Direct Testimony and Schedules
Michelle M. Terwilliger

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. G002/GR-23-413
Exhibit___(MMT-1)

Rate Design

November 1, 2023

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michelle M. Terwilliger. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Northern States Power Company – Minnesota (NSPM or the Company). My title is Pricing Consultant.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for the Company as a Pricing Consultant and formerly as a Principal Rate Analyst in Regulatory Affairs for more than ten years. Previously, I worked for Midwest Energy, Inc. as Manager of Customer Accounting and North Central Public Service Co., a gas utility, as a Rate Analyst and rate witness before the Iowa Public Utilities Commission. I received my bachelor's degree in accounting from the University of Minnesota. A statement of my qualifications and experience is provided as Exhibit___(MMT-1), Schedule 1.

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

A. My testimony presents the Company's proposed rate design for recovering the revenue requirement provided by Company witness Benjamin Halama in his Direct Testimony for the test year ending December 31, 2024 for NSPM's State of Minnesota natural gas jurisdiction. The CCOSS provided by Company witness Christopher J. Barthol was the starting point for the apportionment of the retail test year revenue requirement among the rate classes. I also describe certain proposed tariff changes. Finally, I provide information on rate design related compliance requirements.

II. RATE DESIGN GOALS

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

A. The primary natural gas rate design objectives are:

1) To collect total revenues sufficient to recover the Company's test year cost of service, including a reasonable return on investment;
2) To achieve fair and equitable rate levels that reflect the cost of providing service to each customer class, as supported by the Class Cost of Service Study (CCOSS);
3) To encourage efficient and economic energy use;
4) To moderate billing impacts, be understandable and provide customer choices; and
5) To provide value-based pricing and service conditions, where needed, to allow the Company's natural gas services to be competitive with other energy sources.

III. TEST YEAR REVENUES

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

A. The 2024 test year revenues, applying present and proposed rates for the Company's gas utility-Minnesota jurisdiction, are $617.81 million and $676.83 million respectively. The $59.0 million difference between the two revenue levels is the revenue deficiency supported by Company witness Halama's testimony. Present rates refer to the rates authorized in the Company's last natural gas rate case, Docket No. G002/GR-21-678. The proposed rates are designed to produce an increase in retail revenues of $59.0 million. Forecasted sales and transportation service volumes for the 2024 test year, provided by Company witness John M. Goodenough, were applied to both the present and proposed rates to obtain these test year revenues.

As Company witness Halama explains in his Direct Testimony, the level of Conservation Improvement Program (CIP) expenditures in the jurisdictional cost-of-service study is equal to the level of CIP revenues in base rates. The amount of the 2024 test year CIP revenues in base rates is included in Exhibit___(MMT-1), Schedule 2.

IV. DESCRIPTION OF NSPM REGULATED NATURAL GAS SERVICES

Q. WHAT GENERAL CATEGORIES OF SERVICE DOES NSPM PROVIDE TO ITS NATURAL GAS CUSTOMERS IN MINNESOTA?

A. The Company provides sales service and transportation service. Sales service is a "bundled" gas utility service offering, where the Company procures wholesale natural gas for customers, procures the necessary 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 the Company's town border station(s). The Company then delivers 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 potential for interruption and the competitive alternatives. The vast majority of the Company's customers take firm, bundled sales service.

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

A. The Company's Services include the following:

<u>Services</u>

Firm Sales
Residential
Small Commercial Firm
Large Commercial Firm
Small Commercial Demand Billed
Large Commercial Demand Billed

Interruptible Sales
Small Volume Interruptible
Medium Volume Interruptible
Large Volume Interruptible

Firm and Interruptible Transportation
Large Firm Transportation
Small Interruptible Transportation
Medium Interruptible Transportation
Large Interruptible Transportation

V. REVENUE REQUIREMENT APPORTIONMENT

Q. HOW WAS THE PROPOSED REVENUE REQUIREMENT APPORTIONMENT DEVELOPED?

A. As mentioned above, the CCOSS provided by Company witness Barthol was the starting point for the apportionment of the retail test year revenue requirement among the rate classes. The CCOSS indicates that the majority of classes should receive a rate decrease, and the Residential class should receive an increase equal to 77 percent of the deficiency in this case. However, the Company tempered the goal of setting rates at embedded costs by applying the other goals I described earlier, such as emphasizing value/competitive-based pricing for competitive services, market considerations, and limiting rate increases to moderate levels. Consequently, the Company used the CCOSS as a guideline, but not as a final determinant for revenue apportionment by class. A summary page from the CCOSS showing the difference between current revenues and costs is provided in Exhibit___(MMT-1), Schedule 3.

The Company's first step in developing the class apportionment was to review the market price forecasts of the customers' typical competitive alternatives and consider the value of Interruptible service compared to Firm service, and then determine the revenue responsibility for the Interruptible classes. The Company balanced the increase to the Interruptible class with the corresponding increase to the Interruptible Transportation class, as I describe later in my testimony. The value-based approach to pricing Interruptible service results in the recovery of more than this class's embedded cost of service. I discuss the specific procedure the Company used to develop Interruptible prices later in my testimony.

The Company then apportioned the remaining revenue requirement among the Firm classes. The Company proposes a 10.3 percent increase to the Residential class, which is approximately 27 percent movement towards cost.[1] The CCOSS results indicated that the Demand class rates are currently set above their cost of service, and the Commercial class is slightly below cost. Based on this, the Company proposes a Commercial class increase of 8.9 percent and a lower increase of 7.7 percent for the Demand class. While the average Firm customer increase is 9.6 percent, the Company proposes different non-gas revenue percent increases for each of the Firm service classes. The Company's goal was to recover as closely as possible the costs of service imposed by each class, while avoiding sharp increases in rates. The Company's proposed revenue responsibility allocation for the Residential class will eliminate approximately 83 percent of the difference between present rates and the test year embedded cost of service.

Finally, the Company reviewed the apportionment to ensure that longstanding rate relationships between Firm and Interruptible rate classes, as well as between Sales Service and Transportation rate classes, were maintained. For example, Interruptible rates must be set at a discount relative to firm rates to reflect the less reliable nature of interruptible service. In addition, relationships within the small, medium, and large categories of a class should be maintained. Also, the Company's goal is to remain indifferent to a customer's choice regarding gas supplier, and therefore the proposed non-gas margins for corresponding Sales

[1] Movement towards cost is defined as the relative position between a class increase set at the average retail increase (no movement towards cost) and a class increase set at the class cost indicated by the CCOSS (full movement to cost).

and Transportation Service are equal. The resulting apportionment is provided in Exhibit___(MMT-1), Schedule 4.

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

A. Table 1 provides the overall class impacts of the Company-proposed apportionment and compares it to the CCOSS-indicated apportionment. The apportionment with gas costs is provided in Schedule 4.

Table 1
Revenue Apportionment

	($000)		
Customer Class	**Present Revenues**	**CCOSS Costs of Service**	**Proposed Revenue**
Residential	$364,900	$410,438	$402,667
% increase		12.5%	10.3%
Commercial	$179,310	$181,246	$194,167
% increase		1.1%	8.3%
Demand	$19,847	$19,423	$21,382
% increase		-2.1%	7.7%
Interruptible	$37,592	$35,455	$40,111
% increase		-5.7%	6.7%
Transport	$7,374	$7,305	$9,459
% increase		-0.9%	28.3%
Generation	$8,783	$22,964	$8,889
% increase		161.4%	1.2%
Other Revenues			$157
% increase			
Total	$617,806	$676,832	$676,832
% increase		9.6%	9.6%

Q. WHAT FACTORS CONTRIBUTE TO THE NON-GAS INCREASE?

A. Both the increased revenue requirement and the transfer, or roll-in, of rider expenditures to base rates impact the non-gas increase. As Company witness Halama explains in his direct testimony, Present Revenues include revenues related to the CIP and GUIC riders that are being moved into base rates. The roll-in of GUIC and CIP rider costs resulted in increased distribution charges to recover those rider charges. Customers have currently been paying for these costs through these riders, so the portion of the base rate increase associated with the rider roll-ins does not increase their overall bill. The CIP/GUIC test year revenue adjustments are provided in Schedule 2.

Q. DO YOU PROPOSE A REVENUE APPORTIONMENT FOR GAS COST REVENUES?

A. No. The Base Cost of Gas establishes the apportionment of gas cost revenues. Gas cost revenues are shown on certain schedules in my testimony to demonstrate the overall bill impact of the non-gas rate increase.

VI. OVERALL CLASS IMPACTS

Q. PLEASE DESCRIBE EXHIBIT___(MMT-1), SCHEDULES 5, 6, AND 7.

A. In compliance with the requirements of Minn. R. 7825.4300, Exhibit___(MMT-1), Schedule 5 summarizes the present and proposed test year revenues and contains the test year number of customers, sales, present and proposed test year rates, the Base Cost of Gas rates, and the resulting revenues. This information is provided in summary for each class (page 1); and for each rate component charged to each class (pages 2 through 5). Exhibit___(MMT-1), Schedule 6 contains the present and proposed rates for the test year revenue requirement. Exhibit___(MMT-1), Schedule 7 provides the resulting revenues under the proposed test year revenue requirement compared to the class revenue requirements as determined by the CCOSS.

VII. REVENUE RECOVERY

Q. PLEASE DESCRIBE HOW THE COMPANY STRUCTURES RATES CURRENTLY.

A. The Company's current rates are structured as either two- or three-part rates. Two-part rates consist of a monthly fixed Customer Charge and a volumetric Distribution Charge applied to a customer's use during the billing period. Three-part rates add a Demand Charge that is assessed on a customer's peak day demand. In addition, the Company collects a Cost of Gas charge that reflects the Base Cost of Gas plus the Purchased Gas Adjustment (PGA) for changes in wholesale gas, transportation, and storage costs in each month. Although the Base Cost of Gas will be restated in conjunction with this proceeding, the fundamental rate design issues in this proceeding relate to recovery of the Company's non-commodity costs of providing retail distribution service.

Q. WHY DO YOU RECOMMEND CHANGES TO THE RELATIONSHIP BETWEEN RATE COMPONENTS?

A. The shortcoming of our current pricing is that we recover a significant percentage of fixed costs through volumetric charges, which is not the case for other market participants and in other jurisdictions. In North Dakota, we recover all residential costs through the fixed customer charge with no distribution charge. Similarly, interstate natural gas pipelines recover 100 percent of their fixed costs through fixed charges. By contrast, under our present gas rate design, the Company collects only 38 percent of its fixed costs through fixed charges such as the Customer Charge, resulting in an intra-class subsidy discussed in the Residential Service section below. This deficiency causes several problems; for example, an artificially low customer charge could lead to customers choosing to install natural gas as a backup energy source along with another primary source of heat. These choices could frustrate the goal of efficient and economic energy use.

Q. HOW DO YOU PROPOSE TO ADDRESS THE CURRENT DEFICIENCY IN THE RATE STRUCTURE?

A. The Company proposes an increase in the Residential, Small Commercial Firm, and Small Interruptible Customer Charges because the Customer Charges in these classes are below the appropriate cost-based levels. If the Commission were to adopt a lower Customer Charge than the Company proposes, the Distribution Charge would need to be higher than the Company's proposal to achieve the same level of overall revenue increase.

VIII. SUMMARY OF RATE DESIGN PROPOSALS

A. Residential Service

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

A. The Company is proposing to increase the monthly Residential Customer Charge from $9.00 to $11.00 and increase the Distribution Charge from $0.274927 per therm to $0.376599 per therm. I note that $0.033935 per therm of the proposed Distribution Charge is a result of present rider rates being rolled into our proposed rates. This combination of changes will be referred to herein as the "proposed rate structure."

Q. WHY ARE YOU RECOMMENDING A RESIDENTIAL CUSTOMER CHARGE THAT FALLS WELL SHORT OF THE COSTS IMPOSED BY THESE CUSTOMERS?

A. The customer related cost of providing service to Residential customers is \$23.48. I am recommending an increase from \$9.00 to \$11.00. Raising the Customer Charge from \$9.00 to the cost-based level of \$23.48, while appropriate from a cost-causation perspective, would impose a significant percentage increase in the monthly bill for low-use customers. Therefore, my proposal strikes a balance between reducing the inefficiencies in our current Residential pricing, *i.e.,* recovering an inadequate amount of fixed costs through the Customer Charge, and moderating the billing impacts on low-use customers. The CCOSS indicated Customer Charges are shown on line 8 of Schedule 3.

Q. WHY IS IT IMPORTANT TO RECOVER MORE CUSTOMER COSTS IN THE CUSTOMER CHARGE?

A. Recovering customer costs in Customer Charges creates more efficient pricing, promotes stability, and reduces intra-class subsidies.

Customer costs are caused by all customers connected (or being connected) to the Company's gas system (*i.e.,* metering, service lines, meter reading, billing, etc.). Thus, customer costs are not related to the amount of gas a customer uses. Even if a customer uses no gas, the Company incurs essentially the same (or "fixed") level of customer-related costs just to have the customer connected to the gas distribution system. As I discuss in more detail below, it is important to reflect these principles in the customer cost structure.

Q. HOW DOES THE PROPOSED RATE STRUCTURE CREATE MORE EFFICIENT PRICING?

A. When the Customer Charge does not recover an appropriate level of fixed customer costs, the remaining fixed customer costs are recovered in the volumetric Distribution Charge. As a result, even though all customers are causing the fixed costs to be incurred, those who use more gas subsidize the fixed costs of other customers. Recovering more customer costs in the Customer Charge reduces the subsidization, and thus adheres more closely to the principle of cost causation, by allowing each customer to pay a more equitable portion of the fixed costs incurred by the Company to serve them.

For example, even under the Company's present rates, although two customers each impose annual customer costs of $282, a customer using 40 Dekatherm (Dkt)/year would pay for only $218 of these costs, while a customer using 120 Dkt/year would pay $438. In other words, an intra-class subsidy exists.

Q. DOES THE PROPOSED RATE STRUCTURE PROMOTE STABILITY?

A. Yes. By moving the recovery of more fixed costs to the fixed charge, the proposed rate structure creates more stable bills and cost recovery. A lower percentage of the customer's bill would be affected by variability in weather compared to the current structure.

Q. WOULD A MODERATE INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE UNFAIRLY BURDEN LOW-VOLUME USERS?

A. No. As noted above, an increase in the Residential Customer Charge would result in a reduction to the existing subsidy currently provided by high-volume to low-volume Residential users. The modest reduction of this subsidy should not be construed as a burden. It would be more accurate to conclude that high-volume customers are currently burdened because they pay more than their cost of service. Therefore, failing to address this problem would continue to impose an unreasonable burden on high-volume customers. It is appropriate for low-volume users to pay lower bills to the extent their lower usage results in a lower cost of service; but it is not appropriate for low-volume customers to benefit from a subsidy provided by higher-volume customers in the same class.

Q. WHAT EFFECT WOULD THE COMPANY'S PROPOSED RESIDENTIAL RATE DESIGN HAVE ON CONSERVATION?

A. More appropriate cost-based rates should lead to more informed decision-making regarding natural gas usage. Since wholesale gas costs are approximately 55 percent of customers' bills, customers who conserve natural gas usage will continue to be rewarded with lower bills. Rates that better reflect cost should encourage conservation.

Q. WHAT ARE THE RESIDENTIAL CUSTOMER CHARGES IN THE COMPANY'S OTHER JURISDICTIONS?

A. The Residential Customer Charge in North Dakota is $22.25 per month and there is no volumetric Distribution Charge. The proposed Residential Customer Charge is also lower than that currently authorized for Northern States Power Company, a Wisconsin corporation, which has a $14.00 per month Residential monthly charge in Wisconsin and the same as the current $11.00 Residential Customer Charge for Colorado customers of Public Service Company of Colorado.

Q. NORTH DAKOTA HAS THE HIGHEST CUSTOMER CHARGE AND NO DISTRIBUTION CHARGE. HAS THE COMPANY SEEN EVIDENCE IN NORTH DAKOTA THAT THIS RATE STRUCTURE DISCOURAGES CONSERVATION?

A. No. In fact, this rate structure has been in place in North Dakota since 2005 and North Dakota has experienced significant conservation success despite a much higher customer charge. North Dakota Residential average annual usage has decreased from 834 therms in 2006 to 775 therms in 2022, or by 7 percent.

Q. HOW DOES THE COMPANY ADDRESS CONCERNS REGARDING THE IMPACT OF INCREASED CUSTOMER CHARGES ON CUSTOMERS WITH LOW INCOME?

A. The Company offers a natural Gas Affordability Program, which targets customers with low income who may have difficulties paying their gas utility bill.

Q. DO LOW-INCOME CUSTOMERS HAVE USAGE PATTERNS THAT ARE DIFFERENT FROM THE AVERAGE RESIDENTIAL CUSTOMER?

A. No, low-income usage patterns mirror the average Residential usage pattern. Some low-income customers have low energy usage, but other low-income customers have very high energy use. The absence of a relationship between usage and income is shown on the graph included as Exhibit___(MMT-1), Schedule 11. This graph shows the 2022 annual usage against the percentage of bills for all Low-Income Home Energy Assistance Program (LIHEAP) customers and all non-LIHEAP Minnesota residential customers. There is not a substantial difference between the shapes of the two curves. The graph shows that low-income customers use gas in much the same pattern that all residential customers use gas.

Q. WHAT IS THE BILL IMPACT OF THE COMPANY'S OVERALL RATE DESIGN PROPOSALS FOR THE RESIDENTIAL CLASS?

A. The average Residential customer will experience a 10.3 percent increase in their bill. A comparison of bills for various usage levels under present and proposed rates is shown on Exhibit___(MMT-1), Schedule 8. Considering just the smaller non-gas portion of the Residential bill, the average increase is 22.0 percent. This proposal moves the Residential class approximately 27 percent closer to paying their full cost of service than under current rates.

B. Commercial Firm Service

Q. WHAT CHANGES ARE YOU PROPOSING TO THE FIRM COMMERCIAL RATES?

A. The Company is proposing to increase the Small Commercial Customer Charge from $20.00 to $30.00 and no change to the Large Commercial Customer Charge of $50.00. The increase in the Small Commercial Customer Charge is justified by the Company's CCOSS. To achieve overall rate apportionment goals, the Company is proposing to increase the per therm Distribution Charges from $0.219738 to $0.278538 for Small Commercial service and from $0.184101 to $0.265771 for Large Commercial service.

C. Demand Billed Service

Q. WHAT CHANGES ARE YOU PROPOSING FOR DEMAND BILLED RATES?

A. The Company is not proposing changes to the Small and Large Demand Billed Customer Charges based on the cost levels indicated by the CCOSS. The Distribution Charges for the Demand Billed Services were set at the Distribution Charge for the Medium Interruptible customers. This general relationship has been in effect since the Company's 1992 rate case (Docket No. G002/GR-92-1186) and is reasonable. The rates on the two tariffs should be comparable except for the Demand Charge, which reflects the firm nature of the Demand Billed Service. The Demand Charge was increased from $0.882000 to $0.932000 per therm of billing demand to achieve an overall average bill increase of 7.7 percent.

D. Interruptible Sales Service

Q. WHAT ARE THE GOALS OF THE COMPANY'S PROPOSED INTERRUPTIBLE GAS RATES?

A. The primary goals are as follows:

- First, Interruptible rates should reflect the anticipated value of service to the customer. This goal was accomplished by pricing Interruptible service at a rate competitive with the cost of alternate fuels available to these customers. The upper limit used for the Interruptible commodity pricing was the price of No. 2 fuel oil, since most of these customers use No. 2 fuel oil as their primary alternate fuel.
- Second, Interruptible prices should reflect 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.
- Third, Interruptible customers should not be subsidized by other classes of service. Therefore, Interruptible rates should recover at least the Company's base cost of gas plus variable operating and maintenance expenses.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS INTERRUPTIBLE SERVICE TARIFF IN THIS CASE?

A. Yes. As discussed by Company witness Scott S. Hults, the Company is proposing to modify its existing Interruptible Service Rate Schedule and Agreement for interruptible sales customers to provide for two tiers of interruptible service, Tier I and Tier II, in compliance with the Commission's Order dated February 17, 2023 in Docket No. G999/CI-21-135. Company witness Hults discusses these two tiers of interruptible service and the Company's proposed distribution rates for each set of interruptible customers. My testimony focuses on the interruptible rates for the Company's proposed Tier I Interruptible Customers.

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

A. First, looking at the alternate fuel prices of No. 2 fuel oil of $1.29345 per therm, it far exceeds the Interruptible commodity pricing. Therefore, the Firm rates become the upper limit for Interruptible rates and as shown in Table 2 below, the Company has maintained a similar level of discount as current rates. Next, the Company looked at the CCOSS results. The current Customer Charges for the Medium and Large Interruptible Service classes exceed the CCOSS average of customer-related expenses. Consequently, the Company proposes no increase in these charges. The Company is proposing to increase the Small Interruptible Customer Charge from $150 to $170 to reflect the indicated CCOSS customer related cost.

The proposed Distribution Charge established for the Medium Interruptible Service was designed to generate a 7.6 percent overall rate increase for the class. The proposed Distribution Charge established for the Large Interruptible Service was designed to reflect a lower cost of service than the Medium Interruptible Service class and to generate an overall increase of 5.8 percent for the class. The Distribution Charge for the Small Interruptible Service class was increased from $0.148846 to $0.205463 per therm. These increases were designed to maintain a reasonable discount, similar to that reflected in present rates, from the corresponding Firm service options available to these customers. The various components of the Interruptible rates are identified in Schedule 5, page 4.

Table 2 below illustrates the current and proposed level of discount between Firm and Interruptible Sales Service.

Table 2
Average Bill Comparison-Commercial Firm and Interruptible Classes

Class	Monthly Therm Use	Avg Bill - Present Rates	Avg Bill - Proposed Rates
Large Commercial Firm	1,311	$960	$1,033
Small Interruptible	1,311	$843	$913
% Discount		-12%	-12%
Small Commercial Demand Billed	7,765	$5,419	$5,825
Small Interruptible	7,765	$4,253	$4,570
% Discount		-22%	-22%
Large Commercial Demand Billed	17,821	$11,897	$12,818
Medium Interruptible	17,821	$8,392	$9,145
% Discount		-29%	-29%

As shown in Table 2, Interruptible discounts are being maintained at the same level as current rates.

Q. HOW DOES THE SYSTEM BENEFIT FROM 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, this results in greater reliability because during times when the supply or capacity of the gas system is at risk, the gas that would have been needed to serve Interruptible customers can be used to serve other customers. This also can potentially reduce costs for all customers since depending on when a curtailment is called, the Company can plan for less firm gas than would have otherwise been required.

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

A. Yes. The proposed Interruptible rates would recover $4.5 million above the CCOSS revenue requirement for these customers, thereby reducing the residual costs that must be recovered from firm customers.

Q. HAS THE COMPANY RETAINED THE FLEXIBLE PRICING PROVISIONS FOR ITS INTERRUPTIBLE SALES TARIFFS?

A. Yes. The Company proposes to retain the rate flexibility authorized in the 1985 general gas rate case (Docket No. G002/GR-85-108) for the Flexible Distribution Charge ranges in the Interruptible Service tariff. As stated in the tariff, the Flexible Distribution Charge applies for Customers, who normally would be served on the fixed rate but are placed on the flexible rate because: (1) the customer requests flexible rate service, (2) for pricing reasons, the customer uses a non-gas alternate energy supply/service from a supplier not regulated by the Commission, or (3) the customer uses gas from a supplier not regulated by the Commission.

For those customers on the Flexible Distribution Charge, the midpoint of the proposed range is the applicable fixed rate explained above. The floor has been set at the variable Operation and Maintenance (O&M) cost (which is the incremental cost of providing service), as required by Minn. Stat. § 216B.163, subd. 4(1). The ceiling has been designed so that the rate may be increased by as much as it may be discounted from the fixed rate.

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 the Company will be indifferent to the customer's choice of gas procurement (*i.e.,* Company sales gas or gas purchased from a third-party marketer). Therefore, my explanation of the proposed Customer Charges, Distribution Charges, and Distribution Demand charges for Sales customers also holds true for the corresponding Transportation rates.

Q. DOES THE CCOSS SUPPORT LINKING TRANSPORTATION RATES TO THE CORRESPONDING SALES SERVICE?

A. Yes. In general, customers eligible for these rate options are similarly sized. The Company provided the Transportation specific category in the CCOSS in response to a compliance requirement. Since there are only three to fifteen customers in these classes, annual results are highly dependent on the specific customers currently in the class, and the results could be very different if one or more customers switched rate classes. Therefore, the Company's approach to link the Transportation rates to the corresponding Sales rate should be continued.

Q. WHY IS THE OVERALL INCREASE IN TRANSPORTATION RATES HIGHER THAN INTERRUPTIBLE RATES?

A. The Transportation class increase is higher than the Interruptible because the Transportation customers purchase their gas supply from a third party; thus, their Xcel Energy bill only consists of non-gas components causing their increase to appear higher compared to the average sales service increases.

IX. OTHER TARIFF CHANGES

Q. WHAT OTHER TARIFF CHANGES DOES THE COMPANY PROPOSE?

A. Xcel Energy is proposing a number of changes to tariff sheets in its Minnesota Gas Rate Book. Exhibit___(MMT-1), Schedule 9 contains a list and a summary of the proposed tariff changes. The proposed tariffs are included in redline and non-redline format in the volume entitled "Proposed Tariffs" of our application. These changes are discussed below.

Q. ARE ANY OTHER WITNESSES SPONSORING CHANGES IN THE TARIFF BOOK?

A. Yes. Company witness Hults is addressing several changes in the Gas Rate Book, including:

- Adding optional new Interruptible rates for customers for potential economic curtailments;

- Two proposed tariff revisions in Section 6, General Rules and Regulations, providing language with respect to safety and clarifications for customers; and
- Minor updates and corrections to forms included in Section 7, Contract and Agreement Forms.

For convenience purposes, all proposed tariff changes have been included together in the volume entitled "Proposed Tariffs" of our application.

X. COMPLIANCE REQUIREMENTS

Q. PLEASE ADDRESS ANY COMPLIANCE REQUIREMENTS FROM ORDERS RELATED TO RATE DESIGN.

A. I will address the compliance issues related to the following two items:

- Identify CIP costs not recovered from Flexible rates due to rate discounting, and
- Prepare a separate End User Allocation Service Cost (EUAS) Study.

Q. ARE THERE CIP COSTS THAT ARE NOT BEING RECOVERED DUE TO RATE DISCOUNTING?

A. No. Only customers with an exemption granted by the Commissioner of the Department of Commerce are not required to contribute toward recovery of CIP costs.

Q. DID THE COMPANY PREPARE A SEPARATE EUAS STUDY AS REQUIRED BY DOCKET NO. G002/GR-06-1429?

A. Yes. The cost study is attached as Exhibit___(MMT-1), Schedule 10. The resulting study demonstrates the current charge could be slightly reduced, however, since the cost study is very sensitive to the number of customers currently taking EUAS service, I recommend not changing the monthly rate of $75 at this time.

Q. WHAT DO THE CCOSS RESULTS INDICATE FOR THE STAND-ALONE GENERATION CLASS?

A. For the electric Generation customers (three plants) taking Sales service from the Company, the CCOSS indicates they are presently paying more than embedded cost. The CCOSS indicates that the Generation customers (four plants) taking Transportation service from the Company are paying under embedded cost rates. Three of these customers are taking service pursuant to a long-term contract awarded to the Company's natural gas operations through competitive bidding processes. Service to these three customers required main extensions and the Company was not the only supplier available to these customers. The long-term contract price justified the Company incurring the cost of the extensions and also provided a reasonable contribution, providing a benefit to our other natural gas customers. The lower gas costs also benefit our electric customers.

XI. CONCLUSION

Q. COULD YOU SUMMARIZE THE PROPOSALS AND RECOMMENDATIONS OF YOUR TESTIMONY?

A. Yes. My testimony included the following proposals:

- The Company has proposed a reasonable apportionment of revenue requirements by customer class that provides a moderate movement toward the cost of service.
- The Company's proposed rates are reasonable, consistent with its rate design objectives, and improve customer equity.
- The Company has also proposed various reasonable changes to its tariff.
- Finally, my testimony discusses how the Company has fulfilled the requirements of two Commission-ordered compliance items.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Michelle M. Terwilliger

OVERVIEW

My qualifications include more than 10 years of experience with Xcel Energy and its predecessors in the areas of rate analysis, pricing and rate design. My current responsibilities at Xcel Energy include Rate Design work conducted in support of the Company's rate cases and providing rate analysis and pricing support and other related analyses for the utility operating subsidiaries of Xcel Energy. I have served as a rate case witness in Iowa.

PROFESSIONAL EXPERIENCE

Pricing Consultant, Xcel Energy, NSPM	2022 – Present
Principal Rate Analyst; Xcel Energy, NSPM	2013 – 2022
Accountant; Christ Presbyterian Church	2012 – 2013
Program Coordinator; Prayer Ventures	2010 – 2012
Assistant Manager; Pathway Books/Music	2007 – 2010
Owner, Le Nantais French Delicatessen	1988 – 1993
Manager of Customer Accounting; Midwest Energy, Inc.	1986 – 1988
Rate Analyst; North Central Public Service Co.	1985 – 1986
Staff Accountant; North Central Public Service Co.	1983 – 1985

EDUCATIONAL BACKGROUND

University of Minnesota; BS Accounting	1983

TEST YEAR RIDER ROLL INS
Test Year Ending December 31, 2024

CIP Rider

Line		
1	Test Year Sales (therms)	1,187,786,616
2	Test Year CIP Exempt Sales (therms)	407,344,535
3	Test Year CIP-related Sales (therms)	780,442,081
4	CCRC used to determine CIP Base Revenues	$0.023947
5	Test Year CIP Base Revenue in Present Revenues (Line 3 x Line 4)	$18,689,247
6	Test Year CIP Expense	$28,618,208
7	Test Year CIP Adjustment (Line 6 - line 5)	$9,928,962
8	Per Therm Adjustment to adjust CIP Revenues (Line 7 / Line 3)	$0.012722
9	Per Therm CCRC in Test Year Base Rates (Line 6 / Line 3)	$0.036669

GUIC Rider

	GUIC Allocator	GUIC Allocation	Therms	Factors
Res	64.1619%	$8,415,006	396,701,840	0.021212
Comm Firm	24.1303%	$3,164,754	236,670,332	0.013372
Dmd Billed	6.6396%	$870,801	436,729,625	0.001994
Interruptible	5.0682%	$664,708	117,684,820	0.005648
Test Year GUIC Expense		$13,115,270	1,187,786,616	

COMPARISON OF CURRENT REVENUES AND COSTS BY CLASS ($000)
Test Year Ending December 31, 2024

		1=2+15	2=3+11	3=4+5+8	4	5=6+7	6	7	8=9+10	11=12>>14	15=16+20	16=17>>19	20=21+22	21	22
	Equal Return vs Present														
	Operating Revenue Requirement	**Minn**	**Retail**	**Firm**	**Res**	**C&I Tot**	**Sm C&I**	**Lg C&I**	**Dmd Tot**	**Inter Tot**	**Non-Retail**	**Tran Tot**	**Gener Tot**	**Sys Gen**	**Tran Gen**
1	Return On Rate Base	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
2	Equalized Total Retail Rev	676,832	646,563	611,108	410,438	181,246	49,199	132,047	19,423	35,455	30,269	7,305	22,964	1,193	21,771
3	Present Total Retail Revenue	617,806	601,649	564,057	364,900	179,310	46,550	132,760	19,847	37,592	16,157	7,374	8,783	1,635	7,149
4	Revenue Deficiency	59,026	44,914	47,051	45,538	1,936	2,650	-714	-423	-2,137	14,111	-69	14,181	-442	14,622
5	Deficiency / Pres Total Retail Rev	9.55%	7.47%	8.34%	12.48%	1.08%	5.69%	-0.54%	-2.13%	-5.68%	87.34%	-0.94%	161.45%	-27.02%	204.54%
	Internal Retail Revenue Reqt														
6	Customer Retail Revenue Requirement	143,160	143,090	142,589	127,894	14,424	8,874	5,550	271	501	70	54	16	9	7
7	Average Monthly Customers	490,675	490,640	490,405	453,981	36,278	24,758	11,520	147	235	35	26	9	5	4
8	Revenue Requirement $ / Mo / Cust	24.31	24.30	24.23	23.48	33.13	29.87	40.15	153.76	177.61	166.55	173.30	147.06	153.06	139.55
9	Capacity Retail Revenue Requirement	144,289	119,386	116,252	70,871	40,989	10,735	30,254	4,392	3,133	24,903	5,079	19,824	229	19,595
10	Annual Dkt Sales	118,778,662	74,308,884	66,305,772	39,670,184	23,667,033	5,540,428	18,126,605	2,968,555	8,003,112	44,469,778	12,284,918	32,184,860	215,753	31,969,107
11	Revenue Requirement $ / Dkt	1.21	1.61	1.75	1.79	1.73	1.94	1.67	1.48	0.39	0.56	0.41	0.62	1.06	0.61
	Capacity - Sub Classification														
12	Capacity - Base Revenue Requirement	40,680	28,339	25,206	15,026	9,041	2,108	6,934	1,138	3,133	12,341	4,677	7,664	84	7,580
13	Capacity - Seasonal Revenue Requirement	71,515	63,211	63,211	38,885	22,115	6,036	16,079	2,211	0	8,304	196	8,108	108	8,000
14	Peak Shaving Revenue Requirement	32,094	27,836	27,836	16,961	9,833	2,591	7,242	1,042	0	4,258	207	4,052	37	4,015
15	Base Rev Requirement $ / Dkt	0.34	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.39	0.28	0.38	0.24	0.39	0.24
16	Seasonal Rev Requirement $ / Dkt	0.60	0.85	0.95	0.98	0.93	1.09	0.89	0.74	0.00	0.19	0.02	0.25	0.50	0.25
17	Peak Shave Rev Requirement $ / Dkt	0.27	0.37	0.42	0.43	0.42	0.47	0.40	0.35	0.00	0.10	0.02	0.13	0.17	0.13
18	Energy Retail Revenue Requirement	38,792	34,356	30,646	18,182	11,085	2,598	8,487	1,378	3,710	4,436	2,172	2,265	95	2,169
19	Revenue Requirement $ / Dkt	0.33	0.46	0.46	0.46	0.47	0.47	0.47	0.46	0.46	0.10	0.18	0.07	0.44	0.07
20	Total Internal Retail Revenue Requirement	326,240	296,831	289,487	216,948	66,498	22,206	44,292	6,041	7,344	29,409	7,305	22,104	333	21,771
21	Revenue Requirement $ / Dkt	2.75	3.99	4.37	5.47	2.81	4.01	2.44	2.03	0.92	0.66	0.59	0.69	1.55	0.68
22	Revenue Requirement $ / Mo / Cust	55.41	50.42	49.19	39.82	152.75	74.74	320.41	3,430.34	2,605.21	70,022.31	23,413.91	204,668.79	5,557.50	453,557.91
	External Retail Revenue Reqt														
23	Capacity Revenue Requirement	79,684	79,582	79,582	48,191	28,441	6,786	21,655	2,950	0	102	0	102	102	0
24	Energy Revenue Requirement	270,750	269,993	241,882	145,153	86,297	20,202	66,095	10,432	28,111	757	0	757	757	0
25	Total External Revenue Requirement	350,434	349,575	321,464	193,344	114,738	26,988	87,750	13,382	28,111	860	0	860	860	0
26	Cap Revenue Requirement $ / Dkt	0.67	1.07	1.20	1.21	1.20	1.22	1.19	0.99	0.00	0.00	0.00	0.00	0.47	0.00
27	Ener Revenue Requirement $ / Dkt	2.28	3.63	3.65	3.66	3.65	3.65	3.65	3.51	3.51	0.02	0.00	0.02	3.51	0.00
28	Tot Revenue Requirement $ / Dkt	2.95	4.70	4.85	4.87	4.85	4.87	4.84	4.51	3.51	0.02	0.00	0.03	3.98	0.00
	Total Retail Revenue Reqt														
29	Customer Revenue Requirement	143,160	143,090	142,589	127,894	14,424	8,874	5,550	271	501	70	54	16	9	7
30	Capacity Revenue Requirement	223,973	198,967	195,834	119,062	69,430	17,521	51,909	7,342	3,133	25,005	5,079	19,926	331	19,595
31	Energy Revenue Requirement	309,542	304,349	272,528	163,336	97,382	22,800	74,582	11,810	31,820	5,194	2,172	3,022	853	2,169
32	Total Revenue Requirement	676,675	646,406	610,951	410,292	181,236	49,194	132,041	19,423	35,455	30,269	7,305	22,964	1,193	21,771
33	Customer Revenue Reqt $ / Dkt	1.21	1.93	2.15	3.22	0.61	1.60	0.31	0.09	0.06	0.00	0.00	0.00	0.04	0.00
34	Demand Revenue Reqt $ / Dkt	1.89	2.68	2.95	3.00	2.93	3.16	2.86	2.47	0.39	0.56	0.41	0.62	1.54	0.61
35	Energy Revenue Reqt $ / Dkt	2.61	4.10	4.11	4.12	4.11	4.12	4.11	3.98	3.98	0.12	0.18	0.09	3.95	0.07
36	Total Revenue Reqt $ / Dkt	5.70	8.70	9.21	10.34	7.66	8.88	7.28	6.54	4.43	0.68	0.59	0.71	5.53	0.68
	Proposed Return vs Present														
37	Proposed Total Retail Revenue	676,832	658,485	618,373	402,813	194,178	51,338	142,839	21,382	40,112	18,347	9,459	8,889	1,649	7,239
38	Revenue Deficiency	59,026	56,836	54,316	37,913	14,867	4,788	10,079	1,535	2,520	2,190	2,084	105	15	90
39	Deficiency / Pres Total Oper Revenue	9.55%	9.45%	9.63%	10.39%	8.29%	10.29%	7.59%	7.74%	6.70%	13.55%	28.27%	1.20%	0.91%	1.27%
	Proposed Return vs Equal														
40	Revenue Difference	0	11,922	7,265	-7,625	12,932	2,139	10,793	1,959	4,657	-11,922	2,153	-14,075	456	-14,532
41	Difference / Tot Equal Revenue"	0.00%	1.84%	1.19%	-1.86%	7.13%	4.35%	8.17%	10.08%	13.13%	-39.39%	29.48%	-61.29%	38.26%	-66.75%

REVENUE APPORTIONMENT (w/ fuel costs)
Test Year Ending December 31, 2024

	Present Revenue	CCOSS Responsibility	Increase without Design Change	Present Revenue as % of Cost	% Increase to Pay Cost	Proposed Revenue	Proposed $ Increase	Proposed % Increase
Residential	$364,900,135	$410,438,421	$399,762,917	88.9%	12.5%	$402,667,204	$37,767,069	10.3%
Commercial	$179,310,139	$181,246,050	$196,441,539	98.9%	1.1%	$194,167,156	$14,857,016	8.3%
Demand Billed	$19,846,908	$19,423,485	$21,743,094	102.2%	-2.1%	$21,381,911	$1,535,003	7.7%
Interruptible	$37,591,855	$35,455,226	$41,183,403	106.0%	-5.7%	$40,111,285	$2,519,430	6.7%
Transportation	$7,374,203	$7,305,141	$8,078,739	100.9%	-0.9%	$9,458,599	$2,084,396	28.3%
Generation	$8,783,222	$22,963,748	$9,622,377	38.2%	161.5%	$8,888,522	$105,299	1.2%
Total Retail	$617,806,462	$676,832,070	$676,832,069	91.3%	9.6%	$676,674,677	$58,868,215	9.5%
Other Revenues - Late Payment Revenue Increase							$157,392	
Total Increase	$617,806,462	$676,832,070	$676,832,069	91.3%	9.6%	$676,674,677	$59,025,607	9.6%

SUMMARY OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED REVENUES
Test Year Ending December 31, 2024

	Average	Dkt	Revenue		Increase	
	Customers	Sales	Present	Proposed	Amount	Percent
Firm Service						
Residential Firm	453,981	39,670,184	$364,900,135	$402,667,204	$37,767,069	10.3%
Small Commercial Firm	24,758	5,540,428	$46,549,945	$51,332,959	$4,783,014	10.3%
Large Commercial Firm	11,520	18,126,605	$132,760,194	$142,834,196	$10,074,002	7.6%
Small & Large Commercial Demand Billec	147	2,968,555	$19,846,908	$21,381,911	$1,535,003	7.7%
Total Firm Service	**490,405**	**66,305,772**	**$564,057,182**	**$618,216,271**	**$54,159,089**	**9.6%**
Interruptible Service						
Small Interruptible	156	1,243,581	$6,851,841	$7,237,176	$385,335	5.6%
Medium & Large Interruptible	79	6,759,531	$30,740,013	$32,874,109	$2,134,096	6.9%
Total Interruptible Service	**235**	**8,003,112**	**$37,591,855**	**$40,111,285**	**$2,519,430**	**6.7%**
Total Gas Sales	**490,640**	**74,308,884**	**$601,649,037**	**$658,327,556**	**$56,678,519**	**9.4%**
Transportation Service						
Total Transportation Service	**26**	**12,284,918**	**$7,374,203**	**$9,458,599**	**$2,084,396**	**28.3%**
Generation System	**5**	**215,753**	**$1,634,586**	**$1,649,399**	$14,812	0.9%
Generation Transportation	**4**	**31,969,107**	**$7,148,636**	**$7,239,123**	$90,487	1.3%
Total Retail*	**490,675**	**118,778,662**	**$617,806,462**	**$676,674,677**	**$58,868,215**	**9.5%**
*February 2021 Gas Event surcharges are not included.						
Other Gas Revenues						
Late Payment Revenue Increase				$157,392	$157,392	
Total Sales and Other Gas Revenues			**$617,806,462**	**$676,832,069**	**$59,025,607**	**9.6%**

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES

Test Year Ending December 31, 2024

Revenue by Rate Schedule

Residential Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	5,447,768		$9.00	$49,029,916	$11.00	$59,925,453	$10,895,537	
Distribution Charge		396,701,840	$0.274927	$109,064,047	$0.376599	$149,397,516	$40,333,469	
CIP Rider Roll In		396,701,840	$0.012722	$5,046,931	$0.000000	$0	($5,046,931)	
GUIC Rider Roll In		396,701,840	$0.021212	$8,415,006	$0.000000	$0	($8,415,006)	
Non-Fuel Subtotal				$171,555,900		$209,322,969	$37,767,069	22.0%
Gas Supply - Summer		96,944,295	$0.433904	$42,064,541	$0.433904	$42,064,541	$0	
Gas Supply - Winter		299,757,544	$0.504674	$151,279,694	$0.504674	$151,279,694	$0	
Gas Supply Subtotal		396,701,840		$193,344,235		$193,344,235	$0	0.0%
Average Customers	453,981		Total	$364,900,135		$402,667,204	$37,767,069	10.3%

Small Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	297,097		$20.00	$5,941,948	$30.00	$8,912,922	$2,970,974	
Distribution Charge		55,404,283	$0.219738	$12,174,426	$0.278538	$15,432,198	$3,257,772	
CIP Base (CCRC) Exemption		4,045	($0.023947)	($97)	($0.036669)	($148)	($51)	
CIP Rider Roll In		55,404,283	$0.012722	$704,866	$0.000000	$0	($704,866)	
CIP Rider Roll In Exemption		4,045	($0.012722)	($51)	$0.000000	$0	$51	
GUIC Rider Roll In		55,404,283	$0.013372	$740,866	$0.000000	$0	($740,866)	
Non-Fuel Subtotal				$19,561,958		$24,344,972	$4,783,014	24.5%
Gas Supply - Summer		12,754,331	$0.432632	$5,517,935	$0.432632	$5,517,935	$0	
Gas Supply - Winter		42,649,952	$0.503402	$21,470,052	$0.503402	$21,470,052	$0	
Gas Supply Subtotal		55,404,283		$26,987,987		$26,987,987	$0	0.0%
Average Customers	24,758		Total	$46,549,945		$51,332,959	$4,783,014	10.3%

Large Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	138,236		$50.00	$6,911,790	$50.00	$6,911,790	$0	
Distribution Charge		181,266,049	$0.184101	$33,371,261	$0.265771	$48,175,259	$14,803,998	
CIP Base (CCRC) Exemption		67,914	($0.023947)	($1,626)	($0.036669)	($2,490)	($864)	
CIP Rider Roll In		181,266,049	$0.012722	$2,306,108	$0.000000	$0	($2,306,108)	
CIP Rider Roll In Exemption		67,914	($0.012722)	($864)	$0.000000	$0	$864	
GUIC Rider Roll In		181,266,049	$0.013372	$2,423,888	$0.000000	$0	($2,423,888)	
Non-Fuel Subtotal				$45,010,557		$55,084,559	$10,074,002	22.4%
Gas Supply - Summer		49,456,119	$0.432632	$21,396,314	$0.432632	$21,396,314	$0	
Gas Supply - Winter		131,809,930	$0.503402	$66,353,324	$0.503402	$66,353,324	$0	
Gas Supply Subtotal		181,266,049		$87,749,638		$87,749,638	$0	0.0%
Average Customers	11,520		Total	$132,760,194		$142,834,196	$10,074,002	7.6%

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES
Test Year Ending December 31, 2024
Revenue by Rate Schedule

Small and Large Commercial Demand Billed

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,761			$467,364		$467,364	$0	
Distribution Demand Charge		3,462,474	$0.882000	$3,053,902	$0.932000	$3,227,026	$173,124	
Distribution Commodity Charge		29,685,548	$0.084775	$2,516,592	$0.145368	$4,315,329	$1,798,736	
CIP Base (CCRC) Exemption		274,475	($0.023947)	($6,573)	($0.036669)	($10,065)	($3,492)	
CIP Rider Roll In		29,685,548	$0.012722	$377,666	$0.000000	$0	($377,666)	
CIP Rider Roll In Exemption		274,475	($0.012722)	($3,492)	$0.000000	$0	$3,492	
GUIC Rider Roll In		29,685,548	$0.001994	$59,190	$0.000000	$0	($59,190)	
Non-Fuel Subtotal				$6,464,651		$7,999,654	$1,535,003	23.7%
Gas Supply Demand		3,462,474	$0.852050	$2,950,202	$0.852050	$2,950,202	$0	
Gas Supply Commodity		29,685,548	$0.351419	$10,432,055	$0.351419	$10,432,055	$0	
Gas Supply Subtotal				$13,382,257		$13,382,257	$0	0.0%
Average Customers	147		**Total**	$19,846,908		$21,381,911	$1,535,003	7.7%

Small Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,873		$150.00	$280,969	$170.00	$318,431	$37,463	
Distribution Charge - Tier I		6,217,904	$0.148846	$925,510	$0.205463	$1,277,549	$352,039	
Distribution Charge - Tier II		6,217,904	$0.148846	$925,510	$0.184917	$1,149,794	$224,284	
CIP Rider Roll In		12,435,808	$0.012722	$158,211	$0.000000	$0	($158,211)	
GUIC Rider Roll In		12,435,808	$0.005648	$70,240	$0.000000	$0	($70,240)	
Non-Fuel Subtotal				$2,360,440		$2,745,775	$385,335	16.3%
Gas Supply Charge		12,435,808	$0.361167	$4,491,401	$0.361167	$4,491,401	$0	0.0%
Average Customers	156		**Total**	$6,851,841		$7,237,176	$385,335	5.6%

Medium and Large Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	946			$289,126		$289,126	$0	
Distribution Charge - Tier I		33,797,655		$2,800,849		$4,725,025	$1,924,177	
Distribution Charge - Tier II		33,797,655		$2,800,849		$4,252,523	$1,451,674	
CIP Base (CCRC) Exemption		320,248	($0.023947)	($7,669)	($0.036669)	($11,743)	($4,074)	
CIP Rider Roll In		67,595,309	$0.012722	$859,963	$0.000000	$0	($859,963)	
CIP Rider Roll In Exemption		320,248	($0.012722)	($4,074)	$0.000000	$0	$4,074	
GUIC Rider Roll In		67,595,309	$0.005648	$381,792	$0.000000	$0	($381,792)	
Non-Fuel Subtotal				$7,120,836		$9,254,931	$2,134,096	30.0%
Gas Supply Charge		67,595,309		$23,619,178		$23,619,178	$0	0.0%
Average Customers	79		**Total**	$30,740,013		$32,874,109	$2,134,096	6.9%

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES

Test Year Ending December 31, 2024

Revenue by Rate Schedule

Transportation (summary of 26 customers)

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	312			$97,800		$97,800	$0	
Distribution Charge		122,849,184		$6,406,432		$9,272,253	$2,865,821	
Distribution Demand Charge		694,821		$612,832		$647,573	$34,741	
CIP Base (CCRC) Exemption		86,839,034		($566,089)		($866,833)	($300,744)	
CIP Rider Roll In		122,849,184		$1,562,915		$961,202	($601,714)	
CIP Rider Roll In Exemption		86,839,034		($1,104,786)		($804,042)	$300,744	
GUIC Rider Roll In		122,849,184		$365,099		$150,646	($214,453)	
Average Customers	26		**Total**	$7,374,203		$9,458,599	$2,084,396	28.3%

Generation (summary of 9 customers)

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	108			$31,200		$31,200	$0	
Distribution Charges		321,848,595		$7,277,776		$7,437,083	$159,307	
CIP Base (CCRC) Exemption		319,838,819		($70,029)		($107,232)	($37,204)	
CIP Rider Roll In		321,848,595		$4,094,631		$4,056,827	($37,804)	
CIP Rider Roll In Exemption		319,838,819		($4,069,062)		($4,031,858)	$37,204	
GUIC Rider Roll In		321,848,595		$659,188		$642,985	($16,203)	
Non-Fuel Subtotal				$7,923,704		$8,029,004	$105,299	1.3%
Gas Supply Charge				$859,518		$859,518	$0	0.0%
Average Customers	9		**Total**	$8,783,222		$8,888,522	$105,299	1.2%

Northern States Power Company
State of Minnesota Gas Jursidiction
PRESENT & PROPOSED RATES
Test Year Ending December 31, 2024

Docket No. G002/GR-23-413
Exhibit___(MMT-1), Schedule 6

PRESENT RATES	**Res**	**Sm Com**	**Lg Com**	**Sm Dmd**	**Lg Dmd**	**Sm Int**	**Med Int**	**Lg Int**	**Lg Fm Tran**	**Sm Int Tran**	**Med Int Tran**	**Lg Int Tran**
Customer Charge ($/Month	$9.00	$20.00	$50.00	$175.00	$275.00	$150.00	$300.00	$450.00	$300.00	$175.00	$325.00	$475.00
Distribution Charges ($/Therm)												
Commodity	$0.274927	$0.219738	$0.184101	$0.084775	$0.084775	$0.148846	$0.084775	$0.079765	$0.084775	$0.148846	$0.084775	$0.079765
Demand	N/A	N/A	N/A	$0.88200	$0.88200	N/A	N/A	N/A	$0.88200	N/A	N/A	N/A
Proposed Cost of Gas ($/Therm)												
Summer	$0.433904	$0.432632	$0.432632	$0.351419	$0.351419	$0.361167	$0.350956	$0.346915				
Winter	$0.504674	$0.503402	$0.503402	$0.852050	$0.852050	$0.361167	$0.350956	$0.346915				
Total Commodity Rate ($/Therm)												
Summer	$0.708831	$0.652370	$0.616733	$0.436194	$0.436194	$0.510013	$0.435731	$0.426680				
Winter	$0.779601	$0.723140	$0.687503	$1.734050	$1.734050	$0.510013	$0.435731	$0.426680				

PROPOSED RATES	**Res**	**Sm Com**	**Lg Com**	**Sm Dmd**	**Lg Dmd**	**Sm Int**	**Med Int**	**Lg Int**	**Lg Fm Tran**	**Sm Int Tran**	**Med Int Tran**	**Lg Int Tran**
Customer Charge ($/Month	$11.00	$30.00	$50.00	$175.00	$275.00	$170.00	$300.00	$450.00	$300.00	$195.00	$325.00	$475.00
Distribution Charges ($/Therm)												
Commodity	$0.376599	$0.278538	$0.265771	$0.145368	$0.145368	$0.205463	$0.145368	$0.130725	$0.145368	$0.205463	$0.145368	$0.130725
Commodity-Int Tier II						$0.184917	$0.130831	$0.117653				
Demand	N/A	N/A	N/A	$0.932000	$0.932000	N/A	N/A	N/A	$0.932000	N/A	N/A	N/A
Proposed Cost of Gas ($/Therm)												
Summer	$0.433904	$0.432632	$0.432632	$0.351419	$0.351419	$0.361167	$0.350956	$0.346915				
Winter	$0.504674	$0.503402	$0.503402	$0.852050	$0.852050	$0.361167	$0.350956	$0.346915				
Total Commodity Rate ($/Therm)												
Summer	$0.810503	$0.711170	$0.698403	$0.496787	$0.496787	$0.566630	$0.496324	$0.477640				
Winter	$0.881273	$0.781940	$0.769173	$1.784050	$1.784050	$0.566630	$0.496324	$0.477640				

EFFECT OF PROPOSED RATES with Fuel Costs
Test Year Ending December 31, 2024

REVENUE DEFICIENCY VS. PROPOSED RATES (w/ fuel)

Customer Class	Total Present Revenues	Revenue Deficiency Indicated by CCOSS	Total Effect Of Proposed Rates	Difference Between Revenue Deficiency and Proposed Rates
Residential	$364,900,135	$45,538,289 12.5%	$37,767,069 10.3%	$7,771,220 2.1%
Small Commercial	$46,549,945	$2,649,523 5.7%	$4,783,014 10.3%	($2,133,491) -4.6%
Large Commercial	$132,760,194	($713,610) -0.5%	$10,074,002 7.6%	($10,787,612) -8.1%
Small & Large Commercial Demand Billed	$19,846,908	($423,428) -2.1%	$1,535,003 7.7%	($1,958,432) -9.9%
Small Interruptible	$6,851,841	($973,110) -14.2%	$385,335 5.6%	($1,358,444) -19.8%
Medium & Large Interruptible	$30,740,013	($1,163,519) -3.8%	$2,134,096 6.9%	($3,297,615) -10.7%
Transportation	$7,374,203	($69,062) -0.9%	$2,084,396 28.3%	($2,153,458) -29.2%
Generation - System	$1,634,586	($441,618) -27.0%	$14,812 0.9%	($456,431) -27.9%
Generation - Transportation	$7,148,636	$14,622,143 204.5%	$90,487 1.3%	$14,531,656 203.3%
Other Revenues			$157,392 3.8%	($157,392) 3.8%
Total	$617,806,462	$59,025,608 9.6%	$59,025,607 9.6%	$1 0.0%

COMPARISON OF MONTHLY BILLS UNDER PRESENT AND PROPOSED RATES
Test Year Ending December 31, 2024

RESIDENTIAL FIRM SERVICE

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
10	$16.96	$19.64	$2.68	15.8%
20	$24.92	$28.28	$3.36	13.5%
30	$32.89	$36.92	$4.03	12.3%
40	$40.85	$45.56	$4.71	11.5%
50	$48.81	$54.20	$5.39	11.0%
73	$66.98	$73.91	$6.93	10.3%
100	$88.62	$97.40	$8.78	9.9%
200	$168.25	$183.80	$15.55	9.2%
300	$247.87	$270.19	$22.32	9.0%
500	$407.12	$442.99	$35.87	8.8%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$9.00	$11.00
Distribution Charge	$0.274927	$0.376599
Average Cost of Gas	$0.487380	$0.487380
Commodity Total	$0.762307	$0.863979
GUIC/CIP	$0.033935	$0.000000

SMALL COMMERCIAL FIRM SERVICE

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
50	$56.65	$68.28	$11.63	20.5%
100	$93.29	$106.56	$13.27	14.2%
200	$166.59	$183.13	$16.54	9.9%
186	$156.50	$172.59	$16.09	10.3%
250	$203.24	$221.41	$18.17	8.9%
350	$276.53	$297.98	$21.45	7.8%
500	$386.47	$412.82	$26.35	6.8%
750	$569.71	$604.24	$34.53	6.1%
1,000	$752.94	$795.65	$42.71	5.7%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$20.00	$30.00
Distribution Charge	$0.219738	$0.278538
Average Cost of Gas	$0.487110	$0.487110
Commodity Total	$0.706848	$0.765648
GUIC/CIP	$0.026094	$0.000000

LARGE COMMERCIAL FIRM GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
100	$119.43	$124.99	$5.56	4.7%
250	$223.57	$237.47	$13.90	6.2%
500	$397.14	$424.93	$27.79	7.0%
750	$570.71	$612.40	$41.69	7.3%
1,000	$744.29	$799.86	$55.57	7.5%
2,272	$1,627.57	$1,753.85	$126.28	7.8%
3,000	$2,132.86	$2,299.58	$166.72	7.8%
5,000	$3,521.43	$3,799.31	$277.88	7.9%
7,500	$5,257.14	$5,673.96	$416.82	7.9%
10,000	$6,992.85	$7,548.61	$555.76	7.9%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$50.00	$50.00
Distribution Charge	$0.184101	$0.265771
Average Cost of Gas	$0.484090	$0.484090
Commodity Total	$0.668191	$0.749861
GUIC/CIP	$0.026094	$0.000000

SMALL INTERRUPTIBLE GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
2,500	$1,470.96	$1,586.57	$115.61	7.9%
5,000	$2,791.92	$3,003.15	$211.23	7.6%
6,639	$3,657.97	$3,931.89	$273.92	7.5%
10,000	$5,433.83	$5,836.30	$402.47	7.4%
15,000	$8,075.75	$8,669.45	$593.70	7.4%
20,000	$10,717.66	$11,502.60	$784.94	7.3%
25,000	$13,359.58	$14,335.74	$976.16	7.3%
30,000	$16,001.50	$17,168.89	$1,167.39	7.3%
40,000	$21,285.33	$22,835.19	$1,549.86	7.3%
50,000	$26,569.16	$28,501.49	$1,932.33	7.3%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$150.00	$170.00
Distribution Charge	$0.148846	$0.205463
Cost of Gas	$0.361167	$0.361167
Commodity Total	$0.510013	$0.566630
GUIC/CIP	$0.018370	$0.000000

COMPARISON OF MONTHLY BILLS UNDER PRESENT AND PROPOSED RATES
Test Year Ending December 31, 2024

MEDIUM INTERRUPTIBLE GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
5,000	$2,570.51	$2,781.62	$211.11	8.2%
10,000	$4,841.02	$5,263.24	$422.22	8.7%
20,000	$9,382.03	$10,226.48	$844.45	9.0%
30,000	$13,923.05	$15,189.73	$1,266.68	9.1%
40,000	$18,464.06	$20,152.97	$1,688.91	9.1%
46,065	$21,218.09	$23,163.06	$1,944.97	9.2%
60,000	$27,546.10	$30,079.45	$2,533.35	9.2%
70,000	$32,087.11	$35,042.69	$2,955.58	9.2%
80,000	$36,628.13	$40,005.93	$3,377.80	9.2%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$300.00	$300.00
Distribution Charge	$0.084775	$0.145368
Cost of Gas	$0.350956	$0.350956
Commodity Total	$0.435731	$0.496324
GUIC/CIP	$0.018370	$0.000000

LARGE INTERRUPTIBLE GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
50,000	$22,702.51	$24,331.99	$1,629.48	7.2%
100,000	$44,955.02	$48,213.98	$3,258.96	7.2%
200,000	$89,460.04	$95,977.96	$6,517.92	7.3%
300,000	$133,965.07	$143,741.94	$9,776.87	7.3%
400,000	$178,470.09	$191,505.92	$13,035.83	7.3%
713,546	$318,013.67	$341,267.81	$23,254.14	7.3%
500,000	$222,975.11	$239,269.89	$16,294.78	7.3%
600,000	$267,480.13	$287,033.87	$19,553.74	7.3%
700,000	$311,985.16	$334,797.85	$22,812.69	7.3%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$450.00	$450.00
Distribution Charge	$0.079765	$0.130725
Cost of Gas	$0.346915	$0.346915
Commodity Total	$0.426680	$0.477640
GUIC/CIP	$0.018370	$0.000000

Summary List of 2024 Tariff Changes

Tariff	Sheet No.	Rate Code	Changes
Table of Contents	1-1		1. Removed "Small Volume Flex Interruptible Service of Customer Owned Gas (closed)".
Index of Company's Service Area	3-1, 3-1.1, 3-2, 3-2.1, 3-3		Service area updates.
Tables of Contents	5-TOC		1. Removed "Small Volume Flex Interruptible Service of Customer Owned Gas (closed)".
Residential Firm Service	5-1	101	1. Rate changes. 2. Proposed new Base Cost of Gas rates.
Commercial Firm Service	5-2	Small: 102, 108 Large: 118, 125	1. Rate changes. 2. Proposed new Base Cost of Gas rates.
Commercial Demand Billed Service	5-3, 5-4	Small: 119 Large: 103	1. Rate changes. 2. Edited "Revenue Decoupling Mechanism Rider" language. 3. Proposed new Base Cost of Gas rates.
Large Firm Transportation Service	5-5, 5-6	104	1. Rate changes. 2. Added "Revenue Decoupling Mechanism Rider".
Interruptible Service	5-10, 5-10.1, 5-11, 5-11.1, 5-12, 5-13	Small: 105, 111, XXX Medium: 106, YYY Large: 120, ZZZ	1. Rate changes. 2. Split "Interruptible Service" into two Tiers with new rates and rate codes proposed. 3. Interruptible customers agree that they may be subject to extraordinary economic events. 4. Edited "Revenue Decoupling Mechanism Rider" language. 5. Proposed new Base Cost of Gas rates.
Interruptible Transportation Service	5-16, 5-17, 5-17.1	Small: 123 Medium: 107 Large: 124	1. Rate changes. 2. Added "Revenue Decoupling Mechanism Rider".
Negotiated Transportation Service	5-24	114	1. Rate changes.
Small Volume Flex Interruptible Transportation of Customer Owned Gas	5-29, 5-30, 5-31, 5-32, 5-33	157	1. Canceled service.

Summary List of 2024 Tariff Changes

Tariff	Sheet No.	Rate Code	Changes
Purchased Gas Adjustment Clause	5-41		1. Proposed new Base Cost of Gas rates.
Revenue Decoupling Mechanism Rider	5-71, 5-72		1. Added all services, except "Negotiated Transportation Service", to being applicable to adjustments in the "Revenue Decoupling Mechanism Rider". 2. Edited language stating that separate deferrals will be calculated for each class.
General Rules and Regulations	6-16.2		1. Added language on Delivery Pressure and clarified Customer responsibilities relating to Maintenance, Relocation, and Abandonment.
Residential Service Agreement	7-2, 7-3		1. Added space for phone numbers. 2. Clarified Installation Requirements and responsibilities of Xcel Energy. 3. Clarified Customer responsibilities relating to Maintenance, Relocation, and Abandonment.
Commercial & Industrial Service Agreement	7-6, 7-7.1		1. Clarified Customer responsibilities and Installation Requirements. 2. Removed incorrectly placed dollar signs.
Interruptible Gas Service Agreement	7-10, 7-11, 7-11.1		1. Added language relating to new Tier I & Tier II Interruptible services. 2. Added that Late Payment Charges may be added to overdue bills.
Gas Main Refundable Deposit Agreement	7-38, 7-40		1. Added language to clarify Xcel Energy's rights and responsibilities in providing service. 2. Modified Xcel Energy's signatory section.
Minimum Burn Agreement	7-42		1. Modified Xcel Energy's signatory section.

END USER ALLOCATION SERVICE: COST STUDY

Number of EUAS Customers as of September 2021

(1)	(2)				(3)	(4)	(5) = (3)*(4)	(6)=(5)/12	(7)	(8)=(6)/(7)
Category	**Employee**	**Salary t**	**Labor Loading**	**Annual Work Hours**	**Loaded Hourly Rate**	**Annual EUAS Hours**	**Annual Labor**	**Monthly Labor**	**Customers**	**Monthly Cost / Customer**
Operational Labor	Principal Analyst	$118,000	166.36%	2,080	$94.38	**48**	$4,530.24	$377.52	**8**	$47.19
Regulatory Exp *	Associate Analyst	$90,000	166.36%	2,080	$71.98	**12**	$863.76	$71.98	**8**	$9.00
Regulatory Exp **	Management / Legal	$157,000	166.36%	2,080	$125.57	**3**	$376.71	$31.39	**8**	$3.92
Total										**$60.11**

* Estimated staff hours required for development and monitoring of compliance filings.

** Estimated mgmt/legal hours required for compliance filing.

FREQUENCY DISTRIBUTION

Comparison of Residential LIHEAP customers vs. all Non-LIHEAP Residential customers
2022 annual usage