, while moving the Company's rates incrementally towards the embedded cost of service.

Finally, I reviewed the apportionment to ensure that long-standing rate relationships between Firm and Interruptible rate classes, as well as between Sales Service and Transportation rate classes were maintained. This step helps to ensure that proposed class apportionments are appropriate. For example, Interruptible rates must be set at a discount relative to firm rates to reflect that interruptible service customers do not contribute to Design Day costs. In addition, the Large Interruptible distribution rates must be set at a discount relative to the Small Interruptible class to account for the economies of scale attendant to serving Large Interruptible customers. The resulting apportionment is provided in Exhibit___(CJB-1), Schedule 4 and the present and proposed rates are provided in Exhibit___(CJB-1), Schedule 7. Exhibit___(CJB-1), Schedule 6 contains a comparison of the proposed class rates and corresponding revenue increases to the revenue deficiencies indicated by the CCOSS, along with a proposed revenue increase by class.

Q. HOW ARE TRANSPORTATION CUSTOMERS TREATED IN THE APPORTIONMENT PROCESS?

A. Transportation customers are similar to our sales customers, except they procure their own gas supply. In order to assign Transportation customers a similar non-gas responsibility, I combine the Large Interruptible Transport customers with the Large Interruptible class and Firm Transport customers with the C&I Firm Class.

D. Overall Class Impacts

Q. PLEASE PROVIDE THE OVERALL CLASS IMPACTS OF THE COMPANY'S PROPOSED REVENUE APPORTIONMENT AND COMPARED TO THE CCOSS-INDICATED REVENUE APPORTIONMENT.

A. Table 6 provides the overall class impacts of the Company-proposed apportionment and compares it to the CCOSS-indicated apportionment.

Table 6

Revenue Apportionment

	($000)		
Customer Class	**Present Revenues**	**CCOSS Costs of Service**	**Proposed Revenue**
Residential	$26,797	$35,833	$30,817
% increase		33.72%	15.00%
C&I Firm	$31,902	$32,063	$35,256
% increase		0.51%	10.51%
Small & Large Interruptible	$8,604	$7,715	$9,464
% increase		-10.33%	10.00%
Total	$67,303	$75,612	$75,536
% increase		12.35%	12.23%

Q. PLEASE EXPLAIN THE DIFFERENCE IN TABLE 6 BETWEEN THE CCOSS COSTS OF SERVICE TOTAL OF $75.612 MILLION AND PROPOSED REVENUE TOTAL OF $75.536 MILLION.

A. The difference between the CCOSS total and Proposed Revenue total is attributed to the $0.076 million increase in late fees, winter construction, and excess footage charges and the proposed revenue has been reduced by this amount to account for this increase in revenues.

VI. RATE DESIGN

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

A. In this section of my testimony, I discuss the Company's overall objectives in designing rates and present the proposed rates by class to collect the total revenue requirement.

Q. WHAT ARE THE COMPANY'S PRIMARY PRICING OBJECTIVES IN DESIGNING NATURAL GAS RATES?

A. The primary natural gas rate design objectives are:

1) To collect total revenues sufficient to recover the Test Year cost of service;
2) To reasonably reflect the cost of providing service to each customer class, as supported by the CCOSS;
3) To encourage sound economic energy use;
4) To create rates that are easily understood and accepted by customers to the extent reasonably possible;
5) To moderate billing impacts;
6) To avoid any undue price discrimination; and
7) To provide flexibility through value-based pricing and service conditions, where needed to allow Xcel Energy's natural gas services to be competitive with other energy sources.

Q. PLEASE DESCRIBE EXHIBIT___(CJB-1), SCHEDULES 4, 5, AND 6.

A. Exhibit___(CJB-1), Schedule 4 summarizes the number of customers, therm sales by customer class and revenues from present and proposed rates. It also displays the amount and percentage increases between present and proposed revenues. The overall revenue increase of 12.2 percent includes a proposed 15.00 percent increase in Residential Firm Service, a 10.5 percent increase for the Commercial and Industrial (C&I) Firm Service class, and a 10 percent increase for Interruptible Service classes.

Exhibit___(CJB-1), Schedule 5, contains a more detailed report of the billing units by customer class, the present and proposed rates, and the corresponding present and proposed revenues.

Exhibit___(CJB-1), Schedule 6 provides the resulting revenues under the proposed Test Year revenue requirement compared to the class revenue requirements as determined by the CCOSS.

A. Revenue Recovery

Q. HOW ARE XCEL ENERGY'S CURRENT RATES STRUCTURED?

A. The Company's current rates are structured as either one- or two-part rates. One-part rates consist solely of a monthly fixed charge. Residential customers are charged a one-part rate called the "Delivery Services Charge," and for all other classes it is the "Customer Charge." All non-residential customers are charged a two-part rate consisting of a monthly fixed "Customer Charge" and a volumetric "Distribution Charge" applied to their use during the billing period.

Q. ARE THERE ANY OTHER COSTS RECOVERED FROM CUSTOMERS?

A. Yes, in addition to the fixed monthly charge and the volumetric Distribution Charge, the Company collects a Cost of Gas (COG) charge for the Company's purchase of wholesale gas which the Company delivers to its retail sales customers. The COG also includes the transportation and storage costs associated with the wholesale gas. Although the Test Year costs of gas are included as part of this proceeding, the fundamental rate design issues in this proceeding relate to recovery of the Company's non-gas costs of providing retail distribution service.

Q. DO YOU HAVE ANY SCHEDULES SUPPORTING THE COG?

A. Yes. Exhibit___(CJB-1), Schedule 9 contains a calculation of the COG used in Exhibit___(CJB-1), Schedule 5. This is a "snapshot" calculation from the Company's 2022 budget and is not necessarily indicative of the Company's current month COG factor.

Q. DO YOU PROPOSE ANY INCREASES TO THE RESIDENTIAL DELIVERY SERVICES CHARGE OR ANY CUSTOMER CHARGES?

A. Yes. The Company proposes an increase in the Residential Delivery Services Charge and the C&I Firm and Small Interruptible Customer Charges because the revenues generated by these charges are below the customer-driven costs of service in each of these customer classes. To achieve the desired rate structure and revenue apportionment, the Company also proposes to increase Distribution Charges in the C&I Firm and Interruptible customer classes.

B. Detailed Rate Design and Rate Impacts

Q. WHAT CHANGE IS XCEL ENERGY PROPOSING TO THE RESIDENTIAL CHARGE?

A. The Company is proposing to increase the monthly Residential Delivery Services Charge from $18.48 to $24.28.

Q. IS THIS RATE DESIGN CONSISTENT WITH PAST PRACTICE?

A. Yes. In the Company's 2004 North Dakota natural gas rate case (Case No. PU-04-578), the fixed monthly "Delivery Services" charge was instituted to recover all non-gas, local distribution revenue requirements attributable to the Residential class. This rate design was again approved by the Commission in our last general natural gas rate case (Case No. PU-06-525).

Q. WHAT ARE THE BENEFITS OF NOT HAVING AN ADDITIONAL VOLUMETRIC DISTRIBUTION CHARGE FOR RESIDENTIAL CUSTOMERS?

A. First, it is important to note that the non-gas cost portion of serving residential customers is mostly fixed. Further, without a volumetric Distribution Charge, Residential rates are more stable throughout the year, easier to understand, and more transparent. Additionally, decoupling residential revenues and gas sales supports customer conservation efforts.

Q. HOW ARE CUSTOMER BILLS MORE STABLE AND TRANSPARENT, AND EASIER TO UNDERSTAND WITHOUT A VOLUMETRIC DISTRIBUTION CHARGE?

A. Customer bills are more stable because they fluctuate less between the high-usage winter months and low-usage summer months. In the winter, when whether is cold, customers use considerably more natural gas. With a volumetric Distribution Charge in place, this would lead to much higher bills.

Charging customers a single Delivery Services Charge makes natural gas rates more transparent and understandable as customers know what that cost will be each month, and the monthly impact of proposed rate increases are transparent.

Q. HAS THE COMPANY SEEN EVIDENCE IN NORTH DAKOTA THAT ELIMINATION OF THE DISTRIBUTION CHARGE FOR RESIDENTIAL CUSTOMERS DISCOURAGED CONSERVATION?

A. No. This rate structure has been in place in North Dakota since 2005, and Residential use per customer in North Dakota has declined since then. It is important to remember that Residential customers still have a COG charge, which is based on the amount of natural gas consumed. The COG accounts for approximately 70 percent of Residential customers' bills so there still remains a strong customer incentive to conserve energy.

Q. WHAT IS THE BILL IMPACT OF THIS PROPOSAL FOR THE RESIDENTIAL CLASS?

A. Residential customers will experience a $5.80 increase in their bill. A comparison of bills for various usage levels under present and proposed rates is shown on Exhibit___(CJB-1), Schedule 8. The differences based on usage levels result only from changes in the COG.

C. C&I Firm Service

Q. WHAT CHANGES ARE YOU PROPOSING TO THE C&I FIRM SERVICE RATES?

A. I propose a $5.00 increase in the C&I Customer Charge. Moving from $30.00 per month to $35.00 per month. I also propose to increase the per therm Distribution Charge from $0.10800 to $0.14627.

D. Interruptible Sales Service

Q. WHAT CRITERIA WERE USED TO DESIGN THE COMPANY'S PROPOSED INTERRUPTIBLE GAS RATES?

A. The Company used two overall criteria to design the Interruptible gas rates.

The first criteria provides that Interruptible rates should reflect the anticipated value of service to the customer. This requires that Interruptible rates be set competitive with the cost of alternate fuels. The upper limit used for the Interruptible commodity pricing was the price of No. 2 fuel oil because most of these customers use No. 2 fuel oil as their primary alternate fuel. This criteria also requires a reasonable discount from firm prices because interruptible service is of lower value. If No. 2 fuel oil is priced higher than firm gas service, then the corresponding firm rates, less a reasonable discount, become the upper limits for Interruptible rates.

The second criteria applied to design Interruptible gas rates is that Interruptible customers should not be subsidized by other classes of service. Therefore, Interruptible rates should recover at least the Company's COG plus variable operating and maintenance expenses.

Q. HOW WERE THE INTERRUPTIBLE RATES DEVELOPED BASED ON THESE CRITERIA?

A. Xcel Energy is proposing an overall increase of 10.00 percent for the Interruptible Customer classes, which maintains a level of discount from firm service consistent with the discount in place today. The current Customer Charge for the Small Interruptible Service class is lower than the CCOSS average of customer-related expenses. Therefore, I am proposing to increase the Small Interruptible Customer Charge from $75 to $100. The proposed Distribution Charge for the Small Interruptible Service class is an increase from $0.08800 to $0.11279 per therm.

Table 7 below illustrates the current and proposed level of discount between Firm and Interruptible Sales Service.

Table 7

Average Bill Comparison-Commercial Firm and Interruptible Classes

Class	Avg Usage	Avg Bill - Present Rates	Avg Bill - Proposed Rates
Commercial Firm	7,519	$3,716	$4,087
Small Interruptible	7,519	$2,896	$3,185
% Discount		78%	78%
Commercial Firm	99,799	$48,956	53,817
Large Interruptible	99,799	$34,042	37,766
% Discount		70%	70%

Q. WHY IS IT IMPORTANT TO HAVE INTERRUPTIBLE CUSTOMERS?

A. The willingness of Interruptible customers to trade firm service for a discount, enhances system reliability and flexibility. In particular, since an Interruptible customer has agreed to not receive service at particular times, the Company's demand forecast can be reduced accordingly. This results in greater reliability, because the gas and pipeline capacity that would have ordinarily been needed to serve these customers can be used to serve other customers. This also reduces costs for all customers since the Company can now plan for less firm gas than would have otherwise been required.

Q. HOW DOES THE INTERRUPTIBLE RATE CLASS REDUCE COSTS FOR ALL CUSTOMERS?

A. The Interruptible rate class reduces costs for all customers in several ways. The throughput from these customers on our systems creates a higher load factor, resulting in lower gas costs, which flow through the COG. In addition, if this class of customers switched to Firm service, the Company could need to make additional capital investments and capacity purchases to firm up service to these customers.

Q. WILL THE PROPOSED INTERRUPTIBLE RATES RECOVER MORE THAN THE COSTS IMPOSED BY THESE CLASSES?

A. Yes. The proposed Interruptible rates would recover $1.987 million above the CCOSS revenue requirement for these customers, thereby reducing the residual costs that must be recovered from firm customers.

E. Firm and Interruptible Transportation Service

Q. WHAT CHANGES ARE YOU PROPOSING FOR THE TRANSPORTATION RATES?

A. Transportation rates are the same as the corresponding sales rates, except that Transportation customers pay a slightly higher Customer Charge to reflect the additional customer-related cost of serving such customers. This approach ensures that we will be indifferent to the customer's choice of gas procurement (*i.e.,* Xcel Energy sales gas or gas purchased from a third-party marketer). Therefore, my explanation of the proposed Customer Charges and Distribution Charges for sales customers also holds true for the corresponding Transportation rates. One nuance with the Transportation rates is that our Large Commercial Firm Transportation service customers pay a Distribution Demand Charge in addition to Customer and Distribution Charges. This per therm Distribution Demand Charge is applied to these customers' monthly billed demand.

Our Large Interruptible Transportation Service and Large Commercial Firm Transportation service customers have rate ranges set with minimum and maximum rates with their actual rates negotiated within that given range. For our Large Interruptible Transportation Service customers, we have set the maximum Distribution Charge at $0.07812 per therm. This rate is set at the Distribution Charge for our Large Interruptible sales service customers. For Large Commercial Firm Transportation service customers, we have increased the maximum Distribution and Demand Charges by the same percentage increase to our Commercial Firm Sales Service customers' distribution rate. We are proposing to increase the maximum Distribution and Demand charges to $0.04701 and $0.94263, respectively. We are not proposing a change in the minimum rates for either one of these services.

VII. GENERAL RULES AND REGULATIONS

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

A. The Company is proposing revisions to Section 5.3, Winter Construction Charges, of the General Rules and Regulations. These costs have not been revised since the Company's 2004 rate case.

A. Winter Construction Charges – Section 5.3

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 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 8 below.

Table 8

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 10. As a reminder, 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.

B. Other Revenue Impact

Q. HAVE YOU INCLUDED INCREASED OTHER REVENUES IN TOTAL REVENUES?

A. Yes. Other revenues have increased $56,273 as shown on page 1 of Exhibit___(CJB-1), Schedule 10. This increase in revenues is shown with the increase in late payment charges on page 5, lines 14 and 15 of Schedule 3 to my testimony. It is also shown on Schedules 4 and 6 to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues.

VIII. CONCLUSION

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. The purpose of a CCOSS is to provide a reasonable measure of the contribution each class makes to the Company's overall cost of service, with the ultimate goal of generating a cost basis from which class revenues and rates can be evaluated and refined. The Company has prepared a fully embedded CCOSS, and other than some minor allocator updates, this version of the CCOSS adheres to the same fundamental methods employed by the Company in its previous rate cases.

The Company's CCOSS is an appropriate rate making tool in this case and was used to inform a moderated class revenue apportionment. The Company maintained the prior rate design structure but updated rate components to collect the required revenue. Finally, the Company has also proposed various reasonable changes to its tariffs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company for Authority To Increase Rates for Natural Gas Service In North Dakota	))))	Case No. PU-21-____

AFFIDAVIT OF
Christopher J. Barthol

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

____
Christopher J. Barthol

Subscribed and sworn to before me, this 18 day of August, 2021.

____
Notary Public
My Commission Expires:

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

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
United States Marine Corps Machine Gunner	2000 - 2004

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, 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' share of the capacity, commodity, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study 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 (3) basic steps:

1. Functionalization – 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. Classification – 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. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' 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' 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 4 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 costs related to manufacturing, buying, or producing gas. These costs include pipeline or producer gas purchases and producing owned or peaking gas. Also includes operation and maintenance expenses.
Storage	360-363, 108(5), 190, 281-283 Net, 403, 408, 410.1, 411.1, 420	None	Includes costs related to storing off-peak gas for use during the winter-peaking months. Also includes operation and maintenance expenses.
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 3 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 was 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.

The Minimum Distribution 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	**66.1%**	**33.9%**

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 2 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.
- 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%.
    - There are 2 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 3 types of external allocators:
  - Capacity –related (sometimes referred to as Demand) allocators such as:
    - Design Day Demands – each firm class' 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 Exhibit___(CJB-1), Schedule 3, 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. 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. Commercial Firm
3. Small Interruptible
4. Large Interruptible

VII. 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 in 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.

VIII. 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' "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.

IX. 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' 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
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' 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

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

X. 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	12
	Other Production Exp	Misc. LNG Op Exp	5	27
	Distribution O&M Exp	Dispatching	5	36
1/2 Rt Base, 1/2 Pres Rev (Class only)	Admin & General	Injuries and Claims	6	16
		General Advertising	6	19
		Misc General Exp	6	20
		Rents	6	21
		Maint of Gen Plt	6	22
Average and Peak	Plant in Service	Transmission Plant	3	3
		Regulator Stations	3	4
	Accum Depr Rsv	Transmission Plant	3	18
		Regulator Stations	3	19
	Accum Defer IT	Transmission Plant	3	31
		Regulator Stations	3	32
	CWIP	Transmission Plant	4	3
		Regulator Stations	4	4
	Transmiss O&M Exp	Transmission Expense	5	29
	Distribution O&M Exp	Regulator Stations	5	30
	Book Deprec	Transmission Plant	6	34
		Regulator Stations	6	35
	Rl Estate & Prop Tax	Transmission Plant	7	3
		Regulator Stations	7	4
	Provis-Defer Inc Tax	Transmission Plant	7	17
		Regulator Stations	7	18

Allocator	Category	Item	Page	Line
Average and Peak (cont.)	Investment Tax Credit	Transmission Plant	7	31
		Regulator Stations	7	32
	Tax Depr & Removal	Transmission Plant	8	3
		Regulator Stations	8	4
Cust Inform Study	Cust Acctg & Inform	Asst Expense (w/o CIP)	6	6
Customers	Plant in Service	Mains - Minimum System	3	5
	Pres Other Oper Rev	Connection Charges	5	4
		Return Check Charges	5	5
		Connect Smart	5	6
		Incr Misc Serv	5	14
	Distribution O&M Exp	Other Property & Equipment	5	35
		Customer Installations	5	37
		Other Distribution	5	38
	Cust Acctg & Inform	Acct Superv	6	1
		Acct Meter Read	6	2
		Acct Misc	6	5
		Serv Instruct Adver	6	7
	Labor Allocator	Customer Accounting	8	31
		Cust Serv & Inform	8	32
CWIP	Pres Other Oper Rev	Contr In Aid Cons Tax Gr-Up	5	11
	Income Tax Additions	Avoided Tax Interest	8	17
	AFUDC	Total AFUDC	8	26
Design Day	Plant in Service	Production Plant (LPG)	3	1
		Storage Plant (LNG)	3	2
	Accum Depr Rsv	Production Plant (LPG)	3	16
		Storage Plant (LNG)	3	17
	Accum Defer IT	Production Plant (LPG)	3	29
		Storage Plant (LNG)	3	30
	CWIP	Production Plant (LPG)	4	1
		Storage Plant (LNG)	4	2
	Pres Other Oper Rev	Interchange Gas	5	7
		Other Gas Revenue	5	8
		Ltd Firm Sales - Rsrvs & Vols	5	9
		LP Sales to Others - MN	5	10
	Purchased Gas Exp	Propane	5	21
		Limited Firm	5	22
	Other Production Exp	Other Purchased Gas	5	24
		Misc. LPG Op Exp	5	25

Allocator	Category	Item	Page	Line
Design Day (cont.)	Book Deprec	Production Plant (LPG)	6	32
		Storage Plant (LNG)	6	33
	Rl Estate & Prop Tax	Production Plant (LPG)	7	1
		Storage Plant (LNG)	7	2
	Provis-Defer Inc Tax	Production Plant (LPG)	7	15
		Storage Plant (LNG)	7	16
	Investment Tax Credit	Production Plant (LPG)	7	29
		Storage Plant (LNG)	7	30
	Tax Depr & Removal	Production Plant (LPG)	8	1
		Storage Plant (LNG)	8	2
	Labor Allocator	Transmission	8	37
Direct Assign	Purchased Gas Exp	Commodity	5	19
		Demand	5	20
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	39
	Labor Allocator	Distribution	8	33
Excess Design Day	Plant in Service	Mains - Excess Capacity	3	7
Labor	Accum Defer IT	Non-Plant Related	3	41
	Non-Plt Asset-Liab	Non-Plant Assets & Liab	4	16
	Admin & General	Pension & Benefit-Direct	6	10
		Salaries	6	11
		Office & Supplies	6	12
		Admin Transfer Credit	6	13
		Outside Services	6	14
		Incentive Compensation	6	15
	Cust Service & Info	Amortizations	6	28
	Tot Rl Est & Prop Tax	Payroll Taxes	7	13
	Provis-Defer Inc Tax	Non-Plant Related	7	27
	Inc Tax Deductions	Other Timing Differences	8	21
		Meals	8	22
Late Pay (Class only)	Pres Other Oper Rev	Late Pay Penalties	5	3
	Prop Other Oper Rev	Incr Late Pay - Proposed	5	15

Allocator	Category	Item	Page	Line
Mains, Overall	Accum Depr Rsv	Mains	3	20
	Accum Defer IT		3	33
	CWIP		4	5
	Distribution O&M Exp		5	31
	Book Deprec		6	36
	Rl Estate & Prop Tax		7	5
	Provis-Defer Inc Tax		7	19
	Investment Tax Credit		7	33
	Tax Depr & Removal		8	5
Meter & Regul Study	Plant in Service	Meters	3	10
		House Regulators	3	11
	Accum Depr Rsv	Meters	3	22
		House Regulators	3	23
	Accum Defer IT	Meters	3	35
		House Regulators	3	36
	CWIP	Meters	4	7
		House Regulators	4	8
	Distribution O&M Exp	Meters	5	33
		House Regulators	5	34
	Book Deprec	Meters	6	38
		House Regulators	6	39
	Rl Estate & Prop Tax	Meters	7	7
		House Regulators	7	8
	Provis-Defer Inc Tax	Meters	7	21
		House Regulators	7	22
	Investment Tax Credit	Meters	7	35
		House Regulators	7	36
	Tax Depr & Removal	Meters	8	7
		House Regulators	8	8
Modified O&M Expense	Working Cash	Total Working Cash	4	35
Net Plant	Accum Defer IT	Accumulated Deferred Tax	3	40
	Admin & General	Property Insurance	6	9
	Provis-Defer Inc Tax	Tax Benefit Transfers	7	26
	Tax Depr & Removal	Tax Benefit Transfers	8	12
Other Production Exp	Labor Allocator	Production	8	35
Present Rev (Class only)	Admin & General	Regulatory Comm Exp	6	17
		Duplicate Charge Credit	6	18
	Amortizations	Rate Case Exp Amort	6	26

Allocator	Category	Item	Page	Line
Prod-Stor-Tran-Dis	Plant in Service	General Plant	3	13
		Common Plant	3	14
	Accum Depr Rsv	General Plant	3	25
		Common Plant	3	26
	Accum Defer IT	General Plant	3	38
		Common Plant	3	39
	CWIP	General & Common Plant	4	9
	Book Deprec	General Plant	6	41
		Common Plant	6	42
	Rl Estate & Prop Tax	General Plant	7	10
		Common Plant	7	11
	Provis-Defer Inc Tax	General Plant	7	24
		Common Plant	7	25
	Investment Tax Credit	General Plant	7	38
		Common Plant	7	39
	Tax Depr & Removal	General Plant	8	10
		Common Plant	8	11
Record & Coll Study	Cust Acctg & Inform	Acct Recrds & Coll	6	3
Sales, W/ Transp	Plant in Service	Mains - Average Capacity	3	6
	Gas In Storage	Total Gas in Storage	4	15
	Amortizations	MN Energy Policy Rider	6	25
	Sales Expense	Total Sales Expense	6	29
Sales, W/o CIP Exempt	Amortizations	CIP / DSM Amortization	6	24
Sales, W/o Transp	Miscellaneous	Fuel	4	19
	Other Prod Expense	MGP	5	26
Service Study	Plant in Service	Services	3	9
	Accum Depr Rsv		3	21
	Accum Defer IT		3	34
	CWIP		4	6
	Distribution O&M Exp		5	32
	Book Deprec		6	37
	Rl Estate & Prop Tax		7	6
	Provis-Defer Inc Tax		7	20
	Investment Tax Credit		7	34
	Tax Depr & Removal		8	6
Tran & Distrib	Material & Supply	Materials & Supplies	4	11
	Miscellaneous	Prepay: Insurance	4	17
		Prepay: Miscellaneous	4	18
Uncollectibles Study	Cust Acctg & Inform	Acct Uncollect	6	4

XI. 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 $9,036,233 and the cost-based customer charge for residential of $26.09 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 4 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 North Dakota 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

	Rate Base	ND	Res	C&I	Sm Int	Lg Int
1	Production	5,340	2,309	3,031	0	0
2	Storage	9,341	4,039	5,302	0	0
3	Transmission	3,909	1,536	2,031	55	287
4	Distribution	181,046	125,142	51,958	977	2,969
5	General	23,219	15,472	7,249	120	379
6	Common	0	0	0	0	0
7	**Total Plant In Service**	**222,855**	**148,497**	**69,571**	**1,152**	**3,635**
8	Production	2,375	1,027	1,348	0	0
9	Storage	8,040	3,476	4,563	0	0
10	Transmission	1,686	662	876	24	124
11	Distribution	59,632	41,166	17,374	318	773
12	General	11,241	7,491	3,509	58	183
13	Common	0	0	0	0	0
14	**Total Depreciation Reserve**	**82,973**	**53,822**	**27,671**	**399**	**1,081**
15	**Net Plant**	**139,882**	**94,675**	**41,900**	**752**	**2,555**
16	**Deductions** (Accum Def Inc Tax)	**19,783**	**13,524**	**5,827**	**116**	**315**
17	**Additions**	**4,128**	**1,826**	**1,645**	**116**	**541**
18	**Rate Base**	**124,227**	**82,977**	**37,718**	**752**	**2,780**

	Income Statement	ND	Res	C&I	Sm Int	Lg Int
19	**Present Retail Revenue**	**67,303**	**26,797**	**31,902**	**2,195**	**6,409**
20	**Present Other Oper Rev**	**550**	**338**	**211**	**0**	**1**
21	**Present Total Operating Rev**	**67,853**	**27,135**	**32,113**	**2,195**	**6,410**
	Operating & Maint Expenses					
22	Purchased Gas Expense	43,934	15,308	22,058	1,637	4,932
23	Other Purch Gas Exp	0	0	0	0	0
24	Other Production	1,885	682	957	61	186
25	Transmission	387	152	201	5	28
26	Distribution	5,129	3,813	1,229	19	68
27	Customer Accounting	1,613	1,286	267	43	17
28	Customer Service and Information	126	96	21	7	1
29	Administrative and General	2,508	1,622	774	27	84
30	Amortizations; Sales Expense	473	320	135	4	14
31	**Total Operating & Maint Exp**	**56,055**	**23,278**	**25,641**	**1,803**	**5,332**
32	Book Depreciation	6,892	4,483	2,284	33	92
33	Taxes Other Than Income Taxes	1,850	814	903	22	112
34	Prov For Deferred Inc Taxes	551	396	145	3	7
35	Net Investment Tax Credit	0	0	0	0	0
36	**Total Operating Expense**	**65,348**	**28,971**	**28,973**	**1,861**	**5,543**
37	State and Federal Income Taxes	-469	-1,192	455	75	193
38	**Total Expense**	**64,879**	**27,780**	**29,428**	**1,936**	**5,735**
39	AFUDC (Rev Credit)	0	0	0	0	0
40	**Total Operating Income**	**2,974**	**-644**	**2,685**	**259**	**674**
41	**Rate Base**	**124,227**	**82,977**	**37,718**	**752**	**2,780**
42	**Present Return on Rate Base**	**2.39%**	**-0.78%**	**7.12%**	**34.43%**	**24.25%**
43	**Present Return on Common Equity**	**0.88%**	**-5.15%**	**9.87%**	**61.87%**	**42.48%**
44	**Required Return on Rate Base**	**7.45%**	**7.45%**	**7.45%**	**7.45%**	**7.45%**
45	**Required Operating Income**	**9,255**	**6,182**	**2,810**	**56**	**207**
46	**Income Deficiency**	**6,281**	**6,826**	**125**	**-203**	**-467**
47	**Revenue Deficiency**	**8,309**	**9,036**	**161**	**-269**	**-620**
48	**Deficiency / Pres Retail Revenue**	**12.35%**	**33.72%**	**0.51%**	**-12.25%**	**-9.67%**

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

Equal Return vs Present

	Operating Revenue Requirement	ND	Res	C&I	Sm Int	Lg Int
1	Return On Rate Base	7.45%	7.45%	7.45%	7.45%	7.45%
2	Equalized Total Retail Rev	75,612	35,833	32,063	1,926	5,789
3	Present Total Retail Revenue	67,303	26,797	31,902	2,195	6,409
4	Revenue Deficiency	8,309	9,036	161	-269	-620
5	Deficiency / Pres Total Retail Rev	12.35%	33.72%	0.51%	-12.25%	-9.67%
	Internal Retail Revenue Reqt					
6	Customer Retail Revenue Requirement	20,607	16,222	4,244	100	41
7	Average Monthly Customers	60,991	51,811	9,092	63	25
8	Revenue Requirement $ / Mo / Cust	28.16	26.09	38.90	132.11	137.59
9	Capacity Retail Revenue Requirement	9,022	3,612	4,806	97	507
10	Annual Dkt Sales	14,027,908	3,969,079	6,494,932	569,913	2,993,984
11	Revenue Requirement $ / Dkt	0.64	0.91	0.74	0.17	0.17
	Capacity - Sub Classification					
12	Capacity - Base Revenue Requirement	2,332	652	1,076	97	507
13	Capacity - Seasonal Revenue Requirement	4,405	1,976	2,429	0	0
14	Peak Shaving Revenue Requirement	2,284	983	1,301	0	0
15	Base Rev Requirement $ / Dkt	0.17	0.16	0.17	0.17	0.17
16	Seasonal Rev Requirement $ / Dkt	0.31	0.50	0.37	0.00	0.00
17	Peak Shave Rev Requirement $ / Dkt	0.16	0.25	0.20	0.00	0.00
18	Energy Retail Revenue Requirement	1,973	630	943	92	308
19	Revenue Requirement $ / Dkt	0.14	0.16	0.15	0.16	0.10
20	Total Internal Retail Revenue Requirement	31,602	20,464	9,992	289	857
21	Revenue Requirement $ / Dkt	2.25	5.16	1.54	0.51	0.29
22	Revenue Requirement $ / Mo / Cust	43.18	32.91	91.59	381.68	2,855.15
	External Retail Revenue Reqt					
23	Capacity Revenue Requirement	9,398	3,910	5,487	0	0
24	Energy Revenue Requirement	34,537	11,397	16,571	1,637	4,932
25	Total External Revenue Requirement	43,934	15,308	22,058	1,637	4,932
26	Cap Revenue Requirement $ / Dkt	0.67	0.99	0.84	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.46	2.87	2.55	2.87	1.65
28	Tot Revenue Requirement $ / Dkt	3.13	3.86	3.40	2.87	1.65
	Total Retail Revenue Reqt					
29	Customer Revenue Requirement	20,607	16,222	4,244	100	41
30	Capacity Revenue Requirement	18,419	7,522	10,293	97	507
31	Energy Revenue Requirement	36,510	12,027	17,513	1,728	5,241
32	Total Revenue Requirement	75,536	35,771	32,050	1,926	5,789
33	Customer Revenue Reqt $ / Dkt	1.47	4.09	0.65	0.18	0.01
34	Demand Revenue Reqt $ / Dkt	1.31	1.90	1.58	0.17	0.17
35	Energy Revenue Reqt $ / Dkt	2.60	3.03	2.70	3.03	1.75
36	Total Revenue Reqt $ / Dkt	5.38	9.01	4.93	3.38	1.93

Proposed Return vs Present

		ND	Res	C&I	Sm Int	Lg Int
37	Proposed Total Retail Revenue	75,612	30,879	35,269	2,414	7,050
38	Revenue Deficiency	8,309	4,082	3,367	220	641
39	Deficiency / Pres Total Oper Revenue	12.35%	15.23%	10.55%	10.00%	10.00%

Proposed Return vs Equal

		ND	Res	C&I	Sm Int	Lg Int
40	Revenue Difference	0	-4,955	3,205	489	1,261
41	Difference / Tot Equal Revenue"	0.00%	-13.83%	10.00%	25.37%	21.78%

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

	Plant in Service	**FERC Accounts**	**Allocator**		**ND**	**Res**	**C&I**	**Sm Int**	**Lg Int**
1	**Production Plant (LPG)**	304, 305, 311	Design Day		5,340	2,309	3,031	0	0
2	**Storage Plant (LNG)**	360, 361, 362, 363	Design Day		9,341	4,039	5,302	0	0
3	**Transmission Plant**	365, 366, 367, 368, 369, 370, 371	Average and Peak		3,909	1,536	2,031	55	287
	Distribution Plant								
4	Regulator Stations	374, 375, 378, 379	Average and Peak		151	59	78	2	11
5	Mains - Minimum System	376	Customers	66.1%	71,961	61,130	10,727	75	29
6	Mains - Average Capacity	Split of 376	Sales, W/ Transp	11.7%	12,715	3,598	5,887	517	2,714
7	Mains - Excess Capacity	Split of 376	Excess Design Day	22.2%	24,196	10,906	13,290	0	0
8	Mains - Total	376			108,873	75,634	29,904	591	2,743
9	Services	380	Service Study		56,569	39,011	17,269	222	67
10	Meters	381	Meter & Regul Study		11,957	8,076	3,642	125	114
11	House Regulators	383	Meter & Regul Study		3,496	2,361	1,065	37	33
12	Total Distribution Plant	Subtotal			181,046	125,142	51,958	977	2,969
13	**General Plant**	390-399	Prod-Stor-Tran-Dis		23,219	15,472	7,249	120	379
14	**Common Plant**	390-399	Prod-Stor-Tran-Dis		0	0	0	0	0
15	**Gas Plant in Service**	Total			**222,855**	**148,497**	**69,571**	**1,152**	**3,635**
	Accum Depr Reserve	**FERC Accounts**							
16	**Production Plant (LPG)**	108(1)	Design Day		2,375	1,027	1,348	0	0
17	**Storage Plant (LNG)**	108(5)	Design Day		8,040	3,476	4,563	0	0
18	**Transmission Plant**	108(7)	Average and Peak		1,686	662	876	24	124
	Distribution Plant								
19	Regulator Stations	108(8)	Average and Peak		0	0	0	0	0
20	Mains	108(8)	Mains, Overall		26,961	18,730	7,405	146	679
21	Services	108(8)	Service Study		26,071	17,979	7,959	102	31
22	Meters	108(8)	Meter & Regul Study		5,813	3,926	1,770	61	55
23	House Regulators	108(8)	Meter & Regul Study		786	531	239	8	8
24	Total Distribution Plant	Sub-total			59,632	41,166	17,374	318	773
25	**General Plant**	108(9)	Prod-Stor-Tran-Dis		11,241	7,491	3,509	58	183
26	**Common Plant**	108(9)	Prod-Stor-Tran-Dis		0	0	0	0	0
27	**Total Accum Depr**	Sub-total			**82,973**	**53,822**	**27,671**	**399**	**1,081**
28	**Net Plant**	Total			**139,882**	**94,675**	**41,900**	**752**	**2,555**
	Subtractions to Net Plant								
	Accum Deferred Inc Tax	**FERC Accounts**							
29	**Production Plant (LPG)**	190, 281, 282, 283 Net	Design Day		-65	-28	-37	0	0
30	**Storage Plant (LNG)**	190, 281, 282, 283 Net	Design Day		-424	-183	-240	0	0
31	**Transmission Plant**	190, 281, 282, 283 Net	Average and Peak		717	282	373	10	53
	Distribution Plant								
32	Regulator Stations	190, 281, 282, 283 Net	Average and Peak		0	0	0	0	0
33	Mains	190, 281, 282, 283 Net	Mains, Overall		7,798	5,417	2,142	42	196
34	Services	190, 281, 282, 283 Net	Service Study		7,408	5,109	2,262	29	9
35	Meters	190, 281, 282, 283 Net	Meter & Regul Study		2,054	1,388	626	21	20
36	House Regulators	190, 281, 282, 283 Net	Meter & Regul Study		195	132	59	2	2
37	Total Distribution Plant	Sub-total			17,455	12,045	5,088	95	227
38	**General Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis		1,873	1,248	585	10	31
39	**Common Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis		0	0	0	0	0
40	Accumulated Deferred Tax	283	Net Plant		-93	-63	-28	0	-2
41	Non-Plant Related	190 & 282 Net	Labor		319	223	86	2	7
42	**Total Subtractions**	Total			**19,783**	**13,524**	**5,827**	**116**	**315**

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

Additions to Net Plant

		FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
	CWIP							
1	Production Plant (LPG)		Design Day	4	2	2	0	0
2	Storage Plant (LNG)		Design Day	4	2	2	0	0
3	Transmission Plant	107	Average and Peak	0	0	0	0	0
4	Regulator Stations	107	Average and Peak	0	0	0	0	0
5	Mains	107	Mains Overall	74	51	20	0	2
6	Services		Service Study	0	0	0	0	0
7	Meters		Meter & Regul Study	0	0	0	0	0
8	House Regulators	107	Meter & Regul Study	0	0	0	0	0
9	General & Common Plant	Sub-total	Prod-Stor-Tran-Dis	106	70	33	1	2
10	Total CWIP	Sub-total		188	125	58	1	4
11	**Materials & Supplies**	154, 155, 156	Tran & Distrib	150	103	44	1	3
	Gas In Storage							
12	Total Gas in Storage	Total	Sales, W/ Transp	2,098	594	971	85	448
13	**Non-Plant Assets & Liab**	Total	Labor	1,463	1,025	396	10	32
	Miscellaneous	**FERC Accounts**						
14	Prepay: Insurance	165	Tran & Distrib	0	0	0	0	0
15	Prepay: Miscellaneous	165	Tran & Distrib	-419	-287	-122	-2	-7
16	Fuel	176	Sales, W/o Transp	0	0	0	0	0
17	Total Miscellaneous			-419	-287	-122	-2	-7
	Working Cash							
18	Total Working Cash	Total	Modified O&M Expense	648	266	298	21	62
19	**Total Additions**	Sub-total		**4,128**	**1,826**	**1,645**	**116**	**541**
20	**Total Rate Base**	Sub-Total		**124,227**	**82,977**	**37,718**	**752**	**2,780**
21	**Common Rate Base (@ 52.54%)**			**65,269**	**43,596**	**19,817**	**395**	**1,461**
22	Customer Component			86,867	68,338	18,171	235	123
23	Demand Component			34,726	13,870	18,319	406	2,132
24	Energy Component			2,634	770	1,228	111	525

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

INCOME STATEMENT

Operating Revenue (Cal Month)

	Retail Revenue		Allocator	ND	Res	C&I	Sm Int	Lg Int
1a	**Present Retail Rev**	480, 481, 482, 484	Direct Assign	**67,303**	**26,797**	**31,902**	**2,195**	**6,409**
1b	**Proposed Retail Rev**		Direct Assign	**75,536**	**30,817**	**35,256**	**2,414**	**7,050**
2	**Retail Rev Increase**			**8,234**	**4,020**	**3,354**	**219**	**641**
	Other Operating Revenue							
3	Late Pay Penalties	488, 495	Late Pay; Mod Pres Rev	155	116	38	0	1
4	Connection Charges	488, 495	Customers	114	97	17	0	0
5	Return Check Charges	488, 495	Customers	7	6	1	0	0
6	Connect Smart	488, 495	Customers	3	3	0	0	0
7	Interchange Gas	488, 495	Design Day	63	27	36	0	0
8	Other Gas Revenue	488, 495	Design Day	90	39	51	0	0
9	Ltd Firm Sales - Rsrvs & Vols	488, 495	Design Day	120	52	68	0	0
10	LP Sales to Others - MN	488, 495	Design Day	0	0	0	0	0
11	Contr In Aid Cons Tax Gr-Up	488, 495	CWIP	0	0	0	0	0
12	Other - Miscellaneous	488, 495	1/2 Dsgn Day, 1/2 Ener	-2	-1	-1	0	0
13	**Tot Other Oper Rev - Pres**	**Sub-total**		**550**	**338**	**211**	**0**	**1**
14	Incr Misc Serv		Customers	56	48	8	0	0
15	Incr Late Pay - Proposed		Late Pay; Mod Pres Rev	19	14	5	0	0
16	**Tot Other Oper Rev - Prop**			**626**	**400**	**224**	**1**	**1**
16a	**Total Oper Rev - Present**	Total		**67,853**	**27,135**	**32,113**	**2,195**	**6,410**
16b	**Total Oper Rev - Proposed**			**76,162**	**31,217**	**35,479**	**2,415**	**7,051**
18	**Operating Rev Increase**			**8,309**	**4,082**	**3,367**	**220**	**641**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	FERC Accounts	Alloc	ND	Res	C&I	Sm Int	Lg Int
19	Commodity	728, 804, 805, 808, 858	Direct Assign	34,537	11,397	16,571	1,637	4,932
20	Demand	804, 808, 858	Direct Assign	9,398	3,910	5,487	0	0
21	Propane		Design Day	0	0	0	0	0
22	Limited Firm	728	Design Day	0	0	0	0	0
23	Total Purchases	Sub-total		43,934	15,308	22,058	1,637	4,932
	Other Production Expense							
24	Other Purchased Gas		Design Day	65	28	37	0	0
25	Misc. LPG Op Exp	710, 733, 735, 736, 742, 759	Design Day	498	215	283	0	0
26	MGP	735	Sales, W/o Transp	1,250	413	600	59	179
27	Misc. LNG Op Exp	840, 841, 842, 843	1/2 Dsgn Day, 1/2 Ener	72	26	37	1	8
28	Total Other Production Expense			1,885	682	957	61	186
29	**Transmission Expense**	850-865	Average and Peak	387	152	201	5	28
	Distribution Expense							
30	Regulator Stations	875, 877, 889, 891	Average and Peak	20	8	10	0	1
31	Mains	874, 887	Mains, Overall	1,926	1,338	529	10	49
32	Services	892	Service Study	1,010	696	308	4	1
33	Meters	878, 893	Meter & Regul Study	-205	-138	-62	-2	-2
34	House Regulators	878, 893	Meter & Regul Study	27	18	8	0	0
35	Other Property & Equipment	881	Customers	198	168	29	0	0
36	Dispatching	871	1/2 Dsgn Day, 1/2 Ener	108	39	56	2	12
37	Customer Installations	879	Customers	211	179	31	0	0
38	Other Distribution	880	Customers	1,333	1,133	199	1	1
39	Supervision & Engineering	870, 885	Dist Exp, w/o Sup & Eng	502	373	120	2	7
40	Total Distribution Expense	Sub-total		5,129	3,813	1,229	19	68

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

INCOME STATEMENT

Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
1	Acct Superv	901	Customers	4	3	1	0	0
2	Acct Meter Read	902	Customers	559	475	83	1	0
3	Acct Recrds & Coll	903	Record & Coll Study	748	572	117	43	17
4	Acct Uncollect	904	Uncollectibles Study	300	234	65	0	0
5	Acct Misc	905	Customers	3	2	0	0	0
6	Asst Expense (w/o CIP)	908	Cust Inform Study	126	96	21	7	1
7	Serv Instruct Adver	909	Customers	0	0	0	0	0
8	Tot Cust Acctg & Inform			1,738	1,381	288	51	18
	Admin & General							
9	Property Insurance	924	Net Plant	52	35	16	0	1
10	Pension & Benefit-Direct	926	Labor	647	453	175	4	14
11	Salaries	920	Labor	748	524	202	5	17
12	Office & Supplies	921	Labor	534	374	144	4	12
13	Admin Transfer Credit	922	Labor	-428	-300	-116	-3	-9
14	Outside Services	923	Labor	158	110	43	1	3
15	Incentive Compensation	920 + other	Labor	0	0	0	0	0
16	Injuries and Claims	925	1/2 Rt Base, 1/2 Pres Rev;	130	69	50	3	8
17	Regulatory Comm Exp	928	Present Retail Revenue	1	1	1	0	0
18	Duplicate Charge Credit	929	Present Retail Revenue	0	0	0	0	0
19	General Advertising	930	1/2 Rt Base, 1/2 Pres Rev;	3	2	1	0	0
20	Misc General Exp	930	1/2 Rt Base, 1/2 Pres Rev;	29	15	11	1	2
21	Rents	931	1/2 Rt Base, 1/2 Pres Rev;	633	338	246	12	37
22	Maint of Gen Plt	935	1/2 Rt Base, 1/2 Pres Rev;	1	1	0	0	0
23	Total A & G Expense			2,508	1,622	774	27	84
	Cust Service & Info							
24	CIP/DSM & Amortizations	407.3 + CIP	Sales, W/o CIP Exempt	0	0	0	0	0
25	MN Energy Policy Rider	407	Sales, W/ Transp	0	0	0	0	0
26	Instructional Advertising	407	Present Retail Revenue	24	9	11	1	2
27	Total Customer Service Info	Sub-total		24	9	11	1	2
28	Amortizations		Labor	440	308	119	3	10
	Sales Expense							
29	Sales, Econ Dvlp & Other	912	Sales, W/ Transp	10	3	5	0	2
30	Total Sales Expense	Sub-total		10	3	5	0	2
31	**Total O&M Expense**			**56,055**	**23,278**	**25,641**	**1,803**	**5,332**

Book Depreciation

		FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
32	**Production Plant (LPG)**	403	Design Day	386	167	219	0	0
33	**Storage Plant (LNG)**	403	Design Day	469	203	266	0	0
34	**Transmission Plant**	403	Average and Peak	67	26	35	1	5
	Distribution Plant							
35	Regulator Stations	403	Average and Peak	0	0	0	0	0
36	Mains	403	Mains, Overall	2,236	1,553	614	12	56
37	Services	403	Service Study	1,790	1,235	547	7	2
38	Meters	403	Meter & Regul Study	398	269	121	4	4
39	House Regulators	403	Meter & Regul Study	97	65	29	1	1
40	Total Distribution Plant			4,521	3,122	1,311	24	63
41	**General Plant**	403	Prod-Stor-Tran-Dis	1,448	965	452	7	24
42	**Common Plant**	403, 404	Prod-Stor-Tran-Dis	0	0	0	0	0
43	**Total Book Deprec**	Sub-total		**6,892**	**4,483**	**2,284**	**33**	**92**

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

INCOME STATEMENT

	Real Estate & Prop Taxes	FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
1	**Production Plant (LPG)**	408	Design Day	144	62	82	0	0
2	**Storage Plant (LNG)**	408	Design Day	0	0	0	0	0
3	**Transmission Plant**	408	Average and Peak	31	12	16	0	2
	Distribution Plant							
4	Regulator Stations	408	Average and Peak	1,412	555	734	20	104
5	Mains	408	Mains, Overall	0	0	0	0	0
6	Services	408	Service Study	0	0	0	0	0
7	Meters	408	Meter & Regul Study	0	0	0	0	0
8	House Regulators	408	Meter & Regul Study	0	0	0	0	0
9	Total Distribution Plant	Sub-total		1,412	555	734	20	104
10	**General Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0
11	**Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0
12	**Total Rl Est & Prop Tax**	Sub-total		**1,587**	**629**	**832**	**20**	**106**
13	Payroll Taxes	408	Labor	263	184	71	2	6
14	**Tot Non-Income Taxes**			**1,850**	**814**	**903**	**22**	**112**
	Provision-Defer Inc Tax	**FERC Accounts**						
15	**Production Plant (LPG)**	410.1, 411.1	Design Day	-30	-13	-17	0	0
16	**Storage Plant (LNG)**	410.1, 411.1	Design Day	-29	-12	-16	0	0
17	**Transmission Plant**	410.1, 411.1	Average and Peak	-12	-5	-6	0	-1
	Distribution Plant							
18	Regulator Stations	410.1, 411.1	Average and Peak	0	0	0	0	0
19	Mains	410.1, 411.1	Mains, Overall	154	107	42	1	4
20	Services	410.1, 411.1	Service Study	243	168	74	1	0
21	Meters	410.1, 411.1	Meter & Regul Study	69	47	21	1	1
22	House Regulators	410.1, 411.1	Meter & Regul Study	12	8	4	0	0
23	Total Distribution Plant	Sub-total		479	330	141	3	5
24	**General Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	101	67	31	1	2
25	**Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	0	0	0	0	0
26	Tax Benefit Transfers	410.1, 411.1	Net Plant	0	0	0	0	0
27	Non-Plant Related	410.1, 411.1	Labor	42	29	11	0	1
28	**Tot Prov Defer Inc Tax**	Total		**551**	**396**	**145**	**3**	**7**
	Investment Tax Credit	**FERC Accounts**						
29	**Production Plant (LPG)**	420	Design Day	0	0	0	0	0
30	**Storage Plant (LNG)**	420	Design Day	0	0	0	0	0
31	**Transmission Plant**	420	Average and Peak	0	0	0	0	0
	Distribution Plant							
32	Regulator Stations	420	Average and Peak	0	0	0	0	0
33	Mains	420	Mains, Overall	0	0	0	0	0
34	Services	420	Service Study	0	0	0	0	0
35	Meters	420	Meter & Regul Study	0	0	0	0	0
36	House Regulators	420	Meter & Regul Study	0	0	0	0	0
37	Total Distribution Plant	Sub-total		0	0	0	0	0
38	**General Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0
39	**Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0
40	**Net Invest Tax Credit**	Sub-total		**0**	**0**	**0**	**0**	**0**
41	**Total Operating Exp**	Sub-total		**65,348**	**28,971**	**28,973**	**1,861**	**5,543**
42a	**Pres Op Inc Before Inc Tax**	Total		**2,505**	**-1,836**	**3,140**	**334**	**867**
42b	**Prop Op Inc Before Inc Tax**	Total		**10,814**	**2,246**	**6,507**	**553**	**1,508**

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

INCOME STATEMENT

	Tax Deprec & Removal	FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
1	**Production Plant (LPG)**	Not Applicable	Design Day	279	120	158	0	0
2	**Storage Plant (LNG)**	Not Applicable	Design Day	373	161	212	0	0
3	**Transmission Plant**	Not Applicable	Average and Peak	43	17	22	1	3
	Distribution Plant							
4	Regulator Stations	Not Applicable	Average and Peak	0	0	0	0	0
5	Mains	Not Applicable	Mains, Overall	2,773	1,926	762	15	70
6	Services	Not Applicable	Service Study	3,069	2,116	937	12	4
7	Meters	Not Applicable	Meter & Regul Study	770	520	235	8	7
8	House Regulators	Not Applicable	Meter & Regul Study	108	73	33	1	1
9	Total Distribution Plant	Sub-total		6,720	4,636	1,966	36	82
10	**General Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0
11	**Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0
12	Tax Benefit Transfers	Not Applicable	Net Plant	2,184	1,478	654	12	40
13	**Total Tax Depreciation**	Total		**9,598**	**6,413**	**3,012**	**49**	**125**
	Present Return							
	Inc Tax Additions	**FERC Accounts**						
14	Total Book Depr Exp	from another page		6,892	4,483	2,284	33	92
15	Provision for Deferred	from another page		550.98	396	145	3	7
16	Net Inv Tax Credit	from another page		0	0	0	0	0
17	Avoided Tax Interest	Not Applicable	CWIP	52	35	16	0	1
18	Total Tax Additions	Sub-total		7,495	4,914	2,445	36	99
	Inc Tax Deductions							
19	Tax Depr & Removal Exp	from another page		9,598	6,413	3,012	49	125
20	Debt Interest Expense	Calculation	; Mod Rate Base	2,398	1,601	728	15	54
21	Other Timing Differences	Not Applicable	Labor	-88	-62	-24	-1	-2
22	Meals		Labor	13	9	4	0	0
23	Total Tax Deductions			11,921	7,962	3,720	63	177
23a	**Pres Taxable Net Income**	Calculation		**-1,921**	**-4,883**	**1,865**	**308**	**789**
23b	**Prop Taxable Net Income**			**6,388**	**-801**	**5,232**	**527**	**1,430**
24a	**Pres Inc Tax, @24.40%**	Calculation		**-468.86**	**-1,192**	**455**	**75**	**193**
24b	**Prop Inc Tax, @24.40%**			**1,559**	**-196**	**1,277**	**129**	**349**
25a	**Pres Preliminary Return**			2,974	-644	2,685	259	674
25b	**Prop Preliminary Return**			9,255	2,441	5,230	425	1,159
26	**Total AFUDC**	Not Applicable	CWIP	**0**	**0**	**0**	**0**	**0**
27a	**Pres Total Return**	Total	; Mod Rate Base	**2,974**	**-644**	**2,685**	**259**	**674**
27b	**Prop Total Return**		; Mod Rate Base	**9,255**	**2,441**	**5,230**	**425**	**1,159**
28a	**Pres % Return on Rate Base**	Calculation		**2.39%**	**-0.78%**	**7.12%**	**34.43%**	**24.25%**
28b	**Prop % Return on Rate Base**			**7.45%**	**2.94%**	**13.87%**	**56.52%**	**41.68%**
29a	**Pres Common Return**			**576**	**(2,246)**	**1,957**	**244**	**621**
29b	**Prop Common Return**			**6,857**	**840**	**4,502**	**410**	**1,105**
30a	**Pres % Ret on Common Rt Bs**			**0.88%**	**-5.15%**	**9.87%**	**61.87%**	**42.48%**
30b	**Prop % Ret on Common Rt Bs**			**10.51%**	**1.93%**	**22.72%**	**103.90%**	**75.66%**
	Labor Allocator	**FERC Accounts**						
31	Customer Accounting	Labor Portion of O&M Accounts	Customers	395	336	59	0	0
32	Cust Serv & Inform	Labor Portion of O&M Accounts	Customers	9	8	1	0	0
33	Distribution	Labor Portion of O&M Accounts	Dist Exp, w/o Sup & Eng	1,851	1,376	444	7	25
34	Admin & General	Labor Portion of O&M Accounts	Labor w/o A&G	1,409	987	381	10	31
35	Production	Labor Portion of O&M Accounts	Other Production Exp	346	125	176	11	34
36	Sales	Labor Portion of O&M Accounts	Sales, W/ Transp	1	0	0	0	0
37	Transmission	Labor Portion of O&M Accounts	Design Day	82	36	47	0	0
38	Total			4,093	2,867	1,108	28	90

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

ALLOCATORS

	Internal Allocators	ND	Res	C&I	Sm Int	Lg Int
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**35.77%**	**51.53%**	**2.03%**	**10.67%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**53.31%**	**38.88%**	**1.93%**	**5.88%**
3	Average and Peak (Mains)	36,911	14,504	19,177	517	2,714
4	Average and Peak	**100.00%**	**39.29%**	**51.95%**	**1.40%**	**7.35%**
5	CWIP	**100.00%**	**66.71%**	**30.88%**	**0.50%**	**1.91%**
6	Dist Exp, w/o Sup & Eng	4,628	3,440	1,109	17	62
7	Dist Exp, w/o Sup & Eng	**100.00%**	**74.34%**	**23.96%**	**0.36%**	**1.33%**
8	Distribution Plant	**100.00%**	**69.12%**	**28.70%**	**0.54%**	**1.64%**
9	Gas Plant In Service	**100.00%**	**66.63%**	**31.22%**	**0.52%**	**1.63%**
10	Labor	**100.00%**	**70.05%**	**27.06%**	**0.68%**	**2.21%**
11	Mains, Overall	**100.00%**	**69.47%**	**27.47%**	**0.54%**	**2.52%**
12	Modified O&M Expense	54,794	22,536	25,201	1,784	5,274
13	Modified O&M Expense	**100.00%**	**41.13%**	**45.99%**	**3.26%**	**9.62%**
14	Net Plant	**100.00%**	**67.68%**	**29.95%**	**0.54%**	**1.83%**
15	Other Production Exp	**100.00%**	**36.16%**	**50.74%**	**3.22%**	**9.88%**
16	Prod-Stor-Tran-Dis	199,636	133,026	62,322	1,032	3,256
17	Prod-Stor-Tran-Dis	**100.00%**	**66.63%**	**31.22%**	**0.52%**	**1.63%**
18	Rate Base	**100.00%**	**66.79%**	**30.36%**	**0.61%**	**2.24%**
19	Rt Base, w/o Work Cash	123,579	82,711	37,420	731	2,718
20	Rt Base, w/o Work Cash	**100.00%**	**66.93%**	**30.28%**	**0.59%**	**2.20%**
21	Transmission & Distribution	184,955	126,678	53,989	1,032	3,256
22	Tran & Distrib	**100.00%**	**68.49%**	**29.19%**	**0.56%**	**1.76%**
23	Labor w/o A&G	2,685	1,881	726	18	59
24	Labor w/o A&G	**100.00%**	**70.05%**	**27.06%**	**0.68%**	**2.21%**
	Component Allocators					
25	Mod Present Rev	**400.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
26	Mod Rate Base	**400.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
27	1/2 Mod Rt Bs, 1/2 Mod Pres Rv	**400.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Northern States Power Company
Natural Gas Utility - State of North Dakota
Class Cost of Service Study ($000); Test Year 2022

Case No. PU-21-___
Exhibit___(CJB-1), Schedule 3

ALLOCATORS

External Allocators

			ND	Res	C&I	Sm Int	Lg Int
	Customer-Related						
1	Bills		731,886	621,727	109,101	758	300
2	Meter & Regul Weightings			1.00	2.57	12.70	29.29
3	Meter (Wtd Bills)		920,507	621,727	280,370	9,624	8,786
4	Service Weightings			1.00	2.52	4.67	3.56
5	Service (Wtd Bills)		901,562	621,727	275,225	3,541	1,069
6	Records & Collect Weightings			1.00	1.17	61.08	61.08
7	Records & Collect (Wtd Bills)		813,752	621,727	127,398	46,302	18,325
8	Cust Information Weightings			1.00	1.25	63.71	29.86
9	Cust Information (Wtd Bills)		815,433	621,727	136,459	48,289	8,958
10	Customers		100.00%	84.95%	14.91%	0.10%	0.04%
11	Meter & Regul Study		100.00%	67.54%	30.46%	1.05%	0.95%
12	Service Study		100.00%	68.96%	30.53%	0.39%	0.12%
13	Record & Coll Study		100.00%	76.40%	15.66%	5.69%	2.25%
14	Uncollectibles Study		100.00%	78.11%	21.81%	0.08%	0.00%
15	Cust Inform Study		100.00%	76.24%	16.73%	5.92%	1.10%
	Energy-Related						
16	Cal Yr Sales Dkt, W/o Trans		12,027,377	3,969,079	5,770,711	569,913	1,717,674
17	Transportation Dkt		2,000,531	0	724,221	0	1,276,310
18	Cal Yr Sales Dkt, W/ Trans	34.4%	14,027,908	3,969,079	6,494,932	569,913	2,993,984
19	CIP Exempt Dkt		0	0	0	0	0
20	Sales Dkt, W/o CIP Exempt		14,027,908	3,969,079	6,494,932	569,913	2,993,984
21	Sales, W/o Transp		100.00%	33.00%	47.98%	4.74%	14.28%
22	Sales, W/ Transp		100.00%	28.29%	46.30%	4.06%	21.34%
23	Sales, W/o CIP Exempt		100.00%	28.29%	46.30%	4.06%	21.34%
	Demand-Related						
24	Design Day Demand Dkt		111,568	48,241	63,327	0	0
25	Avg Daily Firm Dkt, W/ Trans		28,669	10,874	17,794	0	0
26	Excess Design Day		82,900	37,367	45,533	0	0
27	Design Day		100.00%	43.24%	56.76%	0.00%	0.00%
28	Excess Design Day		100.00%	45.07%	54.93%	0.00%	0.00%
	Miscellaneous (only alloc to class, not component)						
29	Present Retail Revenue		67,303	26,797	31,902	2,195	6,409
30	Gross Receipts Tax		100.00%	56.19%	36.38%	4.35%	2.45%
31	Present Retail Revenue		100.00%	39.82%	47.40%	3.26%	9.52%
32	Late Payment Penalty		100.00%	74.55%	24.55%	0.21%	0.70%

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

Capital Structure		**Rate**	**Ratio**	**Wtd Cost**
1	Long Term Debt	4.10%	47.03%	1.93%
2	Short Term Debt	1.09%	0.43%	0.00%
3	Debt Total	4.07%	47.46%	1.93%
4	Preferred Stock	0.00%	0.00%	0.00%
5	Common Equity	10.50%	52.54%	5.52%
6	Required Rate of Return		100.00%	7.45%
7	ND Combined State & Fed Tax Rate	24.40%		
8	1 / (1 - Tax Rate) Factor	132.28%		
9	Tax Rate / (1 - Tax Rate) Factor	32.28%		

Northern States Power Company
Natural Gas Utility - State of North Dakota
Proposed Revenue Apportionment

Case No. PU-21-___
Exhibit___(CJB-1), Schedule 4

	Rate Code	Avg Cust.	Dkt Sales	Present Revenues			Proposed Revenue			Increase					
				Base	Fuel	Total	Base	Fuel	Total	Base	%	Fuel	%	Total	%
Firm Service															
Residential	401	51,811	3,969,079	11,489,515	15,307,684	$26,797,199	$15,096,434	$15,720,345	$30,816,779	$3,606,919	31.4%	$412,661	2.7%	$4,019,580	15.0%
Commercial and Industrial	410	9,092	6,494,932	9,843,987	22,057,904	$31,901,891	$12,597,710	$22,657,878	$35,255,588	$2,753,723	28.0%	$599,974	2.7%	$3,353,697	10.5%
Total Firm Service		60,903	10,464,011	21,333,502	37,365,588	$58,699,090	$27,694,144	$38,378,223	$66,072,367	$6,360,642	29.8%	$1,012,635	2.7%	$7,373,277	12.6%
Interruptible Service															
Small C&I	404	63	569,913	558,374	1,636,515	$2,194,889	$718,605	$1,695,768	$2,414,374	$160,231	28.7%	$59,253	3.6%	$219,485	10.0%
Large C&I	405	25	2,993,984	1,476,382	4,932,326	$6,408,708	$1,938,780	$5,110,911	$7,049,691	$462,398	31.3%	$178,585	3.6%	$640,983	10.0%
Total Interruptible Service		88	3,563,897	2,034,756	6,568,841	$8,603,597	$2,657,385	$6,806,679	$9,464,064	$622,629	30.6%	$237,838	3.6%	$860,467	10.0%
Total Retail		60,991	14,027,908	23,368,258	43,934,429	$67,302,687	$30,351,530	$45,184,902	$75,536,431	$6,983,271	29.9%	$1,250,473	2.8%	$8,233,744	12.2%

Other Gas Revenues

	Present Total	Proposed Total	Increase Total	%
Late Pay Penalties	$155,340	$174,344	$19,004	12.2%
Connection Charges	$113,904	$170,177	$56,273	49.4%
Return Check Charges	$6,516	$6,516	$0	0.0%
Connect Smart	$3,011	$3,011	$0	0.0%
Interchange Gas	$63,229	$63,229	$0	0.0%
Other Gas Revenue	$90,112	$90,112	$0	0.0%
Ltd Firm Sales - Rsrvs & Vols	$120,420	$120,420	$0	0.0%
LP Sales to Others - MN	$0	$0	$0	0.0%
Contr In Aid Cons Tax Gr-Up	$0	$0	$0	0.0%
Other - Miscellaneous	-$2,148	-$2,148	$0	0.0%
Total Other Gas Revenues	$550,384	$625,660	$75,277	13.7%
Total Retail Sales and Other Revenues	**$67,853,071**	**$76,162,092**	**$8,309,021**	**12.2%**

Residential Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Delivery Services Charge	621,727		$ 18.48	$ 11,489,515	$ 24.28	$ 15,096,434	$ 3,606,919	
Distribution Charge		39,690,789	$ -	$ -	$ -	$ -	$ -	
MGP		39,690,789	$ -	$ -	$ 0.01040	$ 412,661	$ 412,661	
Cost of Gas Charge								
Summer (Apr-Oct)		8,443,492	$ 0.33921	$ 2,864,147	$ 0.33921	$ 2,864,147		
Winter (Nov-Mar)		31,247,297	$ 0.39823	$ 12,443,537	$ 0.39823	$ 12,443,537		
Total		39,690,789	$ 0.38567	$ 15,307,684	$ 0.38567	$ 15,307,684	$ -	
Average Customers	51,811							
			Total	$ 26,797,199		$ 30,816,779	$ 4,019,580	15.00%

Commercial and Industrial Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	109,101		$30.00	$ 3,273,030	$35.00	$ 3,818,535	$ 545,505	
Distribution Charge		64,949,321	$ 0.10800	$ 7,014,527	$ 0.14627	$ 9,499,942	$ 2,485,415	
Discount		7,242,210	$ (0.06125)	$ (443,570)	$ (0.09952)	$ (720,767)	$ (277,197)	
MGP		57,707,111	$ -	$ -	$ 0.01040	$ 599,974	$ 599,974	
Cost of Gas Charge								
Summer (Apr-Oct)		15,634,588	$ 0.33921	$ 5,303,463	$ 0.33921	$ 5,303,463		
Winter (Nov-Mar)		42,072,522	$ 0.39823	$ 16,754,441	$ 0.39823	$ 16,754,441		
Cost of Gas Charge		57,707,111	$ 0.38224	$ 22,057,904	$ 0.38224	$ 22,057,904	$ -	
Average Customers	9,092							
			Total	$ 31,901,891		$ 35,255,588	$ 3,353,697	10.50%

Small Interruptible Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	758		$ 75.00	$ 56,850	$ 100.00	$ 75,800	$ 18,950	
Distribution Charge		5,699,135	$ 0.08800	$ 501,524	$ 0.11279	$ 642,805	$ 141,281	
MGP		5,699,135	$ -	$ -	$ 0.01040	$ 59,253	$ 59,253	
Cost of Gas Charge		5,699,135	$ 0.28715	$ 1,636,515	$ 0.28715	$ 1,636,515	$ -	
Average Customers	63							
			Total	$ 2,194,889		$ 2,414,374	$ 219,485	10.00%

Large Interruptible Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	300		$ 275.00	$ 82,500	$ 275.00	$ 82,500	$ -	
Distribution Charge		29,939,839	$ 0.05120	$ 1,532,920	$ 0.07812	$ 2,338,900	$ 805,980	
Discount		12,763,099	$ (0.01089)	$ (139,038)	$ (0.03781)	$ (482,620)	$ (343,582)	
MGP		17,176,740	$ -	$ -	$ 0.01040	$ 178,585	$ 178,585	
Cost of Gas Charge		17,176,740	$ 0.28715	$ 4,932,326	$ 0.28715	$ 4,932,326	$ -	
Average Customers	25							
			Total	$ 6,408,708		$ 7,049,691	$ 640,983	10.00%

($000s)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Customer Class		**Present Revenues**	**MGP Revenues**	**Revenue Deficiency Indicated by CCOSS (Less MGP)**	**Revenue Deficiency Indicated by CCOSS (With MGP)**	**Total Effect of Proposed Rates**	**Difference Between CCOSS Revenue Deficiency and Proposed Rates**
Residential	$ increase	$26,797	$413	$8,624	$9,036	$4,020	$5,017
	% increase			32.18%	33.72%	15.0%	18.7%
Commercial	$ increase	$31,902	$600	($439)	$161	$3,354	($3,192)
	% increase			-1.37%	0.51%	10.5%	-10.0%
Interruptible Service	$ increase	$2,195	$59	($328)	($269)	$219	($488)
(Small Volume)	% increase			-14.95%	-12.25%	10.0%	-22.3%
Interruptible Service	$ increase	$6,409	$179	($798)	($620)	$641	($1,261)
(Large Volume)	% increase			-12.46%	-9.67%	10.0%	-19.7%
Other Revenues	$ increase	$550				$75	
	% increase						
Total	$ increase	$67,853	$1,250	$7,059	$8,309	$8,309	$0
	% increase			10.40%	12.25%	12.25%	0.0%

Rate Design - Class Impact by Rate Component

		(1)	(2)	(3)	(4)
Customer Class			**Overall Impacts of Proposed Rates**		
		Present Revenues	**Delivery / Basic Service Charges**	**Distribution Charges**	**Total Effect of All Changes**
Residential	$ increase	$26,797	$3,607	$413	$4,020
	% increase		13.5%	1.5%	15.0%
Commercial	$ increase	$31,902	$546	$2,808	$3,354
	% increase		1.7%	8.8%	10.5%
Small Interruptible	$ increase	$2,195	$19	$201	$219
	% increase		0.9%	9.1%	10.0%
Large Interruptible	$ increase	$6,409	$0	$641	$641
	% increase		0.0%	10.0%	10.0%
Total	$ increase	$67,303	$4,171	$4,062	$8,234
	% increase		6.2%	6.0%	12.2%

	Present Rates	Proposed Rates
Residential Firm Service		
Delivery Services Charge	$18.48 / Month	$24.28 / Month
Cost of Gas	$0.38567 /Therm	$0.38567 /Therm
MGP amortization	$0.00000 /Therm	$0.01040 /Therm
C&I Firm Service		
Basic Service Charge	$30.00 /Month	$35.00 /Month
Distribution Charge	$0.10800 /Therm	$0.14627 /Therm
Cost of Gas	$0.38224 /Therm	$0.38224 /Therm
MGP amortization	$0.00000 /Therm	$0.01040 /Therm
Small C&I Interruptible Service		
Basic Service Charge	$75.00 /Month	$100.00 /Month
Distribution Charge	$0.08800 /Therm	$0.11279 /Therm
Cost of Gas	$0.28715 /Therm	$0.28715 /Therm
MGP amortization	$0.00000 /Therm	$0.01040 /Therm
Large C&I Interruptible Service		
Basic Service Charge	$275.00 /Month	$275.00 /Month
Distribution Charge	$0.05120 /Therm	$0.07812 /Therm
Cost of Gas	$0.28715 /Therm	$0.28715 /Therm
MGP amortization	$0.00000 /Therm	$0.01040 /Therm

RESIDENTIAL FIRM SERVICE

Use (Therms)	Bill Amount (Present)	Bill Amount (Proposed)	Increase	Percent
0	$18.48	$24.28	$5.80	31.4%
10	$22.34	$28.24	$5.90	26.4%
20	$26.19	$32.20	$6.01	22.9%
30	$30.05	$36.16	$6.11	20.3%
40	$33.91	$40.12	$6.22	18.3%
50	$37.76	$44.08	$6.32	16.7%
64	$43.10	$49.56	$6.46	15.0%
75	$47.41	$53.99	$6.58	13.9%
100	$57.05	$63.89	$6.84	12.0%
200	$95.61	$103.49	$7.88	8.2%
300	$134.18	$143.10	$8.92	6.6%
500	$211.32	$222.32	$11.00	5.2%

COMMERCIAL & INDUSTRIAL FIRM SERVICE

Use (Therms)	Bill Amount (Present)	Bill Amount (Proposed)	Increase	Percent
0	$30.00	$35.00	$5.00	16.7%
50	$54.51	$61.95	$7.43	13.6%
100	$79.02	$88.89	$9.87	12.5%
250	$152.56	$169.73	$17.17	11.3%
500	$275.12	$304.45	$29.33	10.7%
595	$321.85	$355.82	$33.97	10.6%
750	$397.68	$439.18	$41.50	10.4%
1,000	$520.24	$573.90	$53.66	10.3%
3,000	$1,500.72	$1,651.71	$150.99	10.1%
5,000	$2,481.19	$2,729.51	$248.32	10.0%
7,500	$3,706.79	$4,076.77	$369.98	10.0%
10,000	$4,932.39	$5,424.03	$491.64	10.0%

SMALL VOLUME INTERRUPTIBLE SERVICE

Use (Therms)	Bill Amount (Present)	Bill Amount (Proposed)	Increase	Percent
1,000	$450.15	$510.34	$60.19	13.4%
3,000	$1,200.45	$1,331.01	$130.56	10.9%
5,000	$1,950.76	$2,151.69	$200.93	10.3%
7,500	$2,888.64	$3,177.54	$288.90	10.0%
7,519	$2,895.63	$3,185.19	$289.56	10.0%
10,000	$3,826.51	$4,203.38	$376.87	9.8%
20,000	$7,578.03	$8,306.77	$728.74	9.6%

LARGE VOLUME INTERRUPTIBLE SERVICE

Use (Therms)	Bill Amount (Present)	Bill Amount (Proposed)	Increase	Percent
1,000	$613.35	$650.67	$37.32	6.1%
3,000	$1,290.05	$1,402.00	$111.95	8.7%
5,000	$1,966.76	$2,153.34	$186.58	9.5%
7,500	$2,812.64	$3,092.51	$279.88	10.0%
10,000	$3,658.51	$4,031.68	$373.17	10.2%
50,000	$17,192.57	$19,058.42	$1,865.84	10.9%
99,799	$34,042.29	$37,766.50	$3,724.21	10.9%
100,000	$34,110.14	$37,841.83	$3,731.69	10.9%
150,000	$51,027.72	$56,625.25	$5,597.53	11.0%
200,000	$67,945.29	$75,408.67	$7,463.38	11.0%

Peak Day Demand Costs - Total	$9,397,641
(1) Twelve Month Peak Day Demand Costs	$5,070,735
(2) Firm Demand Billing Units (therms)	97,397,900
(3) Firm Demand Cost per Therm	$0.05206
(4) Winter Peak Day Demand Costs	$4,326,906
(5) Firm Demand Billing Units (therms)	73,319,819
(6) Firm Demand Cost per Therm	$0.05901

Commodity Costs (Taken From Budget)	Class Commodity Cost	Commodity Cost per therm	Summer Total Capacity & Commodity Cost per therm	Winter Total Capacity & Commodity Cost per therm
Residential Firm	$11,397,267	$0.28715	$0.33921	$0.39823
Commercial Firm	$16,570,680	$0.28715	$0.33921	$0.39823
Small Interruptible	$1,636,515	$0.28715	$0.28715	$0.28715
Large Interruptible	$4,932,326	$0.28715	$0.28715	$0.28715
Transportation	$0			
TOTAL	$34,536,788	$0.28715		$43,934,429

Other Revenue Impact

Tariff	Type	Present Charge	Proposed Charge	Unit	Present Revenue	Proposed Revenue	Difference
5.2	Excess Footage	$3.50	$9.10	6,473	$22,656	$58,904	$36,249
5.3	Excavation	$400	$685	16	$6,400	$10,960	$4,560
5.3	Main & Service Ext.	$3.00	$8.90	2,621	$7,863	$23,327	$15,464
				Revenue Impact	**$36,919**	**$93,191**	**$56,273**

		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