Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

August 1, 2025

—Via Electronic Filing—

Mike Bull
Acting Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. E002/M-25-67

Dear Mr. Bull:

Enclosed is the Petition for approval of changes in Contract Demand Entitlements of Northern States Power Company, doing business as Xcel Energy, pursuant to Minn. Rule 7825.2910, Subp. 2.

Portions of our filing contain trade secret information as defined under Minn. Stat. § 13.37. As such, this data is protected from public disclosure and has been marked accordingly. Xcel Energy makes extensive efforts to maintain the secrecy of this information. This information is not available outside the Company except to other parties involved in contracts and to regulatory agencies under the confidentiality provisions of state or federal law, as evidenced by the non-disclosure provisions in the contracts. Xcel Energy also provides this information to state regulatory agencies in the Annual Automatic Adjustment of Charges Reports and in the monthly purchased gas adjustment (PGA) filings in the confidential trade secret versions of these reports.

The supply information has economic value to Xcel Energy, its customers, suppliers, and competitors in at least three ways. If suppliers know the terms of Xcel Energy's supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. Suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Competitors of Xcel Energy such as other LDCs also purchase their services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may offer slightly better prices to suppliers, denying Xcel Energy's access to this gas or other services.

Any of these results would harm Xcel Energy and its natural gas customers. Because Xcel Energy competes for supplies, transportation, storage, and other services in the wholesale market, disclosure would directly harm Xcel Energy by making its delivered supply cost less competitive. To the extent that Xcel Energy supply costs rise, Xcel Energy's regulated sales customers would have to pay higher natural gas rates. This result would not serve the public interest.

Attached to this cover letter, we provide the required information as specified in Minn. Rules 7829.1300 and 7829.0700, including to whom information requests should be directed.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists. Please contact me at (612) 330-7681 or lisa.r.peterson@xcelenergy.com or Paget Pengelly at (612) 330-6892 or paget.j.pengelly@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
cc: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. Rule 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, Subd. 3, Xcel Energy has electronically filed this document. In compliance with Minn. Rule 7825.2910, Subp. 3, Xcel Energy has served a summary of this Petition on the interveners in the two most recent (2023 and 2021) general rate case filings for the Company's natural gas utility operation. The Summary has also been served on all parties on Xcel Energy's miscellaneous gas service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. Rule 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Riley Conlin
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 216-9309

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on August 1, 2025. The Company requests Commission approval to implement the rate impact of this filing in our PGA effective with November 1, 2025 usage. Pursuant to Minn. Stat. § 216B.16, Subd. 7, Minn. Rule 7825.2920, and our PGA tariff (Minnesota Gas Rate Book Sheet Nos. 5-40, 5-41, and 5-42), Xcel Energy will provisionally place the PGA changes into effect on November 1, 2025, subject to later Commission approval.

D. Statute Controlling Schedule for Processing the Filing

The applicable statute is Minn. Stat. § 216B.16, Subd. 7. This statute does not state a specific timeframe for Commission action. The applicable rules are Minn. Rule 7825.2910, Subp. 2, 7825.2920, 7829.1300, and 7929.1400. Under Minn. Rule 7829.0100, Subp. 11, the Commission treats all filings that do not fall into a specific category as Miscellaneous Filings. Minn. Rule 7829.1400, Subpts. 1 and 4, permit comments in response to a miscellaneous filing within 30 days of filing, with reply comments 10 days thereafter.

E. Utility Employee Responsible for Filing

Lisa Peterson
Director, Regulatory Pricing and Analysis
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. Rule 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

Riley Conlin
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
riley.conlin@xcelenergy.com

Christine Schwartz
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Schwartz at the Regulatory Records email address above.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-25-67

PETITION

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition for approval of a change in Contract Demand Entitlements, pursuant to Minn. Stat. § 216B.16, Subd. 7 and Minn. Rule 7825.2910, Subp. 2. This Petition seeks approval from the Commission to allow the Company to implement, through the Purchased Gas Adjustment (PGA), changes in our interstate pipeline transportation, storage entitlements, and other demand-related contracts for the upcoming year.

In accordance with the Minnesota Department of Commerce (Department or DOC) Comments in Docket No. G002/M-19-498, the Company is including two periods of entitlement costs with this filing as a result of a proposed rate increase on one interstate pipeline for new rates to become effective January 1, 2026. The first period shows annual costs effective November 1, 2025, and includes prospective interstate pipeline rate changes from two pipelines which will be effective August 1, 2025, subject to refund, but does not include the prospective rate increases of the third pipeline effective January 1, 2026. The second period includes all three interstate pipeline rate increases to be effective as of January 1, 2026, subject to refund. We have projected an increase in Minnesota design day (DD) requirements of 6,500 Dekatherms (Dth), with an increase in demand-related costs to Minnesota for the 2025-2026 year of approximately $7,081,822 (8.2 percent) effective November 1 and approximately $16,006,557 (18.4 percent) effective January 1, 2026 as compared to the previous year. The change in costs is caused primarily by FERC rate cases filings by three interstate pipeline transportation providers. The Company has intervened in all three cases and will be an active participant in each rate case on behalf of our customers to ensure just and reasonable rates. Annually updating our natural gas transportation, storage entitlements, and supply contracts is important to ensure the Company has access to sufficient capacity to cover the anticipated peak demand of our natural gas customers.

The Company respectfully requests approval to implement our 2025-2026 Heating Season Supply Plan effective November 1, 2025, for customers served with natural gas in the State of Minnesota. Pursuant to Minn. Rule 7825.2920 and prior Commission practice, we will provisionally implement the PGA rate changes associated with this filing on November 1, 2025, with the additional increase on January 1, 2026.

The following attachments are included with this Petition:

- Attachment 1: Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2 and the requirement from the February 17, 2023 Order.[1]
- Attachment 2: Information Provided in Response to the Department Letter Dated October 1, 1993 and Storage Entitlements required by Order dated October 16, 2015 in Docket No. G002/M-14-654.
- Attachment 3: Information Provided in Response to Report Requirements in Docket No. G002/M-08-46 and Orders dated April 22, 2016 in Docket No. G002/M-16-88 and February 12, 2020 in Docket No. G002/M-19-703 regarding use of financial instruments to limit price volatility.

I. DESCRIPTION AND PURPOSE OF FILING

This filing seeks Commission approval to allow the Company to implement, through the PGA, changes in our interstate pipeline transportation, storage entitlements, and other demand-related contracts for the upcoming year. Updating our natural gas transportation, storage entitlements, and supply contracts on an annual basis is important to ensuring the Company has access to sufficient capacity to cover the anticipated peak demand of our natural gas customers. To determine the amount required, we consider our forecast of customer needs under DD conditions. By comparing that anticipated need to our current supply arrangements and peaking plant availability, we can determine what incremental additions are needed to ensure

[1] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers*, Docket Nos. G999/CI-21-135, G008/M-21-138, G004/M-21-235, G002/CI-21-610, and G011/CI-21-611, ORDER REQUIRING ACTIONS TO MITIGATE IMPACTS FROM FUTURE NATURAL GAS PRICE SPIKES, SETTING FILING REQUIREMENTS, AND INITIATING A PROCEEDING TO ESTABLISH A GAS RESOURCE PLANNING REQUIREMENTS (February 17, 2023), Order Point 9.

we can meet our customer needs under the most extreme conditions at reasonable cost.

Pursuant to Minn. Rule 7825.2920 and prior Commission practice, we will provisionally implement the PGA rate changes associated with this filing on November 1, 2025, and respectfully request Commission approval of the revised entitlements effective on November 1, 2025. We list the changes reflected in this filing below.

A. Change in Design Day

Our filing reflects a change in our DD forecast from the 2024-2025 heating season, as described in Attachment 1, page 3. Our forecasted firm customer count in the Minnesota State jurisdiction increased by 3,295 customers (primarily residential customer growth), from 493,513 forecast for the 2024-2025 heating season to 496,808 forecast for the 2025-2026 heating season. This projection contributes to an increase in DD requirements in Minnesota State jurisdiction of 1,951 Dth, from 784,381 to 786,332.

B. Change in Resources to meet Design Day

Reflected in this filing are minor changes in our resources used to meet our DD customer requirements, including entitlements on our pipeline and storage supplier systems: Northern Natural Gas Company, Viking Gas Transmission Company, Great Lakes Gas Transmission Company, ANR Pipeline Company, WBI Energy Transmission, and ANR Storage Company. Depending on the service, these changes take effect at various times during the heating season.

Attachment 1 and Attachment 2 provide background information regarding each of these proposed changes. Specifically, Attachment 1 contains the following documentation required by Minn. Rule 7825.2910, Subp. 2:

- a description of the factors contributing to the need for changing demand;
- the Company's DD demand by customer class and the change in DD demand, if any, necessitating the demand revision;
- a summary of the levels of winter versus summer usage for all customer classes; and
- a description of DD gas supply from all sources under the new level, allocation, or form of demand.

The information provided in Attachment 2 is in response to the October 1, 1993 letter from the Department and the October 16, 2015 Order of the Commission[2], and outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, pipeline billing units and storage entitlements from the 2024-2025 entitlement levels.

C. Change in Jurisdictional Allocations

The changes in the DD forecast slightly alter the allocation of entitlements between the Minnesota and North Dakota retail natural gas jurisdictions. This filing updates this allocation to reflect the latest DD forecast with slight increases in contract demand requirements and customer growth in North Dakota. As a result the DD allocation factor decreased slightly for the Minnesota State jurisdiction from 86.42 percent to 86.02 percent.

D. Change in Supply Reservation Fees

This filing also reflects updated costs for firm gas supply reservation fees. These are demand charges paid for contracted delivered supply deals rather than for pipeline transportation service. The decrease in the amount of contracted delivered supply, as well as increases in fees from providers have resulted in an increase in supplier reservation charges of $412,627.

E. Heating Season Plan for Use of Financial Instruments

Attachment 3 provides information in response to the reporting requirements established in Docket No. G002/M-12-519 (Order dated September 23, 2013) regarding our use of financial instruments to limit first-of-the-month commodity price volatility, and Docket Nos. G002/M-16-88 and G002/M-19-703 (Orders dated April 22, 2016 and February 12, 2020) regarding benefits to customers. The Company's hedging practices are consistent with prior Commission Orders and the attachment discusses the anticipated benefits of the contracts to ratepayers and shows a summary of hedge transactions to date for the 2025-2026 heating season.

F. Reserve Margin Information

We propose a capacity reserve margin of 6.2 percent for the 2025-2026 heating season, as discussed in Attachment 1, Section C and Attachment 2, Schedule 1, Page 3 of 3.

---

[2] Docket No. G002/M-14-654.

G. Information Provided in Attachments

Xcel Energy has endeavored to provide all requested information, and has taken steps to ensure the filing's accuracy so that this Petition contains the necessary information for approval of the changes in Contract Demand Entitlements. The location of specific types of information is detailed in the list of attachments below.

Attachment 1: Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2 and Information Provided in Response to Commission Order dated February 17, 2023 in Docket Nos. G999/CI-21-135, G008/M-21-138, G004/M-21-235, G002/CI-21-610, and G011/CI-21-611.

Schedule	Title
1	Derivation of Minnesota Jurisdiction Allocation Factor
2	Demand Cost of Gas Impact
3, page 1	Summary of Design Day Demand by Customer Class
3, page 2	Derivation of Actual Peak Day Use Per Customer
4	Historical Sales – Seasonal Usage
5	Firm Supply Entitlements

Attachment 2: Information Provided in Response to the Department Letter dated October 1, 1993 and Commission Order dated October 16, 2015 in Docket No. G002/M-14-654.

Schedule	Title
1, page 1-2	Demand Profile, Storage Entitlements
1, page 3	Changes to Contract Entitlements
2, page 1-3	Rate Impact
2, page 4	Derivation of Current PGA Costs

Attachment 3: Information Provided in Response to Report Requirements in Docket No. G002/M-08-46 Regarding Use of Financial Instruments to Limit Price Volatility, and Docket Nos. G002/M-16-88 and G002/M-19-703 (Orders dated April 22, 2016 and February 12, 2020) regarding benefits to customers.

Schedule	Title
1	Summary of Hedge Transactions

II. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

As calculated in Attachment 1, Schedule 2, page 1 of 2, the effect of the proposed changes in demand cost upon Xcel Energy's Minnesota State annual revenue is an increase of $7,172,981 or about 8.2 percent effective November 1, 2025 and $16,006,557 or about 18.4 percent of the total Minnesota State demand costs effective January 1, 2026 as compared to the previous year's CD Entitlement filing. The change in costs is predominantly the result of proposed rate increases on three interstate pipeline transportation and storage providers. The Company is an active participant in each of these federal rate cases to protect Minnesota interests. The cost change will automatically be reflected in rates through the operation of the Company's PGA clause. The demand rate calculation is shown in Attachment 2, Schedule 2, page 4 of 4.

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2025-2026 Heating Season Supply Plan effective November 1, 2025, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2025 usage. Approval will enable us to provide continued reliable and competitive service for our natural gas customers in Minnesota. The Company will provisionally reflect the change in entitlement costs associated with the revised contract demand entitlements in the Company's November PGA, subject to later Commission approval.

Dated: August 1, 2025

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF CHANGE IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-25-67

PETITION

SUMMARY OF FILING

Please take notice that on August 1, 2025, Northern States Power Company, doing business as Xcel Energy, filed a Request for Change in Contract Demand Entitlements pursuant to Minn. Rule 7825.2910, Subp. 2. Xcel Energy requests Commission approval to implement its 2025-2026 Heating Season Supply Plan effective November 1, 2025. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2025, subject to later Commission approval.

ATTACHMENT 1

Northern States Power Company

Filing Upon Change in Demand
Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2

Northern States Power Company

Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2
Filing Upon Change in Demand

A. Description of the factors contributing to the need for change in demand

As discussed in our Petition, the factors contributing to the need for a change in demand include:

- Increase in design day (DD) requirements,
- Changes in resources required to meet the DD and provide an adequate reserve margin,
- Updates to jurisdictional allocations, and
- Changes in supply reservation fees.

We discuss each of these factors below.

1. Change in Design Day

Our objective in calculating DD customer demand is to forecast anticipated demand at design temperatures, so that adequate firm supply resources may be planned for and made available if DD weather conditions occur. We recognize that customer response to temperature is dynamic, particularly if we experience severely cold seasonal temperatures. Therefore, we continue to: (1) calculate DD using both Actual Peak Use per Customer Design Day (UPC DD) and Average Monthly Design Day (Avg. Monthly DD) methods; and (2) consider the results when predicting future DD needs.

In the Company's 2004-2005 Contract Demand Entitlements filing, the Company described its addition of a second methodology for calculating our DD, the UPC DD.[1] The addition of UPC DD ensures that the DD is adequately and accurately estimated. Prior to the 2004-2005 Docket, we used a single methodology, based on a linear regression calculation of average monthly weather and usage data.

Our forecasted firm customer count in Minnesota State increased by 3,295 customers, from 493,513 forecast for the 2024-2025 heating season to 496,808 forecast for the 2025-2026 heating season. This projection contributes to an increase in DD

[1] Docket No. G002/M-04-1735.

requirements in Minnesota State of 1,951 Dekatherms (Dth), from 784,381 to 786,332, using the UPC DD method as detailed on **Attachment 1, Schedule 3, page 1 of 2**.

a. Average Monthly Design Day

We use the Avg. Monthly DD to develop the allocations by state and by service region as shown on **Attachment 1, Schedule 1, page 1 of 5**. The Avg. Monthly DD calculation is based on linear regression using 62 data points, from January 2020-February 2025, as shown on **Attachment 1, Schedule 1, pages 2-5**. Nearly 89 percent of all regression statistics were very strong with R-squared values at or above 80 percent.[2] The regions with R-squared values below 80 percent were generally those with much lower customer counts.

In performing the regression analysis above, similar to previous years, one area (Grand Forks MN Small Commercial (GFMSC), resulted in a negative intercept coefficient. This would indicate negative gas use at zero heating degree day (HDD), which is not realistically possible. To correct this, we adjusted the heating degree day values to zero for each summer month for the affected area. This supports our base use of gas during the summer months, which is not temperature dependent, and is more reflective of reality. We then performed the regression analysis on the one area, which resulted in positive intercept coefficients, though not statistically significantly different from zero.

Additionally, we tested each regional demand area and class regression for the presence of autocorrelation, as the Department requested in Docket No. G002/M-17-586. For each regression analysis in the Avg. Monthly DD model we calculated the Durbin-Watson statistic, a common measure for the presence of autocorrelation. Consistent with other statistics and expectations, the most independent errors existed for residential customer regions, while those most prone to autocorrelation were small commercial classes. There were two Durbin-Watson results over 2, and five regressions with values below 1, indicating positive autocorrelation. In other words, the previous error predicted the following error term.

To address the autocorrelation bias present in these regression models, the Company employed a two-stage regression model, whereby the original data values were transformed and lagged by one timespan with the estimate of the autocorrelation effect. The regression analysis is then performed on the transformed data. In the

[2] The closer its R-squared value is to 100 percent or "1", the greater the ability of that model to predict a trend.

event the results remain autocorrelated (with Durbin-Watson statistics above 2 or below 1), the process was repeated. One region went through this process three times, and one twice. In all cases the autocorrelation was corrected with new Durbin-Watson statistics between 1 and 2. The values of the regression results are displayed in **Attachment 1, Schedule 1, pages 2-5.**

Given the robust regression statistics, we believe the Avg. Monthly DD method accurately captures the DD relationship between the states and service regions and produces the appropriate allocations by state and service region according to current customer use trends.

b. Actual Peak Use Per Firm Customer

The actual use per firm customer data contains the daily total usage for firm customers that do not have individual actual peak day information. As detailed in **Attachment 1, Schedule 3, page 2 of 2,** the actual peak day use per firm customer remains the same at 1.57393 Dth as experienced January 29, 2004. For non-demand-billed customers, the projected DD is calculated as the sum of the Avg. Monthly DD totals for all service regions to yield the Projected DD for these Minnesota State customers of 757,793 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 28,540 Dth is added to the DD estimate for the Residential, Small and Large Commercial classes to determine the total Minnesota State DD Projection of 786,332 Dth as shown on **Attachment 1, Schedule 3, page 1 of 2**.

We continue to maintain and compare both methodologies. We believe that the models are adequately estimating natural gas needs during cold weather and the current use per customer estimate should be maintained. However, we continue to evaluate the models each year to determine if they are adequately projecting natural gas supply needs and adjust the use per customer estimate if necessary.

2. *Change in Resources to Meet Design Day*

Attachment 2, Schedule 1, pages 1-2 details the demand entitlement changes to meet the increased DD in Minnesota State for the 2025-2026 heating season compared to the 2024-2025 heating season as filed in Docket No. G002/M-24-271. **Attachment 1, Schedule 2** details the demand cost component changes for the 2025-2026 heating season. The projected DD for the Company increased by 6,500 Dth/day (1,951 Dth/day for Minnesota) for the 2025-2026 heating season. The demand entitlement changes discussed below represent new and incremental contracts to serve the growth in projected DD. In accordance with the Minnesota Department of Commerce (Department or DOC) Comments in Docket No. G002/M-19-498, the

Company is including two versions of **Attachment 1, Schedule 2.** The first representing costs effective November 1, 2025, the second representing costs effective January 1, 2026, following the implementation, subject to refund of increased rates in Northern Natural Gas' FERC rate case. **Attachment 1, Schedule 2, page 2 of 2** also shows the year-to-year demand cost changes allocated by jurisdiction or upstream/system supply. The schedule shows an increase of demand related total costs of approximately $8,338,414 ($7,172,981 for Minnesota) effective November 1, 2025, and an increase of $18,607,229 ($16,006,557 for Minnesota) including contract demand and supplier entitlement changes. This increase is due primarily to three FERC rate cases on ANR Pipeline Company (ANR), Great Lakes Gas Transmission (GLGT), and Northern Natural Gas (NNG) pipelines and newly acquired entitlements to continue to meet DD.

a. Change in Northern Natural Gas (NNG) entitlement (effective November 1, 2025)

As part of NNG's Northern Lights 2025 (NL25) expansion project, NSP has contracted to acquire an additional 24,033 Dth/day of firm entitlement to be effective November 1, 2025 to meet growing demand. Of the total, 18,782 Dth/day on a year-round basis, is significantly discounted as part of NSP's existing long term discount agreement with NNG, and provides for growth in St. Cloud, MN and the surrounding areas. The remaining 5,251 Dth/day will serve growth areas around Delano, MN and St. Michael, MN at NNG's maximum tariff rate and will provide NSP with capacity to meet future design day requirements. The discounted capacity (18,782 Dth/day) is for a term ending October 31, 2027 and the tariff rate portion (5,251 Dth/day) is for a term of 10 years from November 1, 2025. Annual costs are $629,532 per year and are included in **Attachment 1, Schedule 1, pages 1 and 2.**

b. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2025)

As has been a historical practice, NSP requires short-term capacity on Viking or delivered supply to address a small portion of our overall DD projections. Viking continues to be sold out on a forward haul basis, making delivered supply a cost-effective short-term alternative. For the 2025-2026 heating season, NSP plans to acquire a total of 4,000 Dth/day of delivered from a producer/marketer on Viking for November through March to meet seasonal peaking needs. Delivered supply typically is priced in two parts, a demand fee for a right to call on the capacity delivered to the city-gate, and a commodity for the physical gas. The demand cost for this transaction is currently estimated at the Viking maximum tariff rate and included in the supply reservation fees section at a total cost of $121,766.

c. Change in ANR Pipeline entitlement (effective April 1, 2025)

Small increases were made to entitlement holdings on ANR Pipeline pursuant to ANR Pipeline's tariff. These are annual adjustments to match the changes in ANR's in-kind fuel percentages made each spring by the Federal Energy Regulatory Commission (FERC). These volume changes maintain our delivery quantities in response to changes in fuel requirements and do not materially impact demand costs.

d. Storage and Financial Hedging Options

Following the extraordinary gas prices and supply disruptions experienced during Winter Storm Uri in 2021 NSP continues to explore options to reduce the potential impact of such dramatic price swings on our customers. These include exploring options to add storage capacity to our current storage agreements. Additional storage would reduce gas purchases priced at the daily gas price, provide reliability of supplies, and, depending on the location, provide increased regional diversity.

On April 21, 2025 WBI posted an notice of binding open season for its Baker Storage Enhancement Project. The project is proposed to create up to 72,000 Dth/day of additional withdrawal capacity from WBI's storage field, with 1.0 bcf dth in associated storage capacity for service estimated to begin in 2029. NSP currently holds firm transportation on WBI's integrated pipeline system, which could connect with the storage project. In evaluating the proposal, NSP determined that the potential storage service would provide reliable gas supplies throughout the winter heating season at a known price, increasing our quantity of gas supplies from storage on a design day, and provide additional protection against extreme price spikes like those seen during Winter Storm Uri. As such, NSP bid into this open season offering on May 20, 2025. WBI is currently evaluating bids.

The Company also continues to survey the market for financial hedging products that would protect against daily price swings. As part of its currently effective hedge plan filed in Docket No. G002/M-23-521, the Company obtained approval to use swap agreement contracts as a new financial hedge tool and will be surveying the market for effective products. The Company successfully implemented these new hedge tools during the previous season, and while no extraordinary price spikes occurred, we believe these financial products to be a valuable tool in mitigating extreme price impacts for our customers. The Company will continue to update the Commission on progress in this area.

e. Storage Alternatives

On February 21, 2024, in Docket No. G002/M-24-80, the Department of Commerce provided Comments on the Company's petition for approval of a three-year rule variance to the PGA Rules to allow recovery of a storage-related cost of natural gas—the 2025-2027 property tax on the Company's natural gas for use for its retail natural gas customers stored in the state of Kansas—through the PGA. In its Kansas Property Tax Rule Variance filings, the Company historically provided a discussion of the storage alternatives examined and our efforts to obtain the most cost-effective storage options. In its April 2, 2024 Order, the Commission agreed with and adopted the recommendations of the Department of Commerce. The Department recommended that the Company provide an updated analysis in its future Demand Entitlement filings.

To ensure the most cost-effective storage service for our customers, we consider the following factors when evaluating service options: reservation costs (capacity and deliverability); transportation to our service area; flexibility of services, and whether storage and transportation capacity is available for purchase In May 2026, a portion of our NNG storage portfolio is up for renewal, with service expiring in May 2027 (6,529,975 Dths out of 12,585,000 Dths or roughly 52 percent). The agreement has a twelve-month notification provision for renewal. In accordance with the analysis below, we expect to renew the agreement for the guaranteed four-year term, at the required time.

Table 1
Future Storage Contracts

Contract	Capacity	Deliverability	End Date	Renewal Date	% of Portfolio
22337	6,529,975	113,259	5/31/2027	5/31/2026	52%
22337	155,000	2,689	5/31/2027	11/30/2026	1%
112399	4,500,000	78,050	5/31/2027	11/30/2026	36%
22337	1,400,000	24,282	5/31/2028	11/30/2027	11%
Total Portfolio	**12,584,975**	**218,280**			100%

In general, interstate storage and transportation capacity continue to be fully subscribed (sold-out) near our service areas. Since supply and demand dynamics favor suppliers at this time, we are unable to demand discounts or other creative commercial arrangements from NNG regarding our Kansas storage contract entitlements. NNG can simply sell our capacity to another willing buyer at maximum rates if we do not want to pay those rates or demand special arrangements not required by NNG's tariff.

While more distant storage providers may offer available storage capacity, two factors militate against contracting for that more distant capacity. First, ANR Storage (ANRS), Natural Gas Pipeline Company (NGPL), and ANR Pipeline (ANRP) does not have storage capacity similar to that being renewed on NNG available today or offer a similar service. Further, the transportation capacity needed on upstream pipelines to move the gas from those storage fields to our service areas is typically fully subscribed. For example, ANRP's transportation facilities and ANR Storage, connected through Great Lakes Gas Transmission, would require expansion of their mainline facilities to provide more service to NNG interconnects and on to our service areas. Second, even if capacity were available, the cost of transporting the gas from a more distant storage field to our service areas through one or more additional pipelines would exceed the cost of using NNG's storage including the associated Kansas tax obligation.

To illustrate this point, Table 2 below details a cost comparison using each company's current or proposed maximum tariff rates for our storage alternatives including the requisite transportation service to move to our service areas at this time. For purposes of this illustration, we ignored the additional cost of any expansions required by these transporters to create the capacity to serve us.

Table 2: Storage Alternatives Analysis

Capacity:	6,529,975	Dth			
Deliverability:	113,259	Dth/d			
Storage Provider:	Capacity Rate:	Deliverability Rate:	Transport Rate:		
	$/Dth/yr	$/Dth/mth	$/Dth/mth		
NNG	$ 0.99910	$ 4.80030	$ -	No new transport necessary	
ANRP	$ 0.79530	$ 1.69640	$ 10.48680	Transport to VGT on ANRP	
ANRS**	$ 0.06000	$ 3.46450	$ 9.12200	Transport to Carlton on Great Lakes	
NGPL	N/A	$ 4.70000	$ 47.70000	New Transport to Service Area	
Storage Provider:	Capacity Cost	Deliverability Cost	Transport Cost	Kansas Tax*:	**Total Annual Cost:**
NNG	$ 6,524,098	$ 6,524,126	$ -	$ 361,155	**$ 13,409,379**
ANRS	$ 4,701,582	$ 4,708,630	$ 7,114,178	$ -	**$ 16,524,389**
ANRP	$ 5,193,289	$ 2,305,591	$ 8,178,575	$ -	**$ 15,677,455**
NGPL	$ -	$ 6,387,808	$ 27,012,272	$ -	**$ 33,400,079**

*Kansas tax shown is the pro-rata allocation of the contracted volume.
**ANRS capacity rate is monthly and market based.

Currently, NNG, ANRP and Great Lakes have filed rate cases at FERC proposing new rate to be in effect during the renewal period. As such, Table 2 includes all current or proposed tariff maximum reservation costs, and Kansas tax, for NNG and alternative storage options. ANRS and ANRP both have storage fields in Michigan. Both fields do not currently have available storage capacity and would require new transportation contracts to move the gas from the storage field to our customers. While ANRP and ANRS storage capacity and deliverability costs are lower than NNG's, the much higher related transportation costs make those alternatives more expensive overall. Likewise, NGPL's storage costs are competitive, but the additional transportation costs are much higher.

Finally, none of the available storage alternatives would provide the "on-demand" capabilities of NNG's Firm Deferred Delivery (FDD) storage service in our areas. FDD service allows for immediate withdrawal from and injections to storage in response to our customer's needs providing greater reliability of service. Furthermore, during higher or lower loads than expected, this service provides significant cost savings to customers by avoiding imbalance costs, overrun penalties, and the need to buy higher-priced gas in the intra-day spot market. Use of alternative storage providers would prevent us from immediately adjusting our demands, since we would be required to request changes using the industry-wide daily scheduling cycles on each pipeline providing transportation service. This would slow our response time to changing demand conditions making it more costly and difficult to ensure reliable service and potentially expose our customers to those higher imbalance costs and overrun penalties assessed by all our transporting pipelines.

Considering all factors, the lower reservation costs (including the pro-rata estimate of Kansas tax payment for the contract quantity being renewed, which in this case is Approximately $361,000), the limited available connecting transportation capacity, and the loss of operational flexibility; renewal of the NNG storage entitlement remains the best option for our customers when factoring in both cost effectiveness and reliability.

f. Geographic Diversity

In their February 17, 2023 Order[3] the Commission required utilities to discuss in future contract demand entitlement filings how "changes to their pipeline capacity

[3] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers,* Docket Nos. G999/CI-21-135, G008/M-21-138, G004/M-21-235, G002/CI-21-610, G011/CI-21-611, ORDER REQUIRING ACTIONS TO MITIGATE IMPACTS FROM FUTURE NATURAL GAS PRICE SPIKES, SETTING FILING REQUIREMENTS, AND INITIATING A PROCEEDING TO ESTABLISH GAS RESOURCE PLANNING REQUIREMENTS (February 17, 2023).

affects their supply diversity and, if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option."

The Company builds its gas transportation and storage portfolio with a focus to deliver safe, reliable, geographically diverse, gas service at a reasonable cost for its customers. The Company's plan provides significant operational and cost benefits to its customers through access to a geographically diverse supply mix, storage services, baseload supplies, and spot market purchases.

The Company transports the majority of its natural gas supply on Northern Natural Gas (NNG), Viking Transmission (Viking), and WBI Transmission Inc. (WBI) pipelines, which are the only interstate pipelines directly connected to our distribution systems. The Company also relies on Northern Border Pipeline, Great Lakes Gas Transmission (GLGT), and ANR Pipeline Company (ANR-P), which are not directly connected to our distribution systems. The Company holds storage services on NNG, ANR-P, and ANR Storage Company (ANR-S). This array of pipeline and storage services provides geographic diversity and strengthens reliability of the Company's natural gas supply.

Figure 1 shows the main supply and pipeline sources for NSP.

Figure 1
NSP Supply and Storage

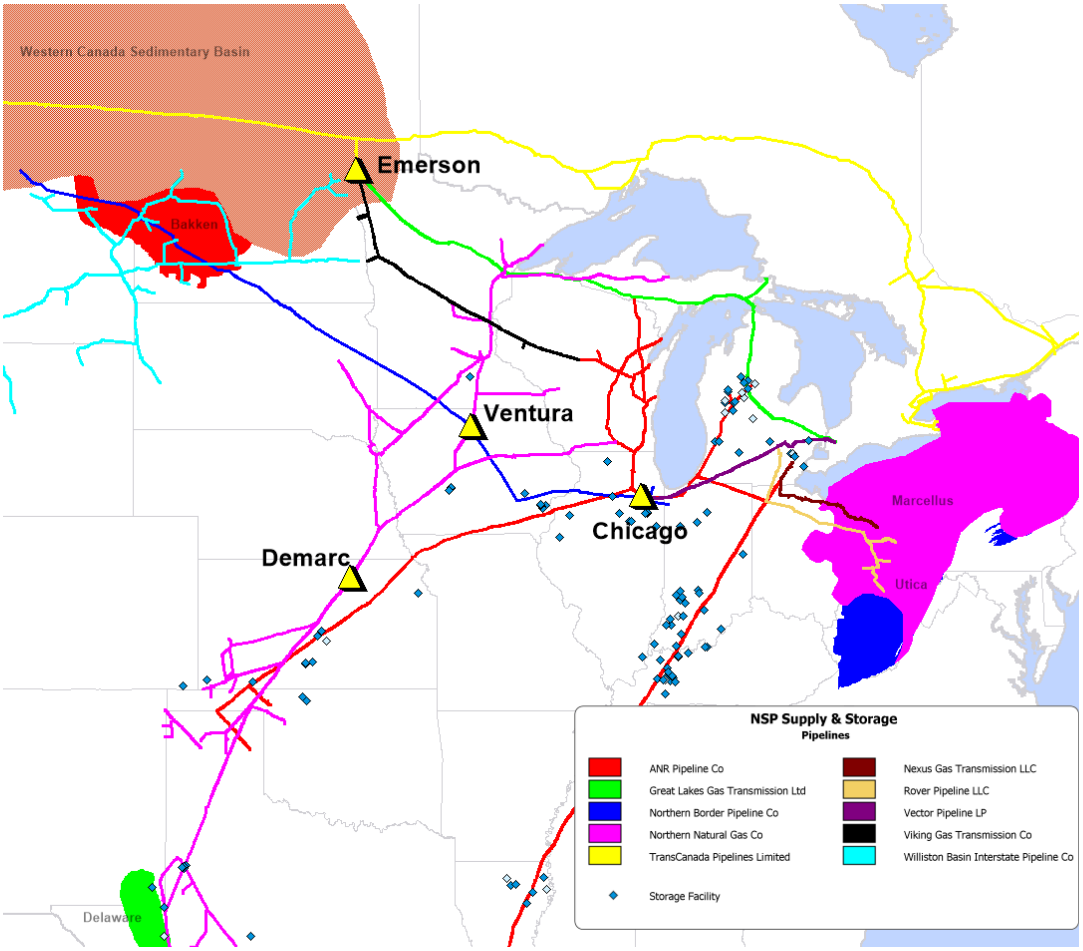

Table 2 below shows NSP's regional allocation of capacity by receipt point, accounting for upstream supply connections. For example, ANRS storage service in Michigan is upstream of receipt capacity on NNG at Carlton. Therefore, receipt capacity at Carlton does not include the amount supplied from ANRS storage.

Table 2
Geographic Diversity of Daily Supply Sources

	2025-2026		2024-2025		Change	
Receipt Point	**Dth/day**	**% Total**	**Dth/day**	**% Total**	**Dth/day**	**% Total**
ANR SW Headstation (OK)	4,829	0.67%	4,829	0.69%	0	-0.03%
NNG Beatrice (REX Interconnect)	9,239	1.28%	9,239	1.33%	0	-0.05%
CG Delivered (Emerson/Nymex)	24,000	3.31%	20,000	2.87%	4,000	0.44%
Chicago CG	88,500	12.22%	88,500	12.72%	0	-0.49%
VGT Chisago	12,876	1.78%	0	0.00%	12,876	1.78%
NNG Demarc	20,985	2.90%	20,985	3.02%	0	-0.12%
Emerson	118,453	16.36%	118,453	17.02%	0	-0.66%
GLGT/NNG Carlton	54,931	7.59%	54,931	7.89%	0	-0.31%
NNG Marshall	1,998	0.28%	1,998	0.29%	0	-0.01%
NNG Ventura	137,033	18.93%	125,876	18.09%	11,157	0.84%
WBI Baker	8,461	1.17%	8,461	1.22%	0	-0.05%
ANRP Storage	15,243	2.11%	15,171	2.18%	72	-0.07%
ANRS Storage	9,248	1.28%	9,248	1.33%	0	-0.05%
NNG Storage Service	218,280	30.15%	218,280	31.36%	0	-1.22%
Total	**724,076**		**695,971**			

As the table shows, of NSP's entire demand entitlements portfolio, approximately 33 percent is from storage (excluding peak shaving facilities), and the remainder from various receipt points. The three largest are NNG Ventura (18.93 percent), Emerson (16.37 percent), and Chicago (12.22 percent). The change from previous years is primarily due to the increase in NNG firm entitlement.

The result is a well-balanced, geographically diverse access to supply. The capacity portfolio provides access to five major price hubs (NNG Ventura, NNG Demarc, Emerson, Chicago, and ANR SW). No single supply source (after accounting for storage) accounts for more than approximately 20 percent of supply. This provides substantial geographic diversity and increases supply reliability. We paid no premiums this year to further supply diversity as our supply portfolio is already significantly diverse.

3. *Change in Interstate Pipeline Tariff Rates*

a. Change in ANR Pipeline Tariff Rates (effective November 1, 2025)

On April 30, 2025, ANR filed a Section 4 rate case (RP25-858) with FERC for new rates effective August 1, 2025 subject to refund and the outcome of the case. ANR proposed a 59 percent increase to its maximum tariff rate for firm transportation service in the Northern (ML-7) Segment, which is the primary zone in which NSP takes service. On May 12, 2025 NSP filed a protest requesting that the proposed rates be suspended for the maximum five-months, implemented thereafter subject to refund, and set for hearing. The case is ongoing, and NSP is an active participant to ensure just and reasonable rates moving forward. The proposed rate increase is reflected on both versions of **Attachment 1, Schedule 2, Pages 1 and 2**.

b. Change in Great Lakes Gas Transmission Tariff Rates (RP25-855) (effective November 1, 2025)

On April 30, 2025 Great Lakes Gas Transmission (GLGT) filed a general section 4 rate proceeding (RP25-855) with FERC for new rates to be effective August 1, 2025, subject to refund and the outcome of the case. GLGT proposed an average rate increase of approximately 22 percent to the maximum tariff rates. GLGT also proposed a modernization surcharge which would update annually to track capital costs on the pipeline during a proposed 4 year period. On May 12, 2025, NSP filed a protest requesting that the proposed rates be suspended for the maximum five-months, implemented thereafter subject to refund, and all matters including the modernization charge be set for hearing. The case is ongoing, and NSP is an active participant to ensure just and reasonable rates moving forward. The proposed rate increase is reflected on both versions of **Attachment 1, Schedule 2, Pages 1 and 2**.

c. Change in Northern Tariff Rates (effective January 1, 2026)

On July 1, 2025, Northern filed a Section 4 rate case (RP25-989) with FERC proposing an 85% maximum tariff rate increase to the Market Area transportation rate, where NSP receives service. We anticipate FERC will suspend the rates for the maximum five-month term to be effective January 1, 2026, subject to refund and the outcome of the case. NSP filed a protest of Northern's proposed rates on July 14, 2025, and will be an active participant in the case to ensure just and reasonable rates moving forward. While NSP has significant discounts on a large portion of its Northern capacity which limit the impact of the proposed rate increase, the change results in a significant impact on our demand costs and is the majority of the overall increase in demand costs. The proposed rate increases are included in **Attachment 1, Schedule 2, Pages 1 and 2** effective January 1, 2026.

4. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 86.42 percent to 86.02 percent. As in previous years, we calculate the allocation factor by dividing the DD forecasted demand for Minnesota by the DD demand for the Company. The Minnesota State, North Dakota State, and Company totals are provided on **Attachment 1, Schedule 1, page 1 of 5**. We used the traditional method of Avg. Monthly DD to update the allocation factors, since this approach accurately estimates the relationship of DD between the states and regional jurisdictions and accurately incorporates the monthly non-electronic pipeline measurements.

5. Change in Supplier Reservation Fees

The total change in supplier reservation charges is an increase of $412,627. **Attachment 1, Schedule 2, page 1** lists the changes in Supply Entitlements. This includes the projected costs of delivered supply to meet design day requirements in lieu of purchasing Viking seasonal capacity as discussed above.

B. The Utility's Design Day demand by customer class and the change in DD demand, if any, necessitating the demand revision

We provide the DD demand and change in DD demand by class as **Attachment 1, Schedule 3**.

C. Reserve Margin

We propose to increase our capacity reserve margin from 3.9 percent in November 2025 to 6.2 percent. The calculation of the reserve margin is noted in **Attachment 2, Schedule 1, page 3**. The increase is due to the acquisition of incremental entitlement on Northern to meet growth in design day. We believe this reserve margin is appropriate, given the need to balance the uncertainty of: (a) experiencing DD conditions; (b) actual consumer demand during DD conditions; and (c) the need to protect against the potential loss of a source of firm natural gas supply. However, if NSP continues to experience customer and demand growth, it may need to add more resources in coming years.

We add firm resources to meet projected firm customer demand and plan to maintain a reserve margin as close as practicable to either the capability of the largest pump at Wescott used to vaporize LNG or to the capability of either of the St. Paul metro propane-air peak shaving plants. Capacity decisions are based on projected demand, and the most economic method of adding capacity often involves adding increments that do not precisely match expected changes in demand. The reserve margin ensures reliability for our firm natural gas customers in Minnesota. The proposed 2025-2026 heating season DD reserve margin for Minnesota State is 48,711 Dth/day or 6.2 percent.

D. Summary of the levels of winter versus summer usage for all customer classes

We provide the summary of winter and summer sales by class on **Attachment 1, Schedule 4, page 1 of 1**.

E. Description of Design Day gas supply from all sources under the new level allocation or form of demand

We provide our firm supply entitlements on **Attachment 1, Schedule 5, page 1 of 1.**

Attachments
Effective November 1, 2025

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

Avg Monthly DD Method

2025-2026 Heating Season

Service Region (1)	Projected Jan 2026 Firm Res & Comm Customers (2)	Contracted Demand by Small & Large Demand Billed Comm'l Customers (3a)	(3b)	Load Variation (Dth/Degree) (4)	Degree per Design Day (5)	Monthly Base Use (Dth) (6)	Unacc. Factor (7)	Res & Comm Design Day (Dth) (8)	Total Design Day (Dth) (9)	Jurisdictional Allocation Factors (10)
METRO	345,508	76	12,805	0.0340355	91	1.2786153	0.0123	532,041	544,846	
BRAINERD	20,491	3	365	0.0258490	91	1.0662912	0.0123	27,600	27,965	
MAINLINE	16,233	9	2,483	0.0371920	88	1.2635237	0.0123	24,614	27,097	
MAINLINE-WELCOME	2,614	0	0	0.0188048	88	0.7138259	0.0123	3,147	3,147	
WILLMAR	13,201	4	998	0.0251197	88	1.1315511	0.0123	16,130	17,128	
PAYNESVILLE	46,224	26	4,482	0.0453519	94	1.1978386	0.0123	79,989	84,471	
VGT-CHISAGO	2,304	0	0	0.0163728	91	0.8611920	0.0123	2,687	2,687	
WATKINS	9,327	1	409	0.0196784	94	1.1939644	0.0123	12,777	13,186	
TOMAH	15,894	11	2,115	0.0354367	88	0.8546388	0.0123	23,338	25,453	
RED WING	6,884	6	1,901	0.0355702	88	1.3187277	0.0123	10,210	12,111	
GRAND FORKS MN	3,124	2	172	0.0401693	98	0.2543456	0.0123	4,757	4,930	
FARGO MN	14,858	7	2,808	0.0362531	98	0.2679288	0.0123	20,501	23,310	
MN State	**496,663**	**145**	**28,540**					**757,793**	**786,332**	**86.02%**
GRAND FORKS ND	17,418	0	0	0.0194158	98	2.6381613	0.0123	37,662	37,662	
FARGO ND	46,995	0	0	0.0166374	98	2.2348923	0.0123	87,029	87,029	
WBI ND	1,563	0	0	0.0175188	98	2.7445798	0.0123	3,069	3,069	
ND State	65,975	0	0					127,760	127,760	13.98%
TOTAL	**562,638**	**145**	**28,540**					**885,553**	**914,091**	**100.00%**

(1) Regional areas of the company.
(2) Estimated firm customers.
(3a) Firm Large and Small Commercial Demand Billed customers.
(3b) Firm contracted Design Day entitlement for Large and Small Commercial Demand Billed customers.
(4) Temperature dependent usage as determined by linear regression based on using 62 months January 2020 to February 2025.
(5) Degree Days for a Design Day in that region.
(6) Monthly base usage determined by linear regression based on using the same 60 months as in (4).
(7) Factor to correct for unaccounted gas usage.
(8) Estimated Design Day Demand for Firm Residential & Commercial Customers.
(9) Estimated Total Design Day for Firm Residential, Commercial, and Demand Billed Customers.
(10) Jurisdictional allocation factors based on percent of Total Company Design Day Demand.

Division/Region (1)	Projected Firm Jan 2026 Cust (2)	Load Variation (Dth/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Dth) (5) Intercept	R-Square	T-Stat	P-Value	Lost & Unacc. Factor (6)	Design Day (Dth) 2026				2025 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
									Unacc. Volume	Load Variation	Day Base	Total				
METRO																
Total Residential	322,600	0.0102478	91	1.2491501	0.9591	37.8542	0.0000	0.0089	2,795	300,841	13,256	**316,892**	325,863	(8,971)	24,468	**341,361**
Total Small Commercial	14,898	0.0299515	91	2.0709711	0.9358	29.8245	0.0000	0.0089	370	40,605	1,015	**41,991**	42,071	(80)	3,242	**45,233**
Total Large Commercial	8,010	0.1727979	91	29.9062776	0.9514	34.5798	0.0000	0.0089	1,191	125,951	7,880	**135,022**	137,685	(2,663)	10,426	**145,447**
Industrial	76	Contract Demand	-	-				-	-	-	-	**12,805**	12,826	(21)	-	**12,805**
	345,584	0.0340355		1.27861534					4,357	467,397	22,150	**506,710**	518,445	(11,736)	38,136	**544,846**
														-2.3%		
BRAINERD																
Total Residential	18,830	0.0106295	91	0.9969676	0.9676	42.6789	0.0000	0.0089	168	18,214	618	**18,999**	19,770	(771)	1,467	**20,466**
Total Small Commercial	1,358	0.0196418	91	2.0086500	0.9396	30.8076	0.0000	0.0089	22	2,427	90	**2,539**	2,564	(25)	196	**2,735**
Total Large Commercial	303	0.1291853	91	49.0148727	0.9431	31.8108	0.0000	0.0089	36	3,559	488	**4,084**	4,519	(435)	315	**4,399**
Industrial	3	Contract Demand	-	-				-	-	-	-	**365**	365	0	-	**365**
	20,494	0.0258490		1.066291157					226	24,200	1,195	**25,987**	27,217	(1,231)	1,978	**27,965**
														-4.5%		
MAINLINE																
Total Residential	14,723	0.0097523	88	1.2906904	0.9434	31.9160	0.0000	0.0089	118	12,635	625	**13,378**	13,403	(25)	1,033	**14,411**
Total Small Commercial	1,076	0.0245140	88	0.9685582	0.6168	9.9590	0.0000	0.0089	21	2,322	34	**2,377**	2,422	(45)	184	**2,561**
Total Large Commercial	434	0.1679843	88	43.2346727	0.9196	26.4388	0.0000	0.0089	63	6,415	617	**7,095**	7,088	7	548	**7,642**
Industrial	9	Contract Demand	-	-				-	-	-	-	**2,483**	2,483	0	-	**2,483**
	16,242	0.0371920		1.263523737					202	21,372	1,277	**25,333**	25,396	(63)	1,764	**27,097**
														-0.2%		
MAINLINE-WELCOME																
Total Residential	2,471	0.0111038	88	0.6737735	0.8384	17.8189	0.0000	0.0089	22	2,414	55	**2,491**	2,495	(4)	192	**2,683**
Total Small Commercial	124	0.0163568	88	0.4877833	0.8837	21.5474	0.0000	0.0089	2	178	2	**182**	190	(9)	14	**196**
Total Large Commercial	20	0.0975488	88	121.3320554	0.1440	3.3553	0.0014	0.0089	2	168	78	**249**	285	(37)	19	**268**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,614	0.0188048		0.713825916					26	2,761	135	**2,921**	2,970	(49)	226	**3,147**
														-1.6%		
WILLMAR																
Total Residential	12,279	0.0097139	88	1.1314072	0.9333	29.2361	0.0000	0.0089	97	10,497	457	**11,051**	9,551	1,500	853	**11,904**
Total Small Commercial	724	0.0203450	88	1.1283882	0.7212	12.6016	0.0000	0.0089	12	1,297	27	**1,335**	1,316	19	103	**1,438**
Total Large Commercial	198	0.1346050	88	34.5732140	0.9102	24.8876	0.0000	0.0089	23	2,340	225	**2,588**	2,458	130	200	**2,787**
Industrial	4	Contract Demand	-	-				-	-	-	-	**998**	998	0	-	**998**
	13,205	0.0251197		1.131551132					132	14,133	709	**15,972**	14,324	1,649	1,156	**17,128**
														11.5%		
PAYNESVILLE																
Total Residential	41,188	0.0095544	94	1.0732950	0.9601	38.3075	0.0000	0.0089	342	36,992	1,454	**38,788**	38,217	572	2,995	**41,783**
Total Small Commercial	3,436	0.0302339	94	2.7830368	0.9440	32.0855	0.0000	0.0089	90	9,764	315	**10,169**	10,007	161	785	**10,954**
Total Large Commercial	1,600	0.1558435	94	31.1065068	0.9515	34.6208	0.0000	0.0089	223	23,438	1,637	**25,299**	25,019	279	1,953	**27,252**
Industrial	26	Contract Demand	-	-				-	-	-	-	**4,482**	4,104	378	-	**4,482**
	46,250	0.0453519		1.197838614					655	70,195	3,406	**78,738**	77,348	1,390	5,734	**84,471**
														1.8%		
VGT-CHISAGO																
Total Residential	2,196	0.0107093	91	0.8710456	0.9299	28.4645	0.0000	0.0089	20	2,140	63	**2,223**	2,348	(125)	172	**2,394**
Total Small Commercial	96	0.0180979	91	0.5304990	0.8846	21.6444	0.0000	0.0089	1	158	2	**161**	176	(15)	12	**173**
Total Large Commercial	12	0.0949014	91	8.2734738	0.9074	24.4646	0.0000	0.0089	1	107	3	**111**	148	(37)	9	**120**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,304	0.0163728		0.861192022					22	2,404	68	**2,494**	2,672	(177)	193	**2,687**
														-6.6%		

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2025-2026 Heating Season

Division/Region (1)	Projected Firm Jan 2026 Cust (2)	Load Variation (Dth/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Dth) (5) Intercept	R-Square	T-Stat	P-Value	Lost & Unacc. Factor (6)	Design Day (Dth) 2026 Unacc. Volume	Design Day (Dth) 2026 Load Variation	Design Day (Dth) 2026 Day Base	Design Day (Dth) 2026 Total	2025 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
WATKINS																
Total Residential	8,996	0.0099876	94	1.1842728	0.9221	26.8860	0.0000	0.0089	78	8,446	350	**8,875**	9,051	(176)	685	**9,560**
Total Small Commercial	244	0.0278308	94	1.5459881	0.6524	10.7460	0.0000	0.0089	6	639	12	**657**	696	(39)	51	**708**
Total Large Commercial	87	0.2767972	94	19.2086976	0.8314	6.5091	0.0000	0.0089	21	2,254	55	**2,330**	1,475	854	180	**2,509**
Industrial	1	Contract Demand	-	-				-	-	-	-	**409**	409	0	-	**409**
	9,328	0.0196784		1.193964419					105	11,339	418	**12,271**	11,632	639 5.5%	916	**13,186**
TOMAH																
Total Residential	14,301	0.0096040	88	0.5407178	0.9578	37.2217	0.0000	0.0089	110	12,086	254	**12,451**	13,129	(679)	961	**13,412**
Total Small Commercial	1,196	0.0240869	88	4.5476094	0.9135	25.4047	0.0000	0.0089	24	2,535	179	**2,738**	2,905	(167)	211	**2,950**
Total Large Commercial	397	0.1745596	88	24.1841316	0.9462	32.7533	0.0000	0.0089	57	6,103	316	**6,476**	6,945	(469)	500	**6,976**
Industrial	11	Contract Demand	-	-				-	-	-	-	**2,115**	2,081	35	-	**2,115**
	15,905	0.0354367		0.854638809					191	20,725	749	**23,780**	25,061	(1,281) -5.1%	1,673	**25,453**
RED WING																
Total Residential	6,186	0.0098611	88	1.1075025	0.9466	32.8955	0.0000	0.0089	50	5,368	225	**5,643**	6,081	(438)	436	**6,079**
Total Small Commercial	525	0.0206506	88	3.8713610	0.9195	26.4205	0.0000	0.0089	9	954	67	**1,030**	1,091	(60)	80	**1,110**
Total Large Commercial	173	0.1716505	88	29.1502983	0.9232	27.0950	0.0000	0.0089	25	2,614	166	**2,805**	3,191	(386)	217	**3,021**
Industrial	6	Contract Demand	-	-				-	-	-	-	**1,901**	1,901	0	-	**1,901**
	6,890	0.0355702		1.318727682					84	8,936	458	**11,379**	12,263	(884) -7.2%	732	**12,111**
GRAND FORKS MN																
Total Residential	2,779	0.0096396	98	0.1984943	0.9402	30.9917	0.0000	0.0089	24	2,625	18	**2,667**	2,749	(82)	206	**2,873**
Total Small Commercial	252	0.0210926	98	0.5291917	0.9269	27.8202	0.0000	0.0089	5	521	4	**530**	536	(7)	41	**571**
Total Large Commercial	93	0.1264567	98	16.8758126	0.9517	34.6809	0.0000	0.0089	11	1,157	52	**1,219**	1,285	(65)	94	**1,314**
Industrial	2	Contract Demand	-	-				-	-	-	-	**172**	172	0	-	**172**
	3,126	0.0401693		0.254345629					39	4,303	74	**4,589**	4,742	(154) -3.2%	341	**4,930**
FARGO MN																
Total Residential	13,352	0.0081329	98	0.1976505	0.9550	36.0034	0.0000	0.0089	95	10,642	87	**10,824**	11,348	(524)	836	**11,660**
Total Small Commercial	1,099	0.0203969	98	0.8184210	0.8602	19.4018	0.0000	0.0089	20	2,197	30	**2,246**	2,364	(118)	173	**2,420**
Total Large Commercial	408	0.1355534	98	36.6880606	0.9509	34.3984	0.0000	0.0089	53	5,417	492	**5,962**	6,111	(150)	460	**6,422**
Industrial	7	Contract Demand	-	-				-	-	-	-	**2,808**	2,808	0	-	**2,808**
	14,865	0.0362531		0.267928797					168	18,255	609	**21,840**	22,632	(792) -3.5%	1,470	**23,310**
MN STATE																
Total Residential	**459,901**											**444,281**	**454,004**	**-9,723**	**34,305**	**478,586**
Total Small Commercial	**25,028**											**65,955**	**66,339**	**-384**	**5,093**	**71,048**
Total Large Commercial	**11,734**											**193,238**	**196,209**	**-2,972**	**14,921**	**208,158**
Contract Demand	**145**											**28,540**	**28,148**	**392**	**0**	**28,540**
	496,808											**732,014**	**744,702**	**-12,688** **-1.7%**	**54,318**	**786,332**

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2025-2026 Heating Season

Division/Region (1)	Projected Firm Jan 2026 Cust (2)	Load Variation (Dth/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Dth) (5) Intercept	R-Square	T-Stat	P-Value	Lost & Unacc. Factor (6)	Design Day (Dth) 2026 Unacc. Volume	Load Variation	Day Base	Total	2025 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND																
Total Residential	14,976	0.0091026	98	0.4675634	0.9549	35.9673	0.0000	0.0089	121	13,360	230	**13,711**	13,299	412	1,059	**14,770**
Total Small Commercial	2,442	0.0826761	98	15.9523301	0.9300	28.4946	0.0000	0.0089	187	19,782	1,281	**21,251**	20,028	1,223	1,641	**22,892**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0089	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	17,418	0.0194158		2.638161279					308	33,142	1,512	**34,962**	33,328	1,635	2,700	**37,662**
														4.9%		
FARGO ND																
Total Residential	39,627	0.0085299	98	0.4166135	0.9452	32.4469	0.0000	0.0089	300	33,125	543	**33,968**	34,777	(809)	2,623	**36,591**
Total Small Commercial	7,368	0.0602390	98	12.0136010	0.9499	34.0309	0.0000	0.0089	413	43,498	2,912	**46,823**	45,857	966	3,615	**50,438**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0089	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	46,995	0.0166374		2.234892299					713	76,623	3,455	**80,791**	80,633	158	6,238	**87,029**
														0.2%		
WBI ND																
Total Residential	1,337	0.0104300	98	0.1600412	0.8615	19.5069	0.0000	0.0089	12	1,367	7	**1,386**	1,395	(9)	107	**1,493**
Total Small Commercial	225	0.0596325	98	18.0988938	0.7507	13.5896	0.0000	0.0089	13	1,316	134	**1,463**	1,389	73	113	**1,576**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0089	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	1,563	0.0175188		2.744579847					25	2,683	141	**2,849**	2,784	65	220	**3,069**
														2.3%		
ND STATE																
Total Residential	**55,940**											**49,065**	**49,471**	**-406**	**3,789**	**52,854**
Total Small Commercial	**10,035**											**69,537**	**67,274**	**2,262**	**5,369**	**74,906**
Total Large Commercial	**0**											**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**											**-**	**-**	**-**	**-**	**-**
	65,975											**118,602**	**116,745**	**1,857**	**9,158**	**127,760**
														1.6%		
Grand Total																
Total Residential	**515,842**											**493,347**	**503,476**	**(10,129)**	**38,093**	**531,440**
Total Small Commercial	**35,063**											**135,492**	**133,614**	**1,878**	**10,462**	**145,953**
Total Large Commercial	**11,734**											**193,238**	**196,209**	**(2,972)**	**14,921**	**208,158**
Contract Demand	**145**											**28,540**	**28,148**	**392**	**-**	**28,540**
	562,783											**850,616**	**861,447**	**(10,831)**	**63,476**	**914,092**
														-1.3%		

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2026 FORECAST	2025 FORECAST	Difference	% Diff
METRO	345,508	344,961	547	0.2%
BRAINERD	20,491	21,164	(673)	-3.2%
MAINLINE	16,233	15,690	543	3.5%
MAINLINE-WELCOME	2,614	2,593	21	0.8%
WILLMAR	13,201	11,058	2,143	19.4%
PAYNESVILLE	46,224	44,165	2,059	4.7%
VGT-CHISAGO	2,304	2,380	(76)	-3.2%
WATKINS	9,327	9,228	99	1.1%
TOMAH	15,894	16,388	(494)	-3.0%
RED WING	6,884	7,238	(354)	-4.9%
GRAND FORKS MN	3,124	3,244	(120)	-3.7%
FARGO MN	14,858	15,259	(401)	-2.6%
MN STATE	496,663	493,367	3,296	0.7%
GRAND FORKS ND	17,418	16,750	668	4.0%
FARGO ND	46,995	47,074	(79)	-0.2%
WBI ND	1,563	1,566	(4)	-0.2%
ND STATE	65,975	65,391	585	0.9%
TOTAL NSP MN	562,638	558,757	3,881	**0.7%**

2026 Customer Counts

	MN	ND	
Res	459,901	55,940	**515,842**
Sm Com	25,028	10,035	**35,063**
Lg Com	11,734	0	**11,734**
Ind	145	0	**145**
	496,808	65,975	**562,783**

2026 Design Day Use By Customer Class

	MN	ND	
Res	478,586	52,854	**531,440**
Sm Com	71,048	74,906	**145,953**
Lg Com	208,159	0	**208,159**
Ind	28,540	0	**28,540**
	786,332	127,760	**914,092**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2026 FORECAST	2025 FORECAST	Difference	% Diff
METRO	544,846	546,444	(1,598)	-0.3%
BRAINERD	27,965	28,704	(739)	-2.6%
MAINLINE	27,097	26,664	432	1.6%
MAINLINE-WELCOME	3,147	3,135	12	0.4%
WILLMAR	17,128	15,062	2,067	13.7%
PAYNESVILLE	84,471	81,403	3,068	3.8%
VGT-CHISAGO	2,687	2,820	(132)	-4.7%
WATKINS	13,186	12,253	933	7.6%
TOMAH	25,453	26,333	(880)	-3.3%
RED WING	12,111	12,837	(726)	-5.7%
GRAND FORKS MN	4,930	4,996	(66)	-1.3%
FARGO MN	23,310	23,730	(420)	-1.8%
MN STATE	786,332	784,381	1,951	0.2%
GRAND FORKS ND	37,662	35,173	2,489	7.1%
FARGO ND	87,029	85,098	1,931	2.3%
WBI ND	3,069	2,939	130	4.4%
ND STATE	127,760	123,210	4,549	3.7%
TOTAL NSP MN	914,092	907,591	6,500	0.7%

MN / ND Allocation Factors

2026 DD	2025 DD	
0.8602	0.8642	**MN State Allocation**
0.1398	0.1358	**ND State Allocation**

NNG SYSTEM	2026 FORECAST	2025 FORECAST	Difference	% Diff
METRO	544,846	546,444	(1,598)	-0.3%
BRAINERD	27,965	28,704	(739)	-2.6%
MAINLINE	27,097	26,664	432	1.6%
MAINLINE-WELCOME	3,147	3,135	12	0.4%
WILLMAR	17,128	15,062	2,067	13.7%
PAYNESVILLE	84,471	81,403	3,068	3.8%
WATKINS	13,186	12,253	933	7.6%
TOMAH	25,453	26,333	(880)	-3.3%
RED WING	12,111	12,837	(726)	-5.7%
NNG SUBTOTAL	755,405	752,836	2,569	0.3%

VGT SYSTEM				
VGT-CHISAGO	2,687	2,820	(132)	-4.7%
GRAND FORKS MN	4,930	4,996	(66)	-1.3%
FARGO MN	23,310	23,730	(420)	-1.8%
GRAND FORKS ND	37,662	35,173	2,489	7.1%
FARGO ND	87,029	85,098	1,931	2.3%
WBI ND	3,069	2,939	130	4.4%
VGT SUBTOTAL	158,686	154,755	3,931	2.5%
VGT & NNG TOTAL	914,092	907,591	6,500	0.7%

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5	$ (499,763.08)
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5	$ 795,476.21
ANR FTS-1 (Nov-Oct)	(5,433)	$ 6.5884	7	$ (250,563.44)
ANR FTS-1 (Nov-Oct)	5,433	$ 10.4868	7	$ 398,823.49
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62
ANR FSS (Nov-Oct)	(15,226)	$ 2.1126	12	$ (385,997.37)
ANR FSS (Jan-Dec)	15,226	$ 2.5372	12	$ 463,576.89
ANR FSS (Jan-Dec)	17	$ 2.5372	12	$ 517.59
ANRS FSS (Apr-July)	(9,248)	$ 1.4160	5	$ (65,475.84)
ANRS FSS (Apr-July)	9,248	$ 3.4645	5	$ 160,198.48
ANR FTS-1 (Apr-July)	2	$ 10.4868	7	$ 146.82
NNG TFX (Nov-Mar)	1,157	$ 25.7990	5	$ 149,247.22
NNG TFX (Apr-Oct)	1,157	$ 9.6760	7	$ 78,365.92
NNG TFX (Nov-Mar)	4,094	$ 25.7990	5	$ 528,105.53
NNG TFX (Apr-Oct)	4,094	$ 9.6760	7	$ 277,294.81
		[PROTECTED DATA BEGINS		
NNG TFX (Nov-Oct)	6,667			
NNG TFX (Nov-Oct)	3,333			
NNG TFX (Nov-Oct)	3,333			
NNG TFX (Nov-Oct)	1,613			
NNG TFX (Nov-Oct)	1,613			
NNG TFX (Nov-Oct)	7,169			
NNG TFX (Nov-Oct)	7,169			
			PROTECTED DATA ENDS]	
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5	$ (143,623.37)
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5	$ 160,045.49
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5	$ (378,520.64)
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5	$ 421,801.28
Total				$ 7,819,887.41

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Total	4,000	$ 412,627.00
Total MN & ND Demand Cost Adjustment		**$ 8,232,514.41**
Minnesota Allocation Factor (MN/ND Allocated Demand)		86.02%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 7,081,882.37**

[1]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v.4.0.1 Effective November 1, 2025
[2]GLGT Volume No. 1, Part 5.0 - Statement of Rates, v.60.0.0, Effective Novemeber 1, 2025
3NNG Seventh Revised Volume No. 1, Twenty First Revised Sheet No. 50, Effective January 1, 2026
4NNG Seventh Revised Volume No. 1, Twenty Fourth Revised Sheet No. 51, Effective January 1, 2026

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
Attachment 1, Schedule 2

Protected data is shaded.

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2024 SUPPLEMENTAL FILED COSTS				**$50,970,508.65**	**$35,820,718.55**	**$86,791,227.20**				
2024 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2024 ACTUAL COSTS				**$ 50,970,508.65**	**$ 35,820,718.55**	**$ 86,791,227.20**				
CHANGES FOR 2025 FILING										
Contract Demand Entitlement Changes										
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)		$ (5,257,543.20)			$ (5,257,543.20)	1
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40		$ 8,368,466.40			$ 8,368,466.40	1
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5		$ (499,763.08)	$ (499,763.08)			$ (499,763.08)	1
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5		$ 795,476.21	$ 795,476.21			$ 795,476.21	1
ANR FTS-1 (Apr-July)	(5,433)	$ 6.5884	7		$ (250,563.44)	$ (250,563.44)			$ (250,563.44)	1
ANR FTS-1 (Apr-July)	5,433	$ 10.4868	7		$ 398,823.49	$ 398,823.49			$ 398,823.49	1
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)		$ (1,739,337.60)			$ (1,739,337.60)	1
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20		$ 2,768,515.20			$ 2,768,515.20	1
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)		$ (816,487.32)			$ (816,487.32)	2
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62		$ 1,564,352.62			$ 1,564,352.62	2
ANR FSS (Nov-Oct)	(15,226)	$ 2.1126	12		$ (385,997.37)	$ (385,997.37)			$ (385,997.37)	2
ANR FSS (Jan-Dec)	15,226	$ 2.5372	12		$ 463,576.89	$ 463,576.89			$ 463,576.89	2
ANR FSS (Jan-Dec)	17	$ 2.5372	12		$ 517.59	$ 517.59			$ 517.59	2
ANRS FSS (Apr-July)	(9,248)	$ 1.4160	5		$ (65,475.84)	$ (65,475.84)			$ (65,475.84)	1
ANRS FSS (Apr-July)	9,248	$ 3.4645	5		$ 160,198.48	$ 160,198.48			$ 160,198.48	1
ANR FTS-1 (Apr-July)	2	$ 10.4868	7		$ 146.82	$ 146.82			$ 146.82	1
NNG TFX (Nov-Mar)	1,157	$ 25.7990	5		$ 149,247.22	$ 149,247.22	$ 149,247.22			3
NNG TFX (Apr-Oct)	1,157	$ 9.6760	7	$ 78,365.92		$ 78,365.92	$ 78,365.92			3
NNG TFX (Nov-Mar)	4,094	$ 25.7990	5		$ 528,105.53	$ 528,105.53	$ 528,105.53			3
NNG TFX (Apr-Oct)	4,094	$ 9.6760	7	$ 277,294.81		$ 277,294.81	$ 277,294.81			3
		[PROTECTED DATA BEGINS								
NNG TFX (Nov-Oct)	6,667									3
NNG TFX (Nov-Oct)	3,333									3
NNG TFX (Nov-Oct)	3,333									3
NNG TFX (Nov-Oct)	1,613									3
NNG TFX (Nov-Oct)	1,613									3
NNG TFX (Nov-Oct)	7,169									3
NNG TFX (Nov-Oct)	7,169									3
						PROTECTED DATA ENDS]				
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5		$ (143,623.37)	$ (143,623.37)		$ (143,623.37)		4
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5		$ 160,045.49	$ 160,045.49		$ 160,045.49		4
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)		$ (307,711.74)		$ (307,711.74)		4
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98		$ 342,895.98		$ 342,895.98		4
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5		$ (378,520.64)	$ (378,520.64)		$ (378,520.64)		4
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5		$ 421,801.28	$ 421,801.28		$ 421,801.28		4
Total				$ 5,995,689.07	$ 1,824,198.35	$ 7,819,887.42	$ 2,220,094.57	$ 94,887.00	$ 5,504,905.85	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										5
										5
										5
										5
										5
									PROTECTED DATA ENDS]	
Total				$0.00	$412,627.00	$412,627.00	$0.00	$412,627.00	$0.00	
TOTAL OF 2025 CHANGES				**$ 5,995,689.07**	**$ 2,236,825.35**	**$ 8,232,514.42**	**$ 2,220,094.57**	**$ 507,514.00**	**$ 5,504,905.85**	
2025 COSTS				**$ 56,966,197.72**	**$ 38,057,543.90**	**$ 95,023,741.62**				
2025 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							81%	19%		6

Footnote

1. Rate change in accordnace with approved Rate Case Settlement (RP25-858), Rate effective November 1, 2025.
2. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
3. Acquisition of new capacity on NNG as part of Northern Lights 2025 to meet Design Day requirements of Minnesota customers.
4. Rate change due to ongoing Rate Case (RP25-855), Interim Settlement Rates effective November 1, 2025.
5. Expired peaking supply contract with demand charges in effect November 1, 2025 through March 31, 2026.
6. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purpocses of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS

Design Day: Heating Season 2025-2026

DESIGN DAY CALCULATION

State of Minnesota	Jan-2026 Budget Customer	2026 MMBtu Design Day[1]	2025 MMBtu Design Day[1]	MMBtu Change
Residential	459,901	478,586	479,145	(559)
Commercial	36,762	279,206	277,088	2,118
Demand Billed	145	28,540	28,148	392
State of Minnesota Total	**496,808**	**786,332**	**784,381**	**1,951**
State of North Dakota Total	65,975	127,760	123,210	4,549
Total Xcel Energy - Gas Utility Operations	562,783	914,091	907,591	6,500

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

UPC DD Method

Minnesota Company	Jan-2026 Budget Customer	Jan-2025 Budget Customer	Change
Residential	515,842	512,542	3,300
Commercial	46,797	46,215	581
TOTAL	562,638	558,757	3,881
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	885,552	879,444	
Demand Billed Customers	145	146	
Contracted Billing Demand of Demand Billed Customers	28,540	28,148	
Projected Design Day (Dth)	914,092	907,592	6,500

[2] Determined from Peak Day usage at an average temperature of -15 degrees Fahrenheit on Thursday, Jan. 29, 2004

MINNESOTA COMPANY ENTITLEMENT ESTIMATE PER CUSTOMER

	Jan-2026 Budget	Jan-2025 Budget
Reserve Margin	56,625	35,093
Total Available Capacity	970,717	942,684
Entitlement per Customer	1.7248	1.6867

Northern States Power Company

DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER

Design Day: Heating Season 2025-2026

Protected data is shaded.

	Description	Values	Units	Equation
(1)	Date of Peak Day	January 29, 2004		
(2)	Day of the Week	Thursday		
(3)	Total Throughput including Peakshaving	648,400	Dth	
(4)	Actual Large and Small Comm'l Demand Billed Usage	(13,863)	Dth	
(5)	Total Throughput including Peakshaving less Demand Billed	634,537	Dth	(5) = (3) - (4)
(6)	Interruptible Customers Status	All Curtailed		
(7)	Average Actual Gas Day Temperature	-15	Deg F	
(8)	Heating Degree Days (HDD) 65 degree base	80	HDDs	(8) = 65 - (7)
		[PROTECTED DATA BEGINS		
(9)	Limited Firm/Standby Dth Demand on system		Dth	
(10)	Total Firm Throughput less Ltd F/Stdby & Demand Billed Customers		Dth	(10) = (5) + (9)
(11)	2004 Non-HDD Sensitive Base Dth[1]		Dth	
(12)	Total HDD sensitive Firm throughput		Dth	(12) = (10) + (11)
(13)	Actual Peak Day Dth/HDD		Dth/HDD	(13) = (12) / (8)
		PROTECTED DATA ENDS]		
(14)	Base + (Actual Dth/HDD * 91 HDDs)	695,134	Dth	(14) = -(11) + [(13) x 91 HDDs]
(15)	Base + (Actual Dth/HDD * 91 HDDs) + Actual Demand Billed Usage	708,997		(15) = (14) + -(4)
(16)	Average Monthly Projected 2004 Design Day[1]	677,930	Dth	
(17)	Actual Peak Day UPC vs. Avg Monthly Design Day	(31,067)	Dth	(17) = (16) - (15)
(18)	Average Monthly 2004 Design Day Reserve Margin[1]	44,733	Dth	
(19)	Actual 2004 Reserve Margin based on Peak Actuals	13,666	Dth	(19) = (18) + (17)
(20)	January 2004 Projected Firm Residential & Comm'l Customers[1]	441,656	Customers	
(21)	Peak Day Actual Use Per Residential & Comm'l Firm Customer	1.57393	Dth/customer	(21) = (14) / (20)

[1] As described in Company's 2003 - 2004 Contract Demand Filing

Northern States Power Company
MINNESOTA STATE HISTORICAL SALES - SEASONAL USAGE
(Dth)

Customer Class	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Total	Winter	Summer
Residential	813,759	604,851	650,740	958,029	1,811,111	5,564,749	7,319,429	6,970,334	5,637,952	3,605,350	1,641,571	1,106,953	36,684,828	27,303,575	9,381,253
Interdepartmental	185	176	222	181	238	442	2,079	1,462	1,258	731	607	198	7,779	5,479	2,300
Small Commercial Firm	51,766	91,186	91,311	129,202	229,554	799,095	1,155,598	1,127,831	972,064	536,969	274,640	166,671	5,625,886	4,284,141	1,341,744
Large Commercial Firm	443,391	410,596	388,865	555,034	893,686	2,339,168	3,131,317	2,891,429	2,777,230	1,731,457	981,286	611,546	17,155,005	12,032,829	5,122,176
Commercial Firm	495,342	501,958	480,398	684,417	1,123,477	3,138,705	4,288,994	4,020,721	3,750,552	2,269,157	1,256,534	778,415	22,788,670	16,322,449	6,466,220
Small Commercial Demand Billed	5,741	8,082	4,285	6,714	6,307	13,031	18,180	16,711	15,295	13,287	7,439	3,001	118,074	69,524	48,550
Large Commercial Demand Billed	132,075	148,344	143,821	148,332	175,449	287,179	342,461	362,255	325,729	240,731	195,961	161,547	2,663,885	1,493,073	1,170,811
Large Demand Billed - Generation	8,594	5,829	2,062	2,379	12,210	17,468	8,458	12,021	13,733	7,497	2,888	1,282	94,421	63,890	30,531
Commercial Demand Billed	146,410	162,255	150,169	157,425	193,966	317,679	369,099	390,988	354,756	261,515	206,288	165,830	2,876,380	1,626,488	1,249,892
Total Commercial Firm	641,753	664,212	630,567	841,842	1,317,443	3,456,384	4,658,092	4,411,709	4,105,308	2,530,672	1,462,822	944,245	25,665,049	17,948,937	7,716,113
Total Firm	1,455,512	1,269,063	1,281,307	1,799,870	3,128,554	9,021,134	11,977,522	11,382,043	9,743,260	6,136,022	3,104,393	2,051,198	62,349,878	45,252,512	17,097,366
Small Interruptible	68,166	35,675	39,430	53,236	85,381	167,791	209,081	177,758	160,346	119,305	108,790	54,341	1,279,298	800,356	478,941
Medium Interruptible	235,306	203,631	237,008	217,735	316,175	439,691	540,801	488,628	508,661	381,274	295,324	217,093	4,081,327	2,293,956	1,787,371
Large Interruptible	133,493	146,465	119,923	95,873	173,694	172,220	270,139	325,434	285,383	209,143	182,766	121,577	2,236,111	1,226,870	1,009,241
Med. & Lg. Interruptible - Generation	435	4,729	909	1,138	1,376	2,608	1,543	2,129	1,729	3,852	1,389	2,423	24,260	9,385	14,875
Total Interruptible	437,400	390,500	397,271	367,981	576,626	782,309	1,021,564	993,948	956,120	713,573	588,269	395,434	7,620,995	4,330,567	3,290,428
Total Firm and Interruptible	1,892,912	1,659,563	1,678,578	2,167,852	3,705,180	9,803,443	12,999,085	12,375,991	10,699,380	6,849,596	3,692,662	2,446,632	69,970,873	49,583,079	20,387,794
Firm Transportation	186,330	208,063	178,935	177,752	196,221	216,342	213,505	214,279	189,717	188,223	163,454	154,050	2,286,871	1,030,064	1,256,807
Interruptible Transportation	94,043	93,235	100,540	98,463	105,217	133,521	163,610	184,314	171,488	143,666	124,915	108,255	1,521,267	758,149	763,118
Negotiated Transporation	471,433	435,789	475,442	495,777	678,969	718,409	775,501	758,900	678,825	721,957	603,820	581,083	7,395,905	3,610,604	3,785,301
Interdepartmental Transport - Generation	5,366,773	5,460,045	3,567,569	1,970,405	3,664,485	3,465,486	2,331,841	2,081,815	1,857,715	1,467,103	2,830,198	4,740,622	38,804,057	13,401,342	25,402,715
Total Transportation	6,118,579	6,197,132	4,322,486	2,742,397	4,644,892	4,533,758	3,484,457	3,239,308	2,897,745	2,520,949	3,722,387	5,584,010	50,008,100	18,800,160	31,207,941
Total Customer Sales	8,011,491	7,856,695	6,001,064	4,910,249	8,350,072	14,337,201	16,483,542	15,615,299	13,597,124	9,370,545	7,415,049	8,030,642	119,978,973	68,383,239	51,595,734
Monthly Heating Degree Days	0	3	21	264	798	1,246	1,530	1,322	807	511	184	31	6,717	5,703	1,014

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2025-2026 Heating Season

Protected data is shaded.

Firm Supplies (1)	Current Quantity Effective Nov-24 Dth/Day	Proposed Quantity Effective Nov-25 Dth/Day	Proposed Quantity Change Nov-25 Dth/Day
A. Upstream Supply			
	[PROTECTED DATA BEGINS		
ANR Firm 3rd Party (2)			
ANRP Storage (2)			
ANR Storage Company (3)			
GLGT Firm 3rd Party (3)			
			PROTECTED DATA ENDS]
B. Minnesota Company Delivered Supply			
	[PROTECTED DATA BEGINS		
WBI Firm 3rd Party			
VGT Firm 3rd Party			
NNG Firm 3rd Party			
NNG FDD Storage			**PROTECTED DATA ENDS]**
LP Peak Shaving	90,000	90,000	-
LNG Peak Shaving	156,000	156,000	-
TOTAL	942,684	970,717	28,033
C. Minnesota State Delivered Supply			
State of MN Allocators	86.42%	86.02%	
TOTAL	814,710	835,043	20,333

(1) Contracts are available for inspection upon request
(2) ANR feeds VGT.
(3) GLGT feeds NNG or VGT

ATTACHMENT 2

Northern States Power Company

Proposal for Entitlement Changes

**Information provided in response to the
Department letter dated October 1, 1993 and the
Commission Order dated October 16, 2015 in Docket No. G002/M-14-654**

PROPOSAL FOR ENTITLEMENT CHANGE
Department Format dated October 1, 1993

1 Provide a peak-day/design-day study by class for the twelve months ending one year from the proposed implementation date of the change(s):

See Attachment 1, Schedule 3.

2 Provide Heating Degree Day (HDD) data for the most recent twelve month period ending March 31 or September 30. This should include HDD, use per firm customer, and the peak season and off-peak HDD used for calculating the Company's design days:

See Attachment 1, Schedule 1, and Attachment 1, Schedule 4.

3 Historical and Projected Design-Day and Peak Demand Requirements:

Minnesota State

Heating Season[1] (1)	Number of Firm Customers[2] (2)	Design Day Requirement (Dth) (3)	Total Entitlement plus Storage plus Peak Shaving[3] (Dth) (4)	Peak Day Sendout (Dth) (5)	Heating Degree Days (6)	Actual Peak Day
Proposed: 2025/2026	496,663	786,332	835,043	TBD	TBD	TBD
2024/2025	493,367	784,382	825,735	635,749	66	12/12/2024
2023/2024	487,929	778,606	822,688	619,013	60	1/13/2024
2022/2023	482,452	774,448	817,990	764,743	72	12/23/2022
2021/2022	477,316	764,644	816,693	684,885	64	2/12/2022
2020/2021	469,356	750,974	792,448	743,767	76	2/14/2021
2019/2020	465,382	743,696	792,833	738,210	69	2/13/2020
2018/2019	461,078	735,741	779,864	735,822	75	1/29/2019
2017/2018	457,769	730,147	776,298	745,131	69	12/26/2017
2016/2017	454,396	725,225	765,534	733,711	66	1/5/2017
2015/2016	450,630	717,478	762,152	719,329	74	1/17/2016
2014/2015	446,409	715,945	761,354	687,501	64	1/12/2015
2013/2014	441,573	706,935	749,325	689,990	82	1/6/2014
2012/2013	439,210	702,159	745,247	689,747	71	1/21/2013
2011/2012	439,055	702,294	745,094	659,263	65	1/19/2012
2010/2011	436,594	699,611	743,781	675,667	69	1/20/2011
2009/2010	433,698	694,487	748,267	590,931	67	12/10/2009
2008/2009	428,852	685,005	732,291	601,425	78	1/15/2009
2007/2008	431,503	683,717	721,506	585,874	72	1/29/2008
2006/2007	424,415	677,733	696,257	568,963	67	2/2/2007
2005/2006	421,570	670,846	691,689	537,660	63	12/5/2005
2004/2005	410,986	649,655	675,120	537,374	60	1/5/2005

1 Per Annual Financial Reports.

2 Provide data and calculations for projected number of firm customers by class and in total corresponding to the design day requirement.

See Attachment 1, Schedule 1.

3 Total entitlement for Minnesota is calculated from the Proposed November 1 Entitlement.

See Attachment 1, Schedule 5.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

Northern States Power Company
COMPANY DEMAND PROFILE
2025-2026 Heating Season

Protected data is shaded.

Contract No.	Type of Capacity or Entitlement	Current Amount Dth or MMBtu	Proposed Change Dth or MMBtu	Proposed Amount Dth or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement	
	Capacity Entitlements							
112183	NNG TF12 BASE (Max)	104,117	0	104,117	10 yrs - 10/31/27		10.73%	
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%	
112182	NNG TF12 BASE (Disc)	24,201	4,172	28,373	10 yrs - 10/31/27	Annual Re-Determination	2.92%	
112182	NNG TF12 VARIABLE (Disc.)	70,326	(4,172)	66,154	10 yrs - 10/31/27	Annual Re-Determination	6.81%	
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		6.43%	
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.05%	
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 3/31/27		2.94%	
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27	Capacity Acquisition	5.99%	
112185	NNG TFX (Disc. 12-month)	36,654	11,613	48,267	10 yrs - 10/31/27		4.97%	
112185	NNG TFX 5 (Disc)	6,828	0	6,828	10 yrs - 10/31/27		Summer Only	
112185	NNG TFX 2 (Disc)	2,503	0	2,503	10 yrs - 10/31/27		Summer Only	
112186	NNG TFX 5 (Max)	28,132	1,157	29,289	10 yrs - 10/31/27	Capacity Acquisition	3.02%	
112186	NNG TFX 7 (Max)	22,707	1,157	23,864	10 yrs - 10/31/27	Capacity Acquisition	Summer Only	
112186	NNG TFX 5 (Disc Nov-Mar)	36,630	0	36,630	10 yrs - 10/31/27		3.77%	
112186	NNG TFX 5 (Disc Apr - Jun, Sep-Oct)	20,303	0	20,303	10 yrs - 10/31/27		Summer Only	
112186	NNG TFX 2 (Disc July-Aug)	1,000	0	1,000	10 yrs - 10/31/27		Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.58%	
122067	NNG TFX (Disc. Nov-Mar)	23,680	7,169	30,849	10 yrs - 10/31/27	Capacity Acquisition	3.18%	
122067	NNG TFX 7 (Disc)	23,680	7,169	30,849	10 yrs - 10/31/27	Capacity Acquisition	Summer Only	
122068	NNG TFX (Nov-Mar)	10,319	4,094	14,413	10 yrs - 10/31/27	Capacity Acquisition	1.48%	
122068	NNG TFX 7 (Max)	10,319	4,094	14,413	10 yrs - 10/31/27	Capacity Acquisition	Summer Only	
		[PROTECTED DATA BEGINS						
	VGT to NNG Chisago (1)							
	VGT Pierz to NNG (2)							
	Capacity Release							**PROTECTED DATA ENDS]**
AF0044	VGT FT-A 12 Mos.	32,405	0	32,405	5 yrs - 10/31/26		3.34%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/26		0.44%	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/29		1.03%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/27		1.61%	
AF0217	VGT FT-A 12 Mos.	87,213	0	87,213	5 yrs - 10/31/29		8.98%	
AF0329	VGT FT-A 12 Mos.	20,200	0	20,200	5 yrs - 10/31/28		2.08%	
AF0360	VGT FT-A 12 Mos.	22,000	0	22,000	5 yrs - 10/31/27		2.27%	
AF0535	VGT FT-A 12 Mos.	2,500	0	2,500	5 yrs - 11/30/28		0.26%	
AF0554	VGT FT-A 12 Mos.	30,000	0	30,000	5 yrs - 11/30/28		3.09%	
	WBI FT-1482	8,000	0	8,000	6.5 yrs - 3/30/2032		0.82%	
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%	
	City Gate Deliveries	20,000	0	20,000	3 yrs - 10/31/28		2.06%	
	TBD City Gate Deliveries	0	4,000	4,000	5 mth - 3/31/26		0.41%	
	LP Peak Shaving	90,000	0	90,000			9.27%	
	LNG Peak Shaving	156,000	0	156,000			16.07%	
	Total Design Day Capacity	**942,684**		**970,717**			**100%**	
	Heating Season Total	942,684		970,717				
	Non-Heating Season Total	555,147		579,180				

Miscellaneous Entitlements with Reservation Fees

Additional Pipeline Entitlements					
ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/27	
ANR FTS-106211 (Summer) (1)	5,433	2	5,435	3 yrs - 03/31/27	Annual Fuel Adjustment
ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/27	
ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	5 yrs - 10/31/28	
ANR FTS-135957 12 Mos. (1)	22,000	0	22,000	10 yrs - 10/31/32	
GLT FT18539 (Winter) (2)	3,509	0	3,509	13 yrs - 03/31/37	
GLT FT18539 (Summer) (2)	5,370	0	5,370	13 yrs - 03/31/37	
GLT Backhaul FT18129 (Nov-Mar) (2)	9,248	0	9,248	13 yrs - 03/31/37	
NNG SMS (3)	30,650		30,650	5 yrs - 10/31/27	
VGT OBA (3)	7,400		7,400	month-to-month	

Supply Entitlements (4)

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Storage Entitlements - Deliverability					
ANR Pipeline Storage	15,226	17	15,243	5 yrs - 3/31/29	Annual Fuel Adjustment
ANR Storage	9,248	0	9,248	6 yrs - 3/31/30	
FDD Service (5)	140,230	0	140,230	5 yrs - 5/31/27	
FDD Service	78,050	0	78,050	15 yrs - 5/31/27	
Storage Entitlements - Capacity					
ANR Pipeline Storage	944,012	1,054	945,066	5 yrs - 3/31/29	Annual Fuel Adjustment
ANR Storage Co	1,165,000	0	1,165,000	6 yrs - 3/31/30	
FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/27	
FDD Service	4,500,000	0	4,500,000	15 yrs - 5/31/27	

(1) Not included in total peak deliverability -- feeds VGT (capacity not additive).
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.
(5) Capacity expires 6,684,975 Dth in May 2027 & 1,400,000 Dth in May 2028.

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2025

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	942,684	28,033	970,717
Non-Heating Season	555,147	24,033	579,180
Heating Season Forecasted Design Day	907,591	6,500	914,092
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	35,093	21,533	56,625
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	3.9%	2.3%	6.2%
Total MN State Available Capacity:			
State of MN Allocation Factor	86.42%	-0.40%	86.02%
State of MN Heating Season Capacity	814,710	20,333	835,043
State of MN Design Day Demand	784,381	1,951	786,332
State of MN Heating Season Capacity Reserve/(Shortage)	30,329	18,382	48,711
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	3.9%	2.3%	6.2%

(1) Entitlement changes for November are included in Available Capacity.
Please reference Attachment 1 Schedule 5 for the detail on supply entitlement changes.

MINNESOTA STATE RATE IMPACT

Date to implement proposed changes: November 1, 2025
$/Dth

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: July 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$3.7517	$2.4880	$2.6006	$3.4419	-8.26%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$1.2458	$1.1571	$1.1656	$1.2800	2.75%	10.62%	9.81%	$0.1144
February Gas Event	$0.4219	$0.4219	$0.4219	$0.4219			0.00%	$0.0000
Distribution Margin	$3.8024	$2.7493	$3.8024	$3.8024	0.00%	38.31%	0.00%	$0.0000
Total per Dth Cost	$9.2218	$6.8163	$7.9905	$8.9462	-2.99%	31.25%	11.96%	$0.9557
Average Annual Usage (Dth)	84	84	84	84				
Average Annual Total Cost	$775.14	$572.95	$671.65	$751.98	-2.99%	31.25%	11.96%	$80.33
Average Annual Total Demand Cost of Gas	$104.72	$97.26	$97.98	$107.59				**$9.62**
Small Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.6006	$3.4419	-7.41%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$1.2629	$1.1651	$1.1815	$1.2961	2.63%	11.24%	9.70%	$0.1146
Distribution Margin	$3.1143	$2.1974	$3.1143	$3.1143	0.00%	41.73%	0.00%	$0.0000
Total per Dth Cost	$8.0945	$5.8505	$6.8964	$7.8523	-2.99%	34.22%	13.86%	$0.9559
Average Annual Usage (Dth)	224	224	224	224				
Average Annual Total Cost	$1,815.84	$1,312.44	$1,547.07	$1,761.50	-2.99%	34.22%	13.86%	$214.44
Average Annual Total Demand Cost of Gas	$283.31	$261.37	$265.05	$290.76				**$25.71**
Large Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.6006	$3.4419	-7.41%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$1.2188	$1.1344	$1.1435	$1.2547	2.95%	10.60%	9.72%	$0.1112
Distribution Margin	$2.7255	$1.8410	$2.7255	$2.7255	0.00%	48.04%	0.00%	$0.0000
Total per Dth Cost	$7.6616	$5.4634	$6.4696	$7.4221	-3.13%	35.85%	14.72%	$0.9525
Average Annual Usage (Dth)	1,591	1,591	1,591	1,591				
Average Annual Total Cost	$12,192.19	$8,694.14	$10,295.28	$11,811.03	-3.13%	35.85%	14.72%	$1,515.75
Average Annual Total Demand Cost of Gas	$1,939.52	$1,805.21	$1,819.70	$1,996.65				**$176.96**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: July 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.6006	$3.4419	-7.34%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$2.2037	$1.4885	$2.2037	$2.2037	0.00%	48.05%	0.00%	$0.0000
Total per Dth Cost	$5.9182	$3.9765	$4.8043	$5.6456	-4.61%	41.97%	17.51%	$0.8413
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$49,938.43	$33,553.70	$40,538.66	$47,637.61	-4.61%	41.97%	17.51%	$7,098.96
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.6006	$3.4419	-5.93%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.5414	$0.8478	$1.5414	$1.5414	0.00%	81.82%	0.00%	$0.0000
Total per Dth Cost	$5.2004	$3.3358	$4.1420	$4.9833	-4.18%	49.39%	20.31%	$0.8413
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$280,617.56	$179,998.93	$223,503.54	$268,900.56	-4.18%	49.39%	20.31%	$45,397.02
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.6006	$3.4419	-4.77%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.3629	$0.7977	$1.3629	$1.3629	0.00%	70.87%	0.00%	$0.0000
Total per Dth Cost	$4.9772	$3.2857	$3.9635	$4.8048	-3.46%	46.24%	21.23%	$0.8413
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,360,143.69	$2,218,170.52	$2,675,813.12	$3,243,781.97	-3.46%	46.24%	21.23%	$567,968.85
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: July 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.6006	$3.4419	-7.34%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.9833	$0.0000	$1.9833	$2.2037	11.11%	0.00%	11.11%	$0.2204
Total per Dth Cost	$5.6979	$2.4880	$4.5839	$5.6456	-0.92%	126.91%	23.16%	$1.0617
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$48,079.01	$20,993.95	$38,679.24	$47,637.61	-0.92%	126.91%	23.16%	$8,958.37
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.6006	$3.4419	-5.93%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.3872	$0.0000	$1.3872	$1.3872	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.0463	$2.4880	$3.9878	$4.8291	-4.30%	94.10%	21.10%	$0.8413
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$272,300.08	$134,253.86	$215,186.06	$260,583.08	-4.30%	94.10%	21.10%	$45,397.02
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.6006	$3.4419	-4.77%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.2266	$0.0000	$1.2266	$1.3629	11.11%	0.00%	11.11%	$0.1363
Total per Dth Cost	$4.8409	$2.4880	$3.8272	$4.8048	-0.75%	93.12%	25.54%	$0.9776
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,268,133.14	$1,679,670.15	$2,583,802.57	$3,243,781.97	-0.75%	93.12%	25.54%	$659,979.40
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.8413	32.35%	$0.1144	9.81%	$9.62	$80.33	11.96%
Small Commercial	$0.8413	32.35%	$0.1146	9.70%	$25.71	$214.44	13.86%
Large Commercial	$0.8413	32.35%	$0.1112	9.72%	$176.96	$1,515.75	14.72%
Small Interruptible Tier I	$0.8413	32.35%	$0.0000	NA	$0.00	$7,098.96	17.51%
Small Interruptible Tier II	$0.8413	32.35%	$0.0000	NA	$0.00	$8,958.37	23.16%
Medium Interruptible Tier I	$0.8413	32.35%	$0.0000	NA	$0.00	$45,397.02	20.31%
Medium Interruptible Tier II	$0.8413	32.35%	$0.0000	NA	$0.00	$45,397.02	21.10%
Large Interruptible Tier I	$0.8413	32.35%	$0.0000	NA	$0.00	$567,968.85	21.23%
Large Interruptible Tier II	$0.8413	32.35%	$0.0000	NA	$0.00	$659,979.40	25.54%

DERIVATION OF CURRENT PGA COSTS

Nov. 2025 - Projected Costs (Actual prices will be determined Nov. 1, 2025)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$56,966,198	$38,057,544	
2.	x Minnesota Design Day Ratio (2025 Demand Entitlement Filing)	86.02%	86.02%	
3.	Annual System Demand Allocation to MN	$49,002,323	$32,737,099	
4.	MN State Design Day (2025 Demand Entitlement Filing)	786,332	786,332	
5.	- Small & Large Demand Billed Dth (2024 Demand Entitlement Filing)	28,540	28,540	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	757,792	757,792	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$47,223,779	$31,548,903	
8.	Demand Billed Cost Allocation (3 - 7)	$1,778,544	$1,188,196	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	618,290,026	465,570,166	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.07638	$0.06776	$0.14414
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.14414
14.	Total Demand Rate -Commercial (10 + 12)			$0.14414
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$1,778,544	$1,188,196	$2,966,740
16.	/ Annual Contract Billing Demand (2025 Demand Entitlement Filing)			3,424,800
17.	Monthly Commercial Demand Billed Demand Rate			$0.86625

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$31,632,988
19.	x MN Portion of Monthly Retail Sales	84.37%
20.	MN Portion of Monthly Commodity Costs	$26,688,752
21.	MN Budgeted Calendar Month Retail Therm Sales	77,539,814
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.34419

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.48833**
24.	Small & Large Commercial (14 +22)	**$0.48833**
25.	Small & Large Demand Billed - Demand (17)	**$0.86625**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.34419**

*Commodity costs are projected and for illustrative purposed only.

ATTACHMENT 3

Northern States Power Company

Information provided in response to reporting requirements in Docket No. G002/M-08-46 (Order dated May 27, 2008) Regarding use of financial instruments to limit price volatility and Docket Nos. G002/M-16-88 (Order dated April 22, 2016), G002/M-19-703 (Order dated February 12, 2020), and G002/M-23-521 (Order dated May 21, 2024) regarding benefits of the contracts.

Order Point 2 of the Commission's April 22, 2016 Order in Docket No. G002/M-16-88,

Order Point 6b of the Commission's February 12, 2020 Order in Docket No. G002/M-19-703, and

Order Point 5b of the Commission's May 21, 2024 Order in Docket No. G002/M-23-521 require the following:

> *Include, in its requests for approval of changes in demand entitlements submitted on approximately August 1 of each year, a list of all financial instrument arrangements entered into for the upcoming heating season, including the cost premium associated with each contract, the size of each contract, contract date, contract price, and an explanation of the anticipated benefits of these contract to Xcel's ratepayers.*

The overall anticipated benefit of the Company's Price Volatility Mitigation Plan, is to reduce our customers' exposure to, and the magnitude of First of Month (FOM) gas price spike events at a reasonable cost. The goal of the plan is not to attempt to outguess the market or to speculate on the future direction of energy prices. In the development and implementation to the Plan, the Company realizes that the final result of our efforts may be higher prices than purchasing all gas supply on the monthly spot market. However, the Company maintains that price volatility mitigation is important in order to protect the Company and our customers from the risk of very high gas prices due to unforeseeable market conditions and/or events.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
SUMMARY OF COMPANY HEDGE TRANSACTIONS
2025-2026 Heating Season

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
Attachment 3, Schedule 1

Protected data is shaded.

Transaction Date	Hedge Instrument	Counterparty	Premium ($/Dth)	Call Strike Price	Put Strike Price	Daily Vol (Dth)	Basis Point	Monthly Volumes (Dth)					Total Volume (Dth)	Total Dollars
								November	December	January	February	March		

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Attachments
Effective January 1, 2026

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

DEMAND COST OF GAS IMPACT - JANUARY 2026

Protected data is shaded.

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5	$ (499,763.08)
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5	$ 795,476.21
ANR FTS-1 (Nov-Mar)	(5,433)	$ 6.5884	7	$ (250,563.44)
ANR FTS-1 (Nov-Mar)	5,433	$ 10.4868	7	$ 398,823.49
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62
ANR FTS-1 (Nov-Oct)	(15,226)	$ 2.1126	12	$ (385,997.37)
ANR FTS-1 (Nov-Oct)	15,226	$ 2.5372	12	$ 463,576.89
ANR FSS (Nov-Oct)	17	$ 2.5372	12	$ 517.59
ANR FSS (Jan-Dec)	(9,248)	$ 1.4160	5	$ (65,475.84)
ANR FSS (Jan-Dec)	9,248	$ 3.4645	5	$ 160,198.48
ANRS FSS (Apr-July)	2	$ 10.4868	7	$ 146.82
ANRS FSS (Apr-July)	1,157	$ 25.7990	2	$ 59,698.89
ANR FTS-1 (Apr-July)	1,157	$ 47.7400	3	$ 165,705.54
NNG TFX (Nov-Dec)	1,157	$ 17.9030	7	$ 144,996.40
NNG TFX (Jan-Mar)	4,094	$ 25.7990	2	$ 211,242.21
NNG TFX (Nov-Dec)	4,094	$ 47.7400	3	$ 586,342.68
NNG TFX (Jan-Mar)	4,094	$ 17.9030	7	$ 513,064.17
NNG TFX (Apr-Oct)	(28,500)	$ 25.7990	3	$ (2,205,814.50)
NNG TFX (Jan-Mar)	28,500	$ 47.7400	3	$ 4,081,770.00
NNG TFX (Jan-Mar)	(10,319)	$ 25.7990	3	$ (798,659.64)
NNG TFX (Jan-Mar)	10,319	$ 47.7400	3	$ 1,477,887.18
NNG TFX (Jan-Mar)	(10,319)	$ 9.6760	7	$ (698,926.51)
NNG TFX (Apr-Oct)	10,319	$ 17.9030	7	$ 1,293,187.40
NNG TFX (Apr-Oct)	(28,132)	$ 25.7990	3	$ (2,177,332.40)
NNG TFX (Jan-Mar)	28,132	$ 47.7400	3	$ 4,029,065.04
NNG TFX (Jan-Mar)	(22,707)	$ 9.6760	7	$ (1,537,990.52)
NNG TFX (Apr-Oct)	22,707	$ 17.9030	7	$ 2,845,663.95
NNG TFX (Apr-Oct)	(140,230)	$ 3.2345	10	$ (4,535,739.35)
NNG FDD (Jan-Oct)	(78,050)	$ 3.2345	10	$ (2,524,527.25)
NNG FDD (Jan-Oct)	140,230	$ 4.8003	10	$ 6,731,460.69
NNG FDD (Jan-Oct)	78,050	$ 4.8003	10	$ 3,746,634.15
		[PROTECTED DATA BEGINS		
NNG TFX (Nov-Oct)	6,667			
NNG TFX (Nov-Oct)	3,333			
NNG TFX (Nov-Oct)	3,333			
NNG TFX (Nov-Oct)	1,613			
NNG TFX (Nov-Oct)	1,613			
NNG TFX (Nov-Oct)	7,169			
NNG TFX (Nov-Oct)	7,169			
				PROTECTED DATA ENDS]
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5	$ (143,623.37)
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5	$ 160,045.49
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5	$ (378,520.64)
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5	$ 421,801.28
Total				$ 18,194,602.04

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

		PROTECTED DATA ENDS]
Total	4,000	$ 412,627.00
Total MN & ND Demand Cost Adjustment		**$ 18,607,229.04**
Minnesota Allocation Factor (MN/ND Allocated Demand)		86.02%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 16,006,556.55**

[1]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v.4.0.1 Effective November 1, 2025
[2]GLGT Volume No. 1, Part 5.0 - Statement of Rates, v.60.0.0, Effective Novemeber 1, 2025
3NNG Seventh Revised Volume No. 1, Twenty First Revised Sheet No. 50, Effective January 1, 2026
4NNG Seventh Revised Volume No. 1, Twenty Fourth Revised Sheet No. 51, Effective January 1, 2026

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
Attachment 1, Schedule 2

Protected data is shaded.

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2024 SUPPLEMENTAL FILED COSTS				**$50,970,508.65**	**$35,820,718.55**	**$86,791,227.20**				
2024 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2024 ACTUAL COSTS				**$ 50,970,508.65**	**$ 35,820,718.55**	**$ 86,791,227.20**				
CHANGES FOR 2025 FILING										
Contract Demand Entitlement Changes										
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)		$ (5,257,543.20)			$ (5,257,543.20)	1
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40		$ 8,368,466.40			$ 8,368,466.40	1
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5		$ (499,763.08)	$ (499,763.08)			$ (499,763.08)	1
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5		$ 795,476.21	$ 795,476.21			$ 795,476.21	1
ANR FTS-1 (Apr-July)	(5,433)	$ 6.5884	7		$ (250,563.44)	$ (250,563.44)			$ (250,563.44)	1
ANR FTS-1 (Apr-July)	5,433	$ 10.4868	7		$ 398,823.49	$ 398,823.49			$ 398,823.49	1
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)		$ (1,739,337.60)			$ (1,739,337.60)	1
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20		$ 2,768,515.20			$ 2,768,515.20	1
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)		$ (816,487.32)			$ (816,487.32)	1
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62		$ 1,564,352.62			$ 1,564,352.62	1
ANR FSS (Nov-Oct)	(15,226)	$ 2.1126	12		$ (385,997.37)	$ (385,997.37)			$ (385,997.37)	1
ANR FSS (Jan-Dec)	15,226	$ 2.5372	12		$ 463,576.89	$ 463,576.89			$ 463,576.89	1
ANR FSS (Jan-Dec)	17	$ 2.5372	12		$ 517.59	$ 517.59			$ 517.59	1
ANRS FSS (Apr-July)	(9,248)	$ 1.4160	5		$ (65,475.84)	$ (65,475.84)			$ (65,475.84)	1
ANRS FSS (Apr-July)	9,248	$ 3.4645	5		$ 160,198.48	$ 160,198.48			$ 160,198.48	1
ANR FTS-1 (Apr-July)	2	$ 10.4868	7		$ 146.82	$ 146.82			$ 146.82	1
NNG TFX (Nov-Dec)	1,157	$ 25.7990	2		$ 59,698.89	$ 59,698.89	$ 59,698.89			5
NNG TFX (Jan-Mar)	1,157	$ 47.7400	3		$ 165,705.54	$ 165,705.54	$ 165,705.54			5
NNG TFX (Apr-Oct)	1,157	$ 17.9030	7	$ 144,996.40		$ 144,996.40	$ 144,996.40			5
NNG TFX (Nov-Dec)	4,094	$ 25.7990	2		$ 211,242.21	$ 211,242.21	$ 211,242.21			5
NNG TFX (Jan-Mar)	4,094	$ 47.7400	3		$ 586,342.68	$ 586,342.68	$ 586,342.68			5
NNG TFX (Apr-Oct)	4,094	$ 17.9030	7	$ 513,064.17		$ 513,064.17				5
NNG TFX (Jan-Mar)	(28,500)	$ 25.7990	3		$ (2,205,814.50)	$ (2,205,814.50)				7
NNG TFX (Jan-Mar)	28,500	$ 47.7400	3		$ 4,081,770.00	$ 4,081,770.00				7
NNG TFX (Jan-Mar)	(10,319)	$ 25.7990	3		$ (798,659.64)	$ (798,659.64)				7
NNG TFX (Jan-Mar)	10,319	$ 47.7400	3		$ 1,477,887.18	$ 1,477,887.18				7
NNG TFX (Apr-Oct)	(10,319)	$ 9.6760	7	$ (698,926.51)		$ (698,926.51)				7
NNG TFX (Apr-Oct)	10,319	$ 17.9030	7	$ 1,293,187.40		$ 1,293,187.40				7
NNG TFX (Jan-Mar)	(28,132)	$ 25.7990	3		$ (2,177,332.40)	$ (2,177,332.40)				7
NNG TFX (Jan-Mar)	28,132	$ 47.7400	3		$ 4,029,065.04	$ 4,029,065.04				7
NNG TFX (Apr-Oct)	(22,707)	$ 9.6760	7	$ (1,537,990.52)		$ (1,537,990.52)				7
NNG TFX (Apr-Oct)	22,707	$ 17.9030	7	$ 2,845,663.95		$ 2,845,663.95				7
NNG FDD (Jan-Oct)	(140,230)	$ 3.2345	10		$ (4,535,739.35)	$ (4,535,739.35)				7
NNG FDD (Jan-Oct)	(78,050)	$ 3.2345	10		$ (2,524,527.25)	$ (2,524,527.25)				7
NNG FDD (Jan-Oct)	140,230	$ 4.8003	10		$ 6,731,460.69	$ 6,731,460.69				7
NNG FDD (Jan-Oct)	78,050	$ 4.8003	10		$ 3,746,634.15	$ 3,746,634.15				7
		[PROTECTED DATA BEGINS								
NNG TFX (Nov-Oct)	6,667									5
NNG TFX (Nov-Oct)	3,333									5
NNG TFX (Nov-Oct)	3,333									5
NNG TFX (Nov-Oct)	1,613									5
NNG TFX (Nov-Oct)	1,613									5
NNG TFX (Nov-Oct)	7,169									5
NNG TFX (Nov-Oct)	7,169									5
						PROTECTED DATA ENDS]				
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5		$ (143,623.37)	$ (143,623.37)		$ (143,623.37)		6
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5		$ 160,045.49	$ 160,045.49		$ 160,045.49		6
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)		$ (307,711.74)		$ (307,711.74)		6
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98		$ 342,895.98		$ 342,895.98		6
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5		$ (378,520.64)	$ (378,520.64)		$ (378,520.64)		6
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5		$ 421,801.28	$ 421,801.28		$ 421,801.28		6
Total				$ 8,200,023.23	$ 9,994,578.84	$ 18,194,602.07	$ 2,355,066.81	$ 94,887.00	$ 5,504,905.85	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										8
										8
										8
										8
										8
									PROTECTED DATA ENDS]	
Total				$0.00	$412,627.00	$412,627.00	$0.00	$412,627.00	$0.00	
TOTAL OF 2025 CHANGES				**$ 8,200,023.23**	**$ 10,407,205.84**	**$ 18,607,229.07**	**$ 2,355,066.81**	**$ 507,514.00**	**$ 5,504,905.85**	
2025 COSTS				**$ 59,170,531.88**	**$ 46,227,924.39**	**$ 105,398,456.27**				
2025 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							82%	18%		9

Footnote
1. Rate change in accordnace with approved Rate Case Settlement (RP25-858), Rate effective November 1, 2025.
2. Contract renewal at maximum tariff rate.
3. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
4. Rate change as a result of applying discount agreements
5. Acquisition of new capacity on NNG as part of Northern Lights 2025 to meet Design Day requirements of Minnesota customers.
6. Rate change due to ongoing Rate Case (RP25-855), Interim Settlement Rates effective November 1, 2025.
7. Rate change due to ongoing Rate Case (RP25-989), Interim Settlement Rates effective January 1, 2026
8. Expired/Replaced peaking supply contract with demand charges in effect November 1, 2025 through March 31, 2026.
9. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purpocses of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

Date to implement proposed changes: January 1, 2026
$/Dth

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: July 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$3.7517	$2.4880	$2.6006	$3.4419	-8.26%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$1.2458	$1.1571	$1.1656	$1.4203	14.01%	22.75%	21.85%	$0.2547
February Gas Event	$0.4219	$0.4219	$0.4219	$0.4219			0.00%	$0.0000
Distribution Margin	$3.8024	$2.7493	$3.8024	$3.8024	0.00%	38.31%	0.00%	$0.0000
Total per Dth Cost	$9.2218	$6.8163	$7.9905	$9.0865	-1.47%	33.31%	13.72%	$1.0960
Average Annual Usage (Dth)	84	84	84	84				
Average Annual Total Cost	$775.14	$572.95	$671.65	$763.77	-1.47%	33.31%	13.72%	$92.13
Average Annual Total Demand Cost of Gas	$104.72	$97.26	$97.98	$119.38				**$21.41**
Small Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.6006	$3.4419	-7.41%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$1.2629	$1.1651	$1.1815	$1.4399	14.02%	23.59%	21.87%	$0.2584
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$3.1143	$2.1974	$3.1143	$3.1143	0.00%	41.73%	0.00%	$0.0000
Total per Dth Cost	$8.0945	$5.8505	$6.8964	$7.9961	-1.22%	36.67%	15.95%	$1.0997
Average Annual Usage (Dth)	224	224	224	224				
Average Annual Total Cost	$1,815.84	$1,312.44	$1,547.07	$1,793.76	-1.22%	36.67%	15.95%	$246.70
Average Annual Total Demand Cost of Gas	$283.31	$261.37	$265.05	$323.01				**$57.97**
Large Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.6006	$3.4419	-7.41%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$1.2188	$1.1344	$1.1435	$1.3896	14.01%	22.50%	21.52%	$0.2461
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$2.7255	$1.8410	$2.7255	$2.7255	0.00%	48.04%	0.00%	$0.0000
Total per Dth Cost	$7.6616	$5.4634	$6.4696	$7.5570	-1.37%	38.32%	16.81%	$1.0874
Average Annual Usage (Dth)	1,591	1,591	1,591	1,591				
Average Annual Total Cost	$12,192.19	$8,694.14	$10,295.28	$12,025.70	-1.37%	38.32%	16.81%	$1,730.42
Average Annual Total Demand Cost of Gas	$1,939.52	$1,805.21	$1,819.70	$2,211.32				**$391.63**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: July 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.6006	$3.4419	-7.34%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$2.2037	$1.4885	$2.2037	$2.2037	0.00%	48.05%	0.00%	$0.0000
Total per Dth Cost	$5.9182	$3.9765	$4.8043	$5.6456	-4.61%	41.97%	17.51%	$0.8413
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$49,938.43	$33,553.70	$40,538.66	$47,637.61	-4.61%	41.97%	17.51%	$7,098.96
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.6006	$3.4419	-5.93%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.5414	$0.8478	$1.5414	$1.5414	0.00%	81.82%	0.00%	$0.0000
Total per Dth Cost	$5.2004	$3.3358	$4.1420	$4.9833	-4.18%	49.39%	20.31%	$0.8413
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$280,617.56	$179,998.93	$223,503.54	$268,900.56	-4.18%	49.39%	20.31%	$45,397.02
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.6006	$3.4419	-4.77%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.3629	$0.7977	$1.3629	$1.3629	0.00%	70.87%	0.00%	$0.0000
Total per Dth Cost	$4.9772	$3.2857	$3.9635	$4.8048	-3.46%	46.24%	21.23%	$0.8413
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,360,143.69	$2,218,170.52	$2,675,813.12	$3,243,781.97	-3.46%	46.24%	21.23%	$567,968.85
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: July 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.6006	$3.4419	-7.34%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.9833	$0.0000	$1.9833	$2.2037	11.11%	0.00%	11.11%	$0.2204
Total per Dth Cost	$5.6979	$2.4880	$4.5839	$5.6456	-0.92%	126.91%	23.16%	$1.0617
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$48,079.01	$20,993.95	$38,679.24	$47,637.61	-0.92%	126.91%	23.16%	$8,958.37
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.6006	$3.4419	-5.93%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.3872	$0.0000	$1.3872	$1.3872	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.0463	$2.4880	$3.9878	$4.8291	-4.30%	94.10%	21.10%	$0.8413
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$272,300.08	$134,253.86	$215,186.06	$260,583.08	-4.30%	94.10%	21.10%	$45,397.02
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.6006	$3.4419	-4.77%	38.34%	32.35%	$0.8413
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.2266	$0.0000	$1.2266	$1.3629	11.11%	0.00%	11.11%	$0.1363
Total per Dth Cost	$4.8409	$2.4880	$3.8272	$4.8048	-0.75%	93.12%	25.54%	$0.9776
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,268,133.14	$1,679,670.15	$2,583,802.57	$3,243,781.97	-0.75%	93.12%	25.54%	$659,979.40
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.8413	32.35%	$0.2547	21.85%	$21.41	$92.13	13.72%
Small Commercial	$0.8413	32.35%	$0.2584	21.87%	$57.97	$246.70	15.95%
Large Commercial	$0.8413	32.35%	$0.2461	21.52%	$391.63	$1,730.42	16.81%
Small Interruptible Tier I	$0.8413	32.35%	$0.0000	NA	$0.00	$7,098.96	17.51%
Small Interruptible Tier II	$0.8413	32.35%	$0.0000	NA	$0.00	$8,958.37	23.16%
Medium Interruptible Tier I	$0.8413	32.35%	$0.0000	NA	$0.00	$45,397.02	20.31%
Medium Interruptible Tier II	$0.8413	32.35%	$0.0000	NA	$0.00	$45,397.02	21.10%
Large Interruptible Tier I	$0.8413	32.35%	$0.0000	NA	$0.00	$567,968.85	21.23%
Large Interruptible Tier II	$0.8413	32.35%	$0.0000	NA	$0.00	$659,979.40	25.54%

DERIVATION OF CURRENT PGA COSTS

Jan 2026 - Projected Costs (Actual prices will be determined Jan. 1, 2026)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$59,170,532	$46,227,924	
2.	x Minnesota Design Day Ratio (2025 Demand Entitlement Filing)	86.02%	86.02%	
3.	Annual System Demand Allocation to MN	$50,898,492	$39,765,261	
4.	MN State Design Day (2025 Demand Entitlement Filing)	786,332	786,332	
5.	- Small & Large Demand Billed Dth (2024 Demand Entitlement Filing)	28,540	28,540	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	757,792	757,792	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$49,051,126	$38,321,977	
8.	Demand Billed Cost Allocation (3 - 7)	$1,847,366	$1,443,284	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	618,290,026	465,570,166	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.07933	$0.08231	$0.16164
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.16164
14.	Total Demand Rate -Commercial (10 + 12)			$0.16164
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$1,847,366	$1,443,284	$3,290,650
16.	/ Annual Contract Billing Demand (2025 Demand Entitlement Filing)			3,424,800
17.	Monthly Commercial Demand Billed Demand Rate			$0.96083

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$31,632,988
19.	x MN Portion of Monthly Retail Sales	84.37%
20.	MN Portion of Monthly Commodity Costs	$26,688,752
21.	MN Budgeted Calendar Month Retail Therm Sales	77,539,814
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.34419

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.50583**
24.	Small & Large Commercial (14 +22)	**$0.50583**
25.	Small & Large Demand Billed - Demand (17)	**$0.96083**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.34419**

*Commodity costs are projected and for illustrative purposed only.

CERTIFICATE OF SERVICE

I, Joshua DePauw, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NOS. **G002/GR-23-413**
G002/GR-21-678
Xcel Energy Misc. Gas Service List

Dated this 1st day of August 2025

/s/
____
Joshua DePauw
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Lane PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	23-413Official
2	Katherine	Arnold	katherine.arnold@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	23-413Official
3	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	23-413Official
4	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	23-413Official
5	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
6	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	23-413Official
7	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	23-413Official
8	Robert S.	Carney, Jr.				4232 Colfax Ave. S. Minneapolis MN, 55409 United States	Paper Service		No	23-413Official
9	Olivia	Carroll	oliviac@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St W1360 St. Paul MN, 55101 United States	Electronic Service		No	23-413Official
10	Joey	Cherney	joey.cherney@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street STE 1800 Saint Paul MN, 55101 United States	Electronic Service		No	23-413Official
11	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	23-413Official
12	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	23-413Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
13	Brandon	Crawford	brandonc@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 St. Paul MN, 55101 United States	Electronic Service		No	23-413Official
14	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	23-413Official
15	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	23-413Official
16	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	23-413Official
17	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	23-413Official
18	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	23-413Official
19	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	23-413Official
20	Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP		Suite 1750 220 South Sixth Street Minneapolis MN, 55402-1425 United States	Electronic Service		No	23-413Official
21	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	23-413Official
22	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	23-413Official
23	Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S. Eighth Street Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
24	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	23-413Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
25	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	23-413Official
26	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
27	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
28	Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	23-413Official
29	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	23-413Official
30	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	23-413Official
31	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164-0620 United States	Electronic Service		No	23-413Official
32	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	23-413Official
33	Stephen	Melchionne	stephen.melchionne@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street, Ste. 1400 St. Paul MN, 55101 United States	Electronic Service		No	23-413Official
34	Kimberly	Middendorf	kimberly.middendorf@state.mn.us		Office of Administrative Hearings	PO Box 64620 600 Robert St N Saint Paul MN, 55164-0620 United States	Electronic Service		No	23-413Official
35	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	23-413Official
36	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
37	Travis	Murray	travis.murray@ag.state.mn.us		Office of the Attorney General -	445 Minnesota St Ste 1400	Electronic Service		No	23-413Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
					Residential Utilities Division	Saint Paul MN, 55101 United States				
38	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
39	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	23-413Official
40	Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	23-413Official
41	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	23-413Official
42	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	23-413Official
43	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
44	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.		225 South Sixth Street Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
45	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	23-413Official
46	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	23-413Official
47	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		No	23-413Official
48	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official
49	Suzanne	Todnem	suzanne.todnem@state.mn.us		Office of Administrative Hearings	600 Robert St N PO Box 64620	Electronic Service		Yes	23-413Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						St. Paul MN, 55164 United States				
50	Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 St. Paul MN, 55104 United States	Electronic Service		No	23-413Official
51	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	23-413Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Lane PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	21-67821-678
2	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	21-67821-678
3	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-67821-678
4	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
5	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	21-67821-678
6	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	21-67821-678
7	Robert S.	Carney, Jr.				4232 Colfax Ave. S. Minneapolis MN, 55409 United States	Paper Service		No	21-67821-678
8	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	21-67821-678
9	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	21-67821-678
10	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	21-67821-678
11	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	21-67821-678
12	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-67821-678

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
13	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	21-67821-678
14	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	21-67821-678
15	Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP		Suite 1750 220 South Sixth Street Minneapolis MN, 55402-1425 United States	Electronic Service		No	21-67821-678
16	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	21-67821-678
17	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	21-67821-678
18	Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S. Eighth Street Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
19	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	21-67821-678
20	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	21-67821-678
21	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
22	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
23	Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	21-67821-678
24	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	21-67821-678
25	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN,	Electronic Service		Yes	21-67821-678

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55164-0620 United States				
26	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-67821-678
27	Greg	Merz	greg.merz@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	21-67821-678
28	Joseph	Meyer	joseph.meyer@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Bremer Tower, Suite 1400 445 Minnesota Street St Paul MN, 55101-2131 United States	Electronic Service		No	21-67821-678
29	Kimberly	Middendorf	kimberly.middendorf@state.mn.us		Office of Administrative Hearings	PO Box 64620 600 Robert St N Saint Paul MN, 55164-0620 United States	Electronic Service		No	21-67821-678
30	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	21-67821-678
31	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
32	Travis	Murray	travis.murray@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Ste 1400 Saint Paul MN, 55101 United States	Electronic Service		No	21-67821-678
33	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
34	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	21-67821-678
35	Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	21-67821-678
36	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	21-67821-678
37	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
38	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.		225 South Sixth Street Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
39	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	21-67821-678
40	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		No	21-67821-678
41	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678
42	Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 St. Paul MN, 55104 United States	Electronic Service		No	21-67821-678
43	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	21-67821-678

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
2	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
3	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
4	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
5	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
6	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
7	Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP		Suite 1750 220 South Sixth Street Minneapolis MN, 55402-1425 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
8	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
9	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
10	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
11	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
12	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
13	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
14	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
15	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
16	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
17	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas
18	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-GasXcel Miscl Gas