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-23-___
Exhibit___(CJB-1)

Class Cost of Service Study

December 29, 2023

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Rate Consultant.

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 12 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).

Q. PLEASE SUMMARIZE NSP'S CCOSS PROPOSAL.

A. The CCOSS is done on a forecasted 2024 calendar year embedded cost basis which functionalizes, classifies, and allocates budgeted plant and expenses in the test year on cost-causation principles. The Company proposes a minor modification in the Minimum System Study to recognize the capacity of the minimum sized system as a demand component. 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 modification in the Minimum System Study, refinements to the class allocations and the rationale for the adjustments. I will also detail the customer class allocations indicated by the CCOSS and discuss the results of the CCOSS.

Q. WHAT REVENUE INCREASE DOES THE CCOSS INDICATE FOR EACH CUSTOMER CLASS?

A. The CCOSS indicates a revenue increase of 24.53 percent for Residential Firm service and 1.46 percent for Commercial and Industrial (C&I) Firm customers. The CCOSS indicates a decrease in the costs of service of 13.36 percent for Small Interruptible customers and 8.98 percent for Large Interruptible customers.

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 customer classes in a way that reflects the engineering and operating characteristics of the natural gas utility system, and hence each class's contribution to the costs of providing service. 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 will be discussed by Company witness Martha E. Hoschmiller.

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	Com Firm	Small Int	Large Int	Total
Equal Total Retail Revenue	$44,344	$45,868	$2,142	$6,098	$98,453
Present Total Retail Revenue	$35,610	$45,208	$2,472	$6,700	$89,990
Revenue Deficiency	$8,734	$661	-$330	-$602	$8,463
Deficiency %	24.53%	1.46%	-13.36%	-8.98%	9.40%

Q. PLEASE EXPLAIN THE CCOSS RESULTS.

A. The CCOSS indicates a revenue increase of 24.53 percent for Residential Firm service and 1.46 percent for Commercial and Industrial (C&I) Firm customers. The CCOSS indicates a decrease in the costs of service of 13.36 percent for Small Interruptible customers and 8.98 percent for Large Interruptible customers.

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

A. No, for several reasons. The biggest driver in this rate application is primarily associated with our gas distribution system (77 percent of our total plant in service in the test year is distribution plant) and new business is the largest category of distribution plant capital additions as Company witness Alicia E. Berger explains in her Direct Testimony. As Company witness John M. Goodenough explains in his Direct Testimony, the Company has continued to experience steady growth in customers consistent with the trend in recent years.

Additionally, in our last filed North Dakota natural gas rate case, the CCOSS indicated that Residential rates would need to increase 33.72 percent from the current rates at that time in order to pay their full cost. The Residential class received 8.75 percent, which was above the average increase of 7.54 percent in that case. While progress was made for the Residential class, rates for the Residential class were still set well below their full cost to serve. Thus, the CCOSS results shown in Table 1 above are not unexpected.

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

A. The Company is using the same primary allocators as these allocators continue to be the most appropriate class allocators for assigning costs that vary by customer count, demand (design day, i.e. demand on the coldest winter day that is reasonably possible), sales, or distribution investment. Table 2 provides a comparison of the primary allocators evaluating their current percentages versus those in the last natural gas rate case. These allocators are explained in further detail below. While there are modest changes in these allocators as compared to the prior rate case, there are not material changes to the percentages themselves. The Company is, however, proposing a demand adjustment to its Minimum System Study, which I will explain later. The impact of this adjustment is a cost shift from the Residential class to other classes. This results in a reduction in the "Mains, Overall" percentage for the Residential class and an increase in the class allocators for all other classes. I will explain later in my testimony how these allocators were developed for this CCOSS.

Table 2
Allocator Comparison (2024 TY vs. 2022 TY)

Allocator	Total	Res	C&I Firm	Sm Int	Lg Int
Customers - 2024	100.00%	84.96%	14.92%	0.08%	0.04%
Customers - 2022	100.00%	84.95%	14.91%	0.10%	0.04%
Design Day - 2024	100.00%	40.36%	59.64%	0.00%	0.00%
Design Day - 2022	100.00%	43.24%	56.76%	0.00%	0.00%
Mains, Overall - 2024	100.00%	61.36%	36.32%	0.59%	1.74%
Mains, Overall - 2022	100.00%	69.47%	27.47%	0.54%	2.52%
Meter & Regul Study - 2024	100.00%	67.67%	30.53%	0.97%	0.83%
Meter & Regul Study - 2022	100.00%	67.54%	30.46%	1.05%	0.95%
Sales, W/o Transp - 2024	100.00%	33.82%	50.67%	3.93%	11.58%
Sales, W/o Transp - 2022	100.00%	33.00%	47.98%	4.74%	14.28%
Sales, W/ Transp - 2024	100.00%	29.89%	55.73%	3.47%	10.91%
Sales, W/ Transp - 2022	100.00%	28.29%	46.30%	4.06%	21.34%
Service Study - 2024	100.00%	70.05%	29.28%	0.67%	0.00%
Service Study - 2022	100.00%	68.96%	30.53%	0.51%	0.00%

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 Benjamin C. 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. 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 based on the number of customers and not by variations in gas usage or contribution to overall demand on a Design Day. 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-21-381). Except for the inclusion of the demand adjustment in the Minimum System Study, the allocation factors used in our previous rate case were used in this CCOSS. The various allocation percentages have been updated to reflect forecasted 2024 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 3 below shows the amount of distribution plant by category and how they are classified:

Table 3
Distribution Plant by Category

Distribution Plant Category	2024 TY Plant in Service (000)	Demand Component	Customer Component
Distribution Mains	$129,802	X	X
Services	$67,913		X
Meters & Regulators	$16,318		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 one modification – a demand adjustment to the Minimum System Study. The Minimum System Study is provided in Exhibit___(CJB-1), Schedule 4. However, as I noted above, the Company is proposing to apply a demand adjustment to the Minimum System Study results.

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 65.3 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 DEMAND ADJUSTMENT BEING APPLIED IN THE MINIMUM SYSTEM STUDY.

A. The Minimum System Study identifies distribution mains of two inches or less as its theoretical minimum system. The ratio of the cost of this Minimum System compared to the total cost of distribution mains is used to determine the customer-related costs associated with distribution mains. However, distribution mains of two inches or less have some capacity and there is a difference in the extent to which that portion of the pipeline capacity is used by different customer classes. The Company is proposing to apply a demand adjustment that accounts for the carrying capacity of two-inch mains. Company engineers calculated the capacity of a two-inch pipe, and I utilized this capacity to calculate a demand adjustment in the Minimum System Study. Table 4 illustrates how the demand adjustment was calculated.

Table 4
Demand Adjustment Calculation

Class	Demand (Dth)	Customers	Demand Adjustment (Dth/Day/Customer)	Minimum (Dth)
Residential	51,053	54,948	0.315	17,309
Commercial Firm	75,438	9,648	0.315	3,039
Total	126,491	64,596		20,348
20,348 Dth / 126,491 Dth = 16.1%				

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

A. Average Capacity costs are determined by taking the remaining 50.8 percent of the total cost of mains and multiplying by the test year 2024 system load factor. The system load factor is the percentage of Dekatherms actually delivered annually system-wide as compared to the total possible Dekatherms that could be delivered annually system-wide. The total possible Dekatherms that could be delivered annually system-wide is calculated by multiplying the peak Design Day demand by 365 days. The annual system-wide sales is then divided by that total possible deliveries. Here, the Minimum System Study calculated the total possible annual deliveries as 46,169,215 Dth, which is the Company's peak demand (2023-2024 Design Day Demand of 126,491 Dth – which is the most recent data available when performing the study) multiplied by 365. The Company's 2024 test year sales forecast of 14,337,878 Dth divided by the total possible annual deliveries as 46,169,216 Dth yields a forecasted system load factor of 31.1 percent for the 2024 test year. Multiplying the 50.8 percent of the remaining total cost of mains by the system load factor of 31.1 leads to an Average Capacity of 15.8 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 35.0 percent of total cost of mains not ascribed to the Minimum System and Average Capacity components. The Excess Capacity costs are allocated to the specific classes 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, 14.52, and 28.07, 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. This is the same approach that was used by the Company in the last rate case.

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 2.38, 6.86, and 6.33, respectively.

I then calculated the allocator for gas services by applying the weightings of each class by the number of customers in each class. This is the same approach that was used by the Company in the last rate case.

B. Other Cost Studies within CCOSS

Q. WHAT OTHER COST STUDIES DID YOU PERFORM?

A. I performed Customer Care, Uncollectibles, and Late Payment studies using the same approach that was used by the Company in the last rate case.

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. 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.

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.

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 2023-2024 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 the sales with transportation allocators. Using the Company's 2024 test year sales forecast as sponsored by Company witness Goodenough, 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.

V. 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 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 ratemaking tool in this case and was used to inform a moderated class revenue apportionment.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

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

Rate Consultant; Xcel Energy, NSPM	2022 – Present
Principal Pricing Analyst; Xcel Energy, NSPM	2017 – 2022
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's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four main functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function	Description
Production	304, 305, 311, 108(1), 190, 281-283 Net, 710, 733, 735, 736, 742, 759, 840-843, 403, 408.1, 410.1, 411.1, 420	None	Includes 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 three principle service requirements or billing components are:

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

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

The table below shows how each of the functional and sub-functional costs 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	**65.3%**	**34.7%**

The Minimum Distribution System method 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 65.3 percent of actual investment. These Minimum System costs are allocated to class based on number of customers in each class and are also assigned to the Customer Charge billing component. However, it is reasonable to make a demand adjustment that accounts for capacity associated with the two-inch pipe that makes up the Minimum System. The Company calculated a demand adjustment of 16.1 percent. The following table illustrates the adjusted customer- and demand-related classification of distribution main costs.

Cost	**Customer**	**Demand**
Distribution Costs	**49.2%**	**50.8%**

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

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

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. An example of a directly assigned cost is purchased gas expenses.
- 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 two types of allocators:
        - External Allocators –These are allocators that are based on data from outside the CCOSS model (e.g. design day demands, metering and customer service-related cost ratios). In general, there are three types of external allocators:
            - Capacity –related (sometimes referred to as Demand) allocators such as:
                - Design Day Demands – each firm class's usage in extreme peaking conditions
                - Excess Design Day – the portion of design day demand in excess of average daily sales
            - Commodity-related allocators such as:
                - Sales W/Transp – Forecasted sales, including forecasted transportation
                - Sales W/o Transp – Forecasted sales without forecasted transportation
            - Customer-related allocators
                - Number of customers
                - Weighted number of customers, where the weights are based on cost of meters, services, billing, etc.

            Details on the external allocators used in the CCOSS model are shown in Exhibit___(CJB-1), Schedule 3, Page 11.

        - 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 10.

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

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

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

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

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

Name	Derivation	E/I	Components
Mod Rate Base (Component only)	Column version of Rate Base excluding Working Cash	Int	CDE-BSP
Modified O&M Expense	Total O&M expense, less rate case expense and various Admin & General expenses	Int	CDE-BSP
Net Plant	Plant In Service, minus Accumulated Depreciation	Int	CD -BSP
Other Production Expense	Miscellaneous production expenses for LPG, LNG, etc.	Int	DE- P
Present Retail Rev (Class only)	Forecasted present revenue	Ext	---
Prod-Stor-Tran-Dis	Total Production, Storage, Transmission and Distribution, from original plant investment	Int	CD -BSP
Rate Base	Rate Base (Plant in Svc, less Accumulated Deprec, plus and minus other adjustments)	Int	CDE-BSP
Record & Coll Study	Forecasted customers, weighted by typical cost to provide billing records and collections	Ext	C -
Rt Base, w/o Work Cash	Rate base, excluding working cash	Int	CDE-BSP
Sales, W/ Transp	Forecasted sales, including forecasted transportation	Ext	E-
Sales, W/o CIP Exempt	Forecasted sales, w/o forecasted CIP-exempt sales	Ext	E-
Sales, W/o Transp	Forecasted sales, w/o forecasted transportation	Ext	E-
Service Study	Customer count, weighted by relative cost of each class' 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

Allocator	Category	Item	Page	Line
		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	9	30
		Cust Serv & Inform	9	31
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	9	29
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	9	36
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	9	32
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	9	34
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 $8,733,994 and the cost-based customer charge for residential of $25.30 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 2024

SUMMARY

Rate Base

		ND	Res	C&I	Sm Int	Lg Int
1	Production	11,445	4,619	6,825	0	0
2	Storage	14,311	5,776	8,535	0	0
3	Transmission	4,006	1,541	2,286	43	136
4	Distribution	214,184	138,313	72,095	1,247	2,530
5	General	35,889	22,104	13,203	190	392
6	Common	0	0	0	0	0
7	**Total Plant In Service**	**279,835**	**172,354**	**102,944**	**1,480**	**3,058**
8	Production	2,944	1,188	1,756	0	0
9	Storage	8,376	3,380	4,995	0	0
10	Transmission	1,823	701	1,040	20	62
11	Distribution	66,906	44,102	21,782	386	636
12	General	15,955	9,827	5,869	84	174
13	Common	0	0	0	0	0
14	**Total Depreciation Reserve**	**96,003**	**59,199**	**35,442**	**490**	**872**
15	**Net Plant**	**183,832**	**113,156**	**67,501**	**989**	**2,186**
16	**Deductions** (Accum Def Inc Tax)	**22,872**	**14,921**	**7,591**	**136**	**224**
17	**Additions**	**7,011**	**2,532**	**3,661**	**197**	**621**
18	**Rate Base**	**167,970**	**100,766**	**63,572**	**1,050**	**2,582**

Income Statement

		ND	Res	C&I	Sm Int	Lg Int
19	**Present Retail Revenue**	**89,990**	**35,610**	**45,208**	**2,472**	**6,700**
20	**Present Other Oper Rev**	**469**	**338**	**131**	**1**	**0**
21	**Present Total Operating Rev**	**90,459**	**35,948**	**45,338**	**2,473**	**6,700**
	Operating & Maint Expenses					
22	Purchased Gas Expense	58,155	20,516	30,498	1,808	5,333
23	Other Purch Gas Exp	0	0	0	0	0
24	Other Production	2,300	829	1,253	55	164
25	Transmission	295	114	169	3	10
26	Distribution	5,282	3,505	1,673	29	75
27	Customer Accounting	1,354	1,084	218	36	16
28	Customer Service and Information	126	97	21	6	1
29	Administrative and General	3,474	2,066	1,270	37	100
30	Amortizations; Sales Expense	602	385	198	5	14
31	**Total Operating & Maint Exp**	**71,587**	**28,595**	**35,301**	**1,979**	**5,711**
32	Book Depreciation	9,370	5,692	3,543	46	89
33	Taxes Other Than Income Taxes	2,415	1,041	1,285	22	68
34	Prov For Deferred Inc Taxes	1,277	779	479	6	13
35	Net Investment Tax Credit	0	0	0	0	0
36	**Total Operating Expense**	**84,649**	**36,107**	**40,608**	**2,054**	**5,880**
37	State and Federal Income Taxes	-423	-1,235	518	101	192
38	**Total Expense**	**84,226**	**34,872**	**41,125**	**2,155**	**6,073**
39	AFUDC (Rev Credit)	0	0	0	0	0
40	**Total Operating Income**	**6,234**	**1,075**	**4,213**	**318**	**628**
41	**Rate Base**	**167,970**	**100,766**	**63,572**	**1,050**	**2,582**
42	**Present Return on Rate Base**	**3.71%**	**1.07%**	**6.63%**	**30.28%**	**24.32%**
43	**Present Return on Common Equity**	**2.95%**	**-2.08%**	**8.51%**	**53.56%**	**42.20%**
44	**Required Return on Rate Base**	**7.52%**	**7.52%**	**7.52%**	**7.52%**	**7.52%**
45	**Required Operating Income**	**12,631**	**7,578**	**4,781**	**79**	**194**
46	**Income Deficiency**	**6,398**	**6,502**	**568**	**-239**	**-434**
47	**Revenue Deficiency**	**8,463**	**8,734**	**661**	**-330**	**-602**
48	**Deficiency / Pres Retail Revenue**	**9.40%**	**24.53%**	**1.46%**	**-13.36%**	**-8.98%**

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024 | SUMMARY | Page 2 of 12

Equal Return vs Present

	Operating Revenue Requirement	ND	Res	C&I	Sm Int	Lg Int
1	Return On Rate Base	7.52%	7.52%	7.52%	7.52%	7.52%
2	Equalized Total Retail Rev	98,453	44,344	45,868	2,142	6,098
3	Present Total Retail Revenue	89,990	35,610	45,208	2,472	6,700
4	Revenue Deficiency	8,463	8,734	661	-330	-602
5	Deficiency / Pres Total Retail Rev	9.40%	24.53%	1.46%	-13.36%	-8.98%
	Internal Retail Revenue Reqt					
6	Customer Retail Revenue Requirement	21,352	16,680	4,519	104	50
7	Average Monthly Customers	64,674	54,948	9,648	54	24
8	Revenue Requirement $ / Mo / Cust	27.51	25.30	39.03	159.01	174.62
9	Capacity Retail Revenue Requirement	16,140	6,255	9,360	127	399
10	Annual Dkt Sales	14,337,878	4,285,129	7,990,310	497,468	1,564,971
11	Revenue Requirement $ / Dkt	1.13	1.46	1.17	0.25	0.26
	Capacity - Sub Classification					
12	Capacity - Base Revenue Requirement	3,546	1,048	1,972	127	399
13	Capacity - Seasonal Revenue Requirement	7,827	3,296	4,531	0	0
14	Peak Shaving Revenue Requirement	4,767	1,910	2,857	0	0
15	Base Rev Requirement $ / Dkt	0.25	0.24	0.25	0.25	0.26
16	Seasonal Rev Requirement $ / Dkt	0.55	0.77	0.57	0.00	0.00
17	Peak Shave Rev Requirement $ / Dkt	0.33	0.45	0.36	0.00	0.00
18	Energy Retail Revenue Requirement	2,789	879	1,490	104	316
19	Revenue Requirement $ / Dkt	0.19	0.21	0.19	0.21	0.20
20	Total Internal Retail Revenue Requirement	40,281	23,813	15,369	334	766
21	Revenue Requirement $ / Dkt	2.81	5.56	1.92	0.67	0.49
22	Revenue Requirement $ / Mo / Cust	51.90	36.11	132.75	512.95	2,658.98
	External Retail Revenue Reqt					
23	Capacity Revenue Requirement	12,118	4,945	7,173	0	0
24	Energy Revenue Requirement	46,037	15,571	23,325	1,808	5,333
25	Total External Revenue Requirement	58,155	20,516	30,498	1,808	5,333
26	Cap Revenue Requirement $ / Dkt	0.85	1.15	0.90	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	3.21	3.63	2.92	3.63	3.41
28	Tot Revenue Requirement $ / Dkt	4.06	4.79	3.82	3.63	3.41
	Total Retail Revenue Reqt					
29	Customer Revenue Requirement	21,352	16,680	4,519	104	50
30	Capacity Revenue Requirement	28,258	11,199	16,533	127	399
31	Energy Revenue Requirement	48,826	16,450	24,815	1,912	5,649
32	Total Revenue Requirement	98,436	44,329	45,867	2,142	6,098
33	Customer Revenue Reqt $ / Dkt	1.49	3.89	0.57	0.21	0.03
34	Demand Revenue Reqt $ / Dkt	1.97	2.61	2.07	0.25	0.26
35	Energy Revenue Reqt $ / Dkt	3.41	3.84	3.11	3.84	3.61
36	Total Revenue Reqt $ / Dkt	6.87	10.34	5.74	4.31	3.90

Proposed Return vs Present

		ND	Res	C&I	Sm Int	Lg Int
37	Proposed Total Retail Revenue	98,453	40,076	48,472	2,662	7,242
38	Revenue Deficiency	8,463	4,466	3,265	190	542
39	Deficiency / Pres Total Oper Revenue	9.40%	12.54%	7.22%	7.67%	8.09%

Proposed Return vs Equal

		ND	Res	C&I	Sm Int	Lg Int
40	Revenue Difference	0	-4,268	2,604	520	1,144
41	Difference / Tot Equal Revenue"	0.00%	-9.62%	5.68%	24.27%	18.76%

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

Case No. PU-23-___
Exhibit___(CJB-1), Schedule 3
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RATE BASE

	Plant in Service	FERC Accounts	Allocator		ND	Res	C&I	Sm Int	Lg Int
1	**Production Plant (LPG)**	304, 305, 311	Design Day		11,445	4,619	6,825	0	0
2	**Storage Plant (LNG)**	360, 361, 362, 363	Design Day		14,311	5,776	8,535	0	0
3	**Transmission Plant**	365, 366, 367, 368, 369, 370, 371	Average and Peak		4,006	1,541	2,286	43	136
	Distribution Plant								
4	Regulator Stations	374, 375, 378, 379	Average and Peak		151	58	86	2	5
5	Mains - Minimum System	376	Customers	49.2%	63,898	54,288	9,532	54	24
6	Mains - Average Capacity	Split of 376	Sales, W/ Transp	15.8%	20,467	6,117	11,406	710	2,234
7	Mains - Excess Capacity	Split of 376	Excess Design Day	35.0%	45,438	19,237	26,201	0	0
8	Mains - Total	376			129,802	79,642	47,139	764	2,258
9	Services	380	Service Study		67,913	47,572	19,888	323	131
10	Meters	381	Meter & Regul Study		12,866	8,706	3,928	125	107
11	House Regulators	383	Meter & Regul Study		3,451	2,335	1,054	34	29
12	Total Distribution Plant	Subtotal			214,184	138,313	72,095	1,247	2,530
13	**General Plant**	390-399	Prod-Stor-Tran-Dis		35,889	22,104	13,203	190	392
14	**Common Plant**	390-399	Prod-Stor-Tran-Dis		0	0	0	0	0
15	**Gas Plant in Service**	Total			**279,835**	**172,354**	**102,944**	**1,480**	**3,058**
	Accum Depr Reserve	**FERC Accounts**							
16	**Production Plant (LPG)**	108(1)	Design Day		2,944	1,188	1,756	0	0
17	**Storage Plant (LNG)**	108(5)	Design Day		8,376	3,380	4,995	0	0
18	**Transmission Plant**	108(7)	Average and Peak		1,823	701	1,040	20	62
	Distribution Plant								
19	Regulator Stations	108(8)	Average and Peak		0	0	0	0	0
20	Mains	108(8)	Mains, Overall		29,905	18,348	10,860	176	520
21	Services	108(8)	Service Study		30,064	21,059	8,804	143	58
22	Meters	108(8)	Meter & Regul Study		6,047	4,092	1,846	59	50
23	House Regulators	108(8)	Meter & Regul Study		891	603	272	9	7
24	Total Distribution Plant	Sub-total			66,906	44,102	21,782	386	636
25	**General Plant**	108(9)	Prod-Stor-Tran-Dis		15,955	9,827	5,869	84	174
26	**Common Plant**	108(9)	Prod-Stor-Tran-Dis		0	0	0	0	0
27	**Total Accum Depr**	Sub-total			**96,003**	**59,199**	**35,442**	**490**	**872**
28	**Net Plant**	Total			**183,832**	**113,156**	**67,501**	**989**	**2,186**
	Subtractions to Net Plant								
	Accum Deferred Inc Tax	**FERC Accounts**							
29	**Production Plant (LPG)**	190, 281, 282, 283 Net	Design Day		-17	-7	-10	0	0
30	**Storage Plant (LNG)**	190, 281, 282, 283 Net	Design Day		-117	-47	-70	0	0
31	**Transmission Plant**	190, 281, 282, 283 Net	Average and Peak		618	238	353	7	21
	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		7,528	4,619	2,734	44	131
34	Services	190, 281, 282, 283 Net	Service Study		9,487	6,646	2,778	45	18
35	Meters	190, 281, 282, 283 Net	Meter & Regul Study		2,306	1,561	704	22	19
36	House Regulators	190, 281, 282, 283 Net	Meter & Regul Study		254	172	78	2	2
37	Total Distribution Plant	Sub-total			19,576	12,997	6,294	114	171
38	**General Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis		2,594	1,598	954	14	28
39	**Common Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis		0	0	0	0	0
40	Accumulated Deferred Tax	283	Net Plant		0	0	0	0	0
41	Non-Plant Related	190 & 282 Net	Labor		217	142	69	2	4
42	**Total Subtractions**	Total			**22,872**	**14,921**	**7,591**	**136**	**224**

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

Additions to Net Plant

	CWIP	FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
1	Production Plant (LPG)		Design Day	127	51	76	0	0
2	Storage Plant (LNG)		Design Day	263	106	157	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	83	51	30	0	1
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	205	126	75	1	2
10	Total CWIP	Sub-total		678	335	338	2	4
11	**Materials & Supplies**	154, 155, 156	Tran & Distrib	306	196	104	2	4
	Gas In Storage							
12	Total Gas in Storage	Total	Sales, W/ Transp	6,008	1,796	3,348	208	656
13	**Non-Plant Assets & Liab**	Total	Labor	1,049	688	334	7	20
	Miscellaneous	**FERC Accounts**						
14	Prepay: Insurance	165	Tran & Distrib	0	0	0	0	0
15	Prepay: Miscellaneous	165	Tran & Distrib	-304	-195	-104	-2	-4
16	Fuel	176	Sales, W/o Transp	0	0	0	0	0
17	Total Miscellaneous			-304	-195	-104	-2	-4
	Working Cash							
30	Total Working Cash	Total	Modified O&M Expense	-726	-287	-360	-20	-59
31	**Total Additions**	Sub-total		**7,011**	**2,532**	**3,661**	**197**	**621**
32	**Total Rate Base**	Sub-Total		**167,970**	**100,766**	**63,572**	**1,050**	**2,582**
33	**Common Rate Base (@ 52.50%)**			**88,184**	**52,902**	**33,375**	**551**	**1,356**
34	Customer Component			91,802	71,646	19,728	278	149
35	Demand Component			70,567	27,463	40,700	580	1,824
36	Energy Component			5,601	1,657	3,143	192	608

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

Operating Revenue (Cal Month)

			Allocator	ND	Res	C&I	Sm Int	Lg Int
	Retail Revenue							
1a	**Present Retail Rev**	480, 481, 482, 484	Direct Assign	**89,990**	**35,610**	**45,208**	**2,472**	**6,700**
1b	**Proposed Retail Rev**		Direct Assign	**98,436**	**40,061**	**48,471**	**2,662**	**7,242**
2	**Retail Rev Increase**			**8,446**	**4,451**	**3,263**	**190**	**542**
	Other Operating Revenue							
3	Late Pay Penalties	488, 495	Late Pay; Mod Pres Rev	181	163	17	1	0
4	Connection Charges	488, 495	Customers	120	102	18	0	0
5	Return Check Charges	488, 495	Customers	7	6	1	0	0
6	Connect Smart	488, 495	Customers	4	3	1	0	0
7	Interchange Gas	488, 495	Design Day	66	27	39	0	0
8	Other Gas Revenue	488, 495	Design Day	65	26	39	0	0
9	Ltd Firm Sales - Rsrvs & Vols	488, 495	Design Day	27	11	16	0	0
10	Other Gas Revenue - Distr	488, 495	Design Day	3	1	2	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	-3	-1	-2	0	0
13	**Tot Other Oper Rev - Pres**	**Sub-total**		**469**	**338**	**131**	**1**	**0**
14	Incr Misc Serv		Customers	0	0	0	0	0
15	Incr Late Pay - Proposed		Late Pay; Mod Pres Rev	17	15	2	0	0
16	**Tot Other Oper Rev - Prop**			**486**	**353**	**132**	**1**	**0**
16a	**Total Oper Rev - Present**	Total		**90,459**	**35,948**	**45,338**	**2,473**	**6,700**
16b	**Total Oper Rev - Proposed**			**98,922**	**40,414**	**48,603**	**2,663**	**7,243**
17	**Operating Rev Increase**			**8,463**	**4,466**	**3,265**	**190**	**542**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	**FERC Accounts**	**Alloc**	ND	Res	C&I	Sm Int	Lg Int
18	Commodity	728, 804, 805, 808, 858	Direct Assign	46,037	15,571	23,325	1,808	5,333
19	Demand	804, 808, 858	Direct Assign	12,118	4,945	7,173	0	0
20	Propane		Design Day	0	0	0	0	0
21	Limited Firm	728	Design Day	0	0	0	0	0
22	Total Purchases	Sub-total		58,155	20,516	30,498	1,808	5,333
	Other Production Expense							
23	Other Purchased Gas		Design Day	186	75	111	0	0
24	Misc. LPG Op Exp	710, 733, 735, 736, 742, 759	Design Day	520	210	310	0	0
25	MGP	735	Sales, W/o Transp	1,250	423	633	49	145
26	Misc. LNG Op Exp	840, 841, 842, 843	1/2 Dsgn Day, 1/2 Ener	344	121	198	6	19
27	Total Other Production Expense			2,300	829	1,253	55	164
28	**Transmission Expense**	850-865	Average and Peak	295	114	169	3	10
	Distribution Expense							
29	Regulator Stations	875, 877, 889, 891	Average and Peak	111	43	64	1	4
30	Mains	874, 887	Mains, Overall	2,072	1,271	753	12	36
31	Services	892	Service Study	509	357	149	2	1
32	Meters	878, 893	Meter & Regul Study	-750	-508	-229	-7	-6
33	House Regulators	878, 893	Meter & Regul Study	861	583	263	8	7
34	Other Property & Equipment	881	Customers	167	142	25	0	0
35	Dispatching	871	1/2 Dsgn Day, 1/2 Ener	380	133	219	7	21
36	Customer Installations	879	Customers	313	266	47	0	0
37	Other Distribution	880	Customers	774	657	115	1	0
38	Supervision & Engineering	870, 885	Dist Exp, w/o Sup & Eng	844	560	267	5	12
39	Total Distribution Expense	Sub-total		5,282	3,505	1,673	29	75

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

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	4	1	0	0
2	Acct Meter Read	902	Customers	136	115	20	0	0
3	Acct Recrds & Coll	903	Record & Coll Study	760	588	121	36	16
4	Acct Uncollect	904	Uncollectibles Study	444	368	75	0	0
5	Acct Misc	905	Customers	10	9	2	0	0
6	Asst Expense (w/o CIP)	908	Cust Inform Study	126	97	21	6	1
7	Serv Instruct Adver	909	Customers	0	0	0	0	0
8	Tot Cust Acctg & Inform			1,480	1,181	240	42	17
	Admin & General							
9	Property Insurance	924	Net Plant	99	61	36	1	1
10	Pension & Benefit-Direct	926	Labor	1,002	657	319	7	19
11	Salaries	920	Labor	976	640	311	7	18
12	Office & Supplies	921	Labor	643	421	204	4	12
13	Admin Transfer Credit	922	Labor	-745	-488	-237	-5	-14
14	Outside Services	923	Labor	206	135	66	1	4
15	Incentive Compensation	920 + other	Labor	0	0	0	0	0
16	Injuries and Claims	925	1/2 Rt Base, 1/2 Pres Rev;	227	113	100	4	10
17	Regulatory Comm Exp	928	Present Retail Revenue	35	14	18	1	3
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;	5	3	2	0	0
20	Misc General Exp	930	1/2 Rt Base, 1/2 Pres Rev;	36	18	16	1	2
21	Rents	931	1/2 Rt Base, 1/2 Pres Rev;	982	489	433	17	44
22	Maint of Gen Plt	935	1/2 Rt Base, 1/2 Pres Rev;	8	4	4	0	0
23	Total A & G Expense			3,474	2,066	1,270	37	100
	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	25	10	13	1	2
27	Total Customer Service Info	Sub-total		25	10	13	1	2
28	Amortizations		Labor	567	372	180	4	11
	Sales Expense							
29	Sales, Econ Dvlp & Other	912	Sales, W/ Transp	9	3	5	0	1
30	Total Sales Expense	Sub-total		9	3	5	0	1
31	**Total O&M Expense**			**71,587**	**28,595**	**35,301**	**1,979**	**5,711**

Book Depreciation

		FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
32	**Production Plant (LPG)**	403	Design Day	732	295	436	0	0
33	**Storage Plant (LNG)**	403	Design Day	525	212	313	0	0
34	**Transmission Plant**	403	Average and Peak	79	30	45	1	3
	Distribution Plant							
35	Regulator Stations	403	Average and Peak	0	0	0	0	0
36	Mains	403	Mains, Overall	2,920	1,791	1,060	17	51
37	Services	403	Service Study	2,142	1,500	627	10	4
38	Meters	403	Meter & Regul Study	430	291	131	4	4
39	House Regulators	403	Meter & Regul Study	92	62	28	1	1
40	Total Distribution Plant			5,583	3,645	1,847	32	59
41	**General Plant**	403	Prod-Stor-Tran-Dis	2,450	1,509	901	13	27
42	**Common Plant**	403, 404	Prod-Stor-Tran-Dis	0	0	0	0	0
43	**Total Book Deprec**	Sub-total		**9,370**	**5,692**	**3,543**	**46**	**89**

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

INCOME STATEMENT

	Real Estate & Prop Taxes	FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
1	**Production Plant (LPG)**	408	Design Day	246	99	147	0	0
2	**Storage Plant (LNG)**	408	Design Day	0	0	0	0	0
3	**Transmission Plant**	408	Average and Peak	32	12	18	0	1
	Distribution Plant							
4	Regulator Stations	408	Average and Peak	1,741	670	994	19	59
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		1,741	670	994	19	59
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		**2,020**	**782**	**1,159**	**19**	**60**
13	Payroll Taxes	408	Labor	396	259	126	3	7
14	**Tot Non-Income Taxes**			**2,415**	**1,041**	**1,285**	**22**	**68**
	Provision-Defer Inc Tax	**FERC Accounts**						
15	**Production Plant (LPG)**	410.1, 411.1	Design Day	36	14	21	0	0
16	**Storage Plant (LNG)**	410.1, 411.1	Design Day	114	46	68	0	0
17	**Transmission Plant**	410.1, 411.1	Average and Peak	-10	-4	-6	0	0
	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	415	255	151	2	7
20	Services	410.1, 411.1	Service Study	225	158	66	1	0
21	Meters	410.1, 411.1	Meter & Regul Study	55	37	17	1	0
22	House Regulators	410.1, 411.1	Meter & Regul Study	16	11	5	0	0
23	Total Distribution Plant	Sub-total		711	460	238	4	8
24	**General Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	433	267	159	2	5
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	-7	-5	-2	0	0
28	**Tot Prov Defer Inc Tax**	Total		**1,277**	**779**	**479**	**6**	**13**
	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		**84,649**	**36,107**	**40,608**	**2,054**	**5,880**
42a	**Pres Op Inc Before Inc Tax**	Total		**5,811**	**-159**	**4,730**	**420**	**820**
42b	**Prop Op Inc Before Inc Tax**	Total		**14,274**	**4,307**	**7,995**	**609**	**1,362**

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

INCOME STATEMENT

	Tax Deprec & Removal	FERC Accounts	Allocator	ND	Res	C&I	Sm Int	Lg Int
1	**Production Plant (LPG)**	Not Applicable	Design Day	911	368	543	0	0
2	**Storage Plant (LNG)**	Not Applicable	Design Day	938	379	559	0	0
3	**Transmission Plant**	Not Applicable	Average and Peak	59	23	33	1	2
	Distribution Plant							
4	Regulator Stations	Not Applicable	Average and Peak	0	0	0	0	0
5	Mains	Not Applicable	Mains, Overall	5,322	3,265	1,933	31	93
6	Services	Not Applicable	Service Study	2,601	1,822	762	12	5
7	Meters	Not Applicable	Meter & Regul Study	569	385	174	6	5
8	House Regulators	Not Applicable	Meter & Regul Study	117	79	36	1	1
9	Total Distribution Plant	Sub-total		8,610	5,552	2,904	50	103
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	4,502	2,771	1,653	24	54
13	**Total Tax Depreciation**	Total		**15,020**	**9,092**	**5,693**	**75**	**159**
	Present Return							
	Inc Tax Additions	**FERC Accounts**						
14	Total Book Depr Exp	from another page		9,370	5,692	3,543	46	89
15	Provision for Deferred	from another page		1,276.78	779	479	6	13
16	Net Inv Tax Credit	from another page		0	0	0	0	0
17	Avoided Tax Interest	Not Applicable	CWIP	235	116	117	1	1
18	Total Tax Additions	Sub-total		10,881	6,586	4,139	53	102
	Inc Tax Deductions							
19	Tax Depr & Removal Exp	from another page		15,020	9,092	5,693	75	159
20	Debt Interest Expense	Calculation	; Mod Rate Base	3,628	2,177	1,373	23	56
21	Other Timing Differences	Not Applicable	Labor	-396	-260	-126	-3	-7
22	Meals		Labor	14	9	4	0	0
23	Total Tax Deductions			18,265	11,018	6,945	95	207
23a	**Pres Taxable Net Income**	Calculation		**-1,574**	**-4,591**	**1,924**	**377**	**715**
23b	**Prop Taxable Net Income**			**6,889**	**-125**	**5,189**	**567**	**1,258**
24	Pres State Tax Before Credits			-68	-198	83	16	31
25	Prop State Tax Before Credits			297	-5	224	24	54
26	Equal State Tax Before Credits			297	179	111	2	5
27	Pres State Tax Credits			8	23	-10	-2	-4
28	Prop State Tax Credits			8	0	6	1	1
29	Equal State Tax Credits			8	5	3	0	0
30	Pres State Tax After Credits			-75.84	-221	93	18	34
31	Prop State Tax After Credits			289	-5	218	24	53
32	Equal State Tax After Credits			289	174	108	2	5

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024 | Page 9 of 12

INCOME STATEMENT

1	Pres Federal Taxable Income			-1,498	-4,369	1,832	359	681
2	Prop Federal Taxable Income			6,600	-119	4,972	543	1,205
3	Equal Federal Taxable Income			6,600	3,970	2,477	45	109
4	Pres Federal Tax Before Credits			-315	-918	385	75	143
5	Prop Federal Tax Before Credits			1,386	-25	1,044	114	253
6	Equal Federal Tax Before Credits			1,386	834	520	9	23
7	Pres Federal Tax Credits			33	96	-40	-8	-15
8	Prop Federal Tax Credits			33	-1	25	3	6
9	Equal Federal Tax Credits			33	20	12	0	1
10	Pres Federal Tax After Credits			-347.34	-1,013	425	83	158
11	Prop Federal Tax After Credits			1,353	-24	1,019	111	247
12	Equal Federal Tax After Credits			1,353	814	508	9	22
13a	**Pres Inc Tax, @26.89%**	Calculation		**-423.19**	**-1,235**	**518**	**101**	**192**
13b	**Prop Inc Tax, @23.84%**			**1,642**	**-30**	**1,237**	**135**	**300**
14a	**Pres Preliminary Return**			6,234	1,075	4,213	318	628
14b	**Prop Preliminary Return**			12,631	4,336	6,758	474	1,063
15	**Total AFUDC**	Not Applicable	CWIP	**0**	**0**	**0**	**0**	**0**
16a	**Pres Total Return**	Total	; Mod Rate Base	**6,234**	**1,075**	**4,213**	**318**	**628**
16b	**Prop Total Return**		; Mod Rate Base	**12,631**	**4,336**	**6,758**	**474**	**1,063**
17a	**Pres % Return on Rate Base**	Calculation		**3.71%**	**1.07%**	**6.63%**	**30.28%**	**24.32%**
17b	**Prop % Return on Rate Base**			**7.52%**	**4.30%**	**10.63%**	**45.13%**	**41.15%**
18a	**Pres Common Return**			**2,606**	**(1,101)**	**2,840**	**295**	**572**
18b	**Prop Common Return**			**9,003**	**2,160**	**5,385**	**451**	**1,007**
19a	**Pres % Ret on Common Rt Bs**			**2.95%**	**-2.08%**	**8.51%**	**53.56%**	**42.20%**
19b	**Prop % Ret on Common Rt Bs**			**10.21%**	**4.08%**	**16.14%**	**81.85%**	**74.27%**

AFUDC

20	Production Plant (LPG)	Design Day	0	0	0	0	0
21	Storage Plant (LNG)	Design Day	0	0	0	0	0
22	Transmission Plant	Average and Peak	0	0	0	0	0
	Distribution:						
23	Regulator Stations	Average and Peak	0	0	0	0	0
24	Mains	Mains Overall	0	0	0	0	0
25	Services	Service Study	0	0	0	0	0
26	Meters	Meter & Regul Study	0	0	0	0	0
27	House Regulators	Meter & Regul Study	0	0	0	0	0
	Total Distribution		0	0	0	0	0
28	General & Common Plant	Prod-Stor-Tran-Dis	0	0	0	0	0
29	Total AFUDC		0	0	0	0	0

Labor Allocator

		FERC Accounts						
30	Customer Accounting	Labor Portion of O&M Accounts	Customers	855	726	128	1	0
31	Cust Serv & Inform	Labor Portion of O&M Accounts	Customers	19	16	3	0	0
32	Distribution	Labor Portion of O&M Accounts	Dist Exp, w/o Sup & Eng	3,010	1,998	953	17	43
33	Admin & General	Labor Portion of O&M Accounts	Labor w/o A&G	1,906	1,250	607	13	36
34	Production	Labor Portion of O&M Accounts	Other Production Exp	603	217	328	14	43
35	Sales	Labor Portion of O&M Accounts	Sales, W/ Transp	0	0	0	0	0
36	Transmission	Labor Portion of O&M Accounts	Design Day	57	23	34	0	0
37	Total			6,451	4,231	2,053	45	122

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

ALLOCATORS

	Internal Allocators	ND	Res	C&I	Sm Int	Lg Int
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**35.12%**	**57.68%**	**1.73%**	**5.46%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**49.78%**	**44.04%**	**1.69%**	**4.49%**
3	Average and Peak (Mains)	65,905	25,353	37,607	710	2,234
4	Average and Peak	**100.00%**	**38.47%**	**57.06%**	**1.08%**	**3.39%**
5	CWIP	**100.00%**	**49.37%**	**49.86%**	**0.23%**	**0.54%**
6	Dist Exp, w/o Sup & Eng	4,437	2,945	1,405	25	63
7	Dist Exp, w/o Sup & Eng	**100.00%**	**66.36%**	**31.67%**	**0.55%**	**1.42%**
8	Distribution Plant	**100.00%**	**64.58%**	**33.66%**	**0.58%**	**1.18%**
9	Gas Plant In Service	**100.00%**	**61.59%**	**36.79%**	**0.53%**	**1.09%**
10	Labor	**100.00%**	**65.58%**	**31.83%**	**0.70%**	**1.89%**
11	Mains, Overall	**100.00%**	**61.36%**	**36.32%**	**0.59%**	**1.74%**
12	Modified O&M Expense	69,702	27,574	34,536	1,952	5,640
13	Modified O&M Expense	**100.00%**	**39.56%**	**49.55%**	**2.80%**	**8.09%**
14	Net Plant	**100.00%**	**61.55%**	**36.72%**	**0.54%**	**1.19%**
15	Other Production Exp	**100.00%**	**36.03%**	**54.47%**	**2.39%**	**7.11%**
16	Prod-Stor-Tran-Dis	243,946	150,250	89,741	1,290	2,665
17	Prod-Stor-Tran-Dis	**100.00%**	**61.59%**	**36.79%**	**0.53%**	**1.09%**
18	Rate Base	**100.00%**	**59.99%**	**37.85%**	**0.63%**	**1.54%**
19	Rt Base, w/o Work Cash	168,696	101,053	63,931	1,071	2,641
20	Rt Base, w/o Work Cash	**100.00%**	**59.90%**	**37.90%**	**0.63%**	**1.57%**
21	Transmission & Distribution	218,191	139,855	74,381	1,290	2,665
22	Tran & Distrib	**100.00%**	**64.10%**	**34.09%**	**0.59%**	**1.22%**
23	Labor w/o A&G	4,545	2,981	1,446	32	86
24	Labor w/o A&G	**100.00%**	**65.58%**	**31.83%**	**0.70%**	**1.89%**
	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%**

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

ALLOCATORS

External Allocators

			ND	Res	C&I	Sm Int	Lg Int
	Customer-Related						
1	Bills		776,092	659,380	115,772	652	288
2	Meter & Regul Weightings			1.00	2.57	14.52	28.07
3	Meter (Wtd Bills)		974,443	659,380	297,508	9,470	8,085
4	Service Weightings			1.00	2.38	6.86	6.33
5	Service (Wtd Bills)		941,329	659,380	275,655	4,472	1,822
6	Records & Collect Weightings			1.00	1.17	61.08	61.08
7	Records & Collect (Wtd Bills)		851,987	659,380	135,188	39,827	17,592
8	Cust Information Weightings			1.00	1.25	63.71	29.86
9	Cust Information (Wtd Bills)		854,319	659,380	144,802	41,537	8,600
10	Customers		100.00%	84.96%	14.92%	0.08%	0.04%
11	Meter & Regul Study		100.00%	67.67%	30.53%	0.97%	0.83%
12	Service Study		100.00%	70.05%	29.28%	0.48%	0.19%
13	Record & Coll Study		100.00%	77.39%	15.87%	4.67%	2.06%
14	Uncollectibles Study		100.00%	82.99%	17.01%	0.00%	0.00%
15	Cust Inform Study		100.00%	77.18%	16.95%	4.86%	1.01%
	Energy-Related						
16	Cal Yr Sales Dkt, W/o Trans		12,668,979	4,285,129	6,418,871	497,468	1,467,512
17	Transportation Dkt		1,668,899	0	1,571,440	0	97,460
18	Cal Yr Sales Dkt, W/ Trans	31.1%	14,337,878	4,285,129	7,990,310	497,468	1,564,971
19	CIP Exempt Dkt		0	0	0	0	0
20	Sales Dkt, W/o CIP Exempt		14,337,878	4,285,129	7,990,310	497,468	1,564,971
21	Sales, W/o Transp		100.00%	33.82%	50.67%	3.93%	11.58%
22	Sales, W/ Transp		100.00%	29.89%	55.73%	3.47%	10.91%
23	Sales, W/o CIP Exempt		100.00%	29.89%	55.73%	3.47%	10.91%
	Demand-Related						
24	Design Day Demand Dkt		126,491	51,053	75,438	0	0
25	Avg Daily Firm Dkt, W/ Trans		33,631	11,740	21,891	0	0
26	Excess Design Day		92,860	39,313	53,547	0	0
27	Design Day		100.00%	40.36%	59.64%	0.00%	0.00%
28	Excess Design Day		100.00%	42.34%	57.66%	0.00%	0.00%
	Miscellaneous (only alloc to class, not component)						
29	Present Retail Revenue		89,990	35,610	45,208	2,472	6,700
30	Gross Receipts Tax		100.00%	56.19%	36.38%	4.35%	2.45%
31	Present Retail Revenue		100.00%	39.57%	50.24%	2.75%	7.45%
32	Late Payment Penalty		100.00%	89.95%	9.50%	0.33%	0.22%

CLASS COST OF SERVICE STUDY ($000); TEST YEAR 2024

	Capital Structure	**Rate**	**Ratio**	**Wtd Cost**
1	Long Term Debt	4.54%	47.38%	2.15%
2	Short Term Debt	7.72%	0.12%	0.01%
3	Debt Total	4.55%	47.50%	2.16%
4	Preferred Stock	0.00%	0.00%	0.00%
5	Common Equity	10.20%	52.50%	5.36%
6	Required Rate of Return		100.00%	7.52%
7	ND Combined State & Fed Tax Rate	23.84%		
8	1 / (1 - Tax Rate) Factor	131.30%		
9	Tax Rate / (1 - Tax Rate) Factor	31.30%		

Northern States Power Company
State of North Dakota Gas Jurisdiction
Minimum System Study

Pipe Material	Diameter	Pipe Type	Footage	Total Cost Normalized 2023	2023 Normalized Cost per Foot	Total Cost Assuming Cost of 2 inch Plastic or Steel Pipe
Plastic	<=2"	Main Gas Plastic <=2"	4,823,192	$62,498,169	$12.96	$62,498,169
	> 2" to 4"	Main Gas Plastic > 2" to 4"	880,385	$21,553,420	$24.48	$11,407,891
	> 4" to 8"	Main Gas Plastic > 4" to 8"	647,724	$18,296,827	$28.25	$8,393,106
	>10" to 12"	Main Gas Plastic >10" to 12"	1,300	$174,198	$134.00	$16,845
	>12" to 20"	Main Gas Plastic >12" to 20"	0	$0	$0.00	$0
Steel	<=2"	Main Gas Steel <=2"	416,625	$31,260,092	$75.03	$31,260,092
	> 2" to 4"	Main Gas Steel > 2" to 4"	243,780	$29,809,382	$122.28	$18,291,234
	> 4" to 8"	Main Gas Steel > 4" to 8"	284,711	$54,160,945	$190.23	$21,362,357
	> 8" to 10"	Main Gas Steel > 8" to 10"	2,497	$156,654	$62.74	$187,354
	>10" to 12"	Main Gas Steel >10" to 12"	90,219	$16,599,599	$183.99	$6,769,287
	>12" to 20"	Main Gas Steel >12" to 20"	28,471	$14,020,398	$492.44	$2,136,228
Total			**7,418,904**	**$248,529,684**	**$33.50**	**$162,322,564**

Type	Footage	Share
Plastic	6,352,601	85.63%
Steel	1,066,303	14.37%
Total	**7,418,904**	**100%**

Minimum System % Assuming 2 Inch Plastic or Steel >>>	**65.3%**
Demand Adjustment	**16.1%**
Adjusted Minimum System % Assuming 2 Inch Plastic or Steel >>>	**49.2%**

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY	)	Case No. PU-23-___
2024 NATURAL GAS RATE INCREASE	)	
APPLICATION	)	
	)	
	)	

AFFIDAVIT OF
Christopher J. Barthol

I, the undersigned, being first 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 14 day of December, 2023.

Jodi Lynn Yanz
____
Notary Public
My Commission Expires:

JODI LYNN YANZ
NOTARY PUBLIC
MINNESOTA
My Commission Expires 01/31/2027