414 Nicollet Mall
Minneapolis, Minnesota 55401

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July 31, 2020

—Via Electronic Filing—

Will Seuffert
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. G002/M-20-___

Dear Mr. Seuffert:

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.

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 Jennifer Roesler at (612) 330-1925 or jennifer.roesler@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	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-20-___ **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 PGA, changes in our interstate pipeline transportation, storage entitlements, and other demand-related contracts for the upcoming year. We have projected an increase in Minnesota design day requirements of 5,496 Dekatherms, with a decrease in demand related costs of approximately $5,287,928 (or -7%) for the 2020-2021 year. The change is predominantly the result of settlements in rate proceedings with both Northern Natural Gas and Viking Gas Transmission, which are pending approval by the Federal Energy Regulatory Commission. 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 2020-2021 Heating Season Supply Plan effective November 1, 2020, 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, 2020.

The following attachments are included with this Petition:

- Attachment 1: Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2.
- 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. SUMMARY OF FILING

A one-paragraph summary of the filing accompanies this Petition pursuant to Minnesota 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 (2009 and 2006) 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, Xcel Energy provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

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

James R. Denniston
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
(612) 215-4656

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on July 31, 2020. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2020 usage. Pursuant to Minn. Stat. § 216B.16, Subd. 7, Minn. Rule 7825.2920, and our Purchased Gas Adjustment tariff (Minnesota Gas Rate Book Sheet Nos. 5-40, revision 2; 5-41, revision 7; 5-42, revision 3), Xcel Energy will provisionally place the PGA changes into effect on November 1, 2020, 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. Rules 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
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minnesota Rule 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

James R. Denniston
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
james.r.denniston@xcelenergy.com

Lynnette Sweet
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 Lynnette Sweet at the Regulatory Records email address above.

V. 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 Design Day (DD) conditions. By comparing that anticipated need to our current supply arrangements, we can determine what incremental additions are needed to ensure 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, 2020, and respectfully request Commission approval of the revised entitlements effective on November 1, 2020. 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 2019-2020 heating season, as described in Attachment 1, Page 3. Our forecasted firm customer count in Minnesota State increased by 3,968 customers, from 465,382 forecast for the 2019-2020 heating season to 469,350 forecast for the 2020-2021 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 5,496 Dekatherms (Dth), from 743,696 to 749,192.

B. Change in Resources to meet Design Day

Reflected in this filing are 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,[1] and outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, pipeline billing units and storage entitlements from the 2019-2020 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. The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 87.57 percent to 87.18 percent.

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

D. Change in Supply Reservation Fees

This filing also reflects updated costs for firm gas supply reservation fees. The total change in supplier reservation charges is an increase of $88,166.

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 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 attachment discusses the anticipated benefits of the contracts to ratepayers and shows a summary of hedge transactions for the 2020-2021 heating season.

F. Reserve Margin Information

We propose a capacity reserve margin of 5.7 percent for the 2020-2021 heating season, as discussed in Attachment 1, section C and Attachment 2, Schedule 1, Page 3 of 3.

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

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.

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

VI. 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 a decrease of $5,287,928 or about 7 percent of the total Minnesota State demand costs, effective November 1, 2020. 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 2020-2021 Heating Season Supply Plan effective November 1, 2021, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2020 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: July 31, 2020

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	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-20-___

PETITION

SUMMARY OF FILING

Please take notice that on July 31, 2020, Northern States Power Company, doing business as Xcel Energy, filed a Request for Change in Contract Demand Entitlements pursuant to Minnesota Rule 7825.2910, Subp. 2. Xcel Energy requests Commission approval to implement its 2020-2021 Heating Season Supply Plan effective November 1, 2020. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2020, subject to later Commission approval.

ATTACHMENT 1

Northern States Power Company

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

Northern States Power Company

Filing Requirements Pursuant to Minnesota 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.

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

Our forecasted firm customer count in Minnesota State increased by 3,968 customers, from 465,382 forecast for the 2019-2020 heating season to 469,350 forecast for the 2020-2021 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 5,496 Dekatherms (Dth), from 743,696 to 749,192, 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 60 data points, from January 2015-December 2019, as shown on **Attachment 1, Schedule 1, Pages 2-5**. Nearly 82% 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 last year, three areas (Grand Forks MN Small Commercial (GFMSC), Fargo MN Residential (FGMR), and WBI Residential (WBIR)) resulted in negative intercept coefficients. This would indicate negative gas use at 0 HDD, which is not realistically possible. To correct this, we adjusted the heating degree day values to 0 for each summer month for the affected areas. 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 three areas, 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 no Durbin-Watson results substantially over 2, and eleven regressions with values below 1, indicating positive autocorrelation. In other words, the previous error predicted the following error term.

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

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 1 time-span with the estimate of the autocorrelation effect. The regression analysis is then performed on the transformed data. In using a standard Ordinary Least Squares model, the error terms are not used in determining the coefficients of the variables. As such, the coefficients of the two-stage regression results are very similar to the original, however in all cases the autocorrelation was corrected with new Durbin-Watson statistics over 1. 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 723,417 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 25,775 Dth is added to the DD estimate for the Residential, Small and Large Commercial classes to determine the total Minnesota State DD Projection of 749,192 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 2020-2021 heating season compared to the 2019-2020 heating season as filed in Docket No. G002/M-19-498. **Attachment 1, Schedule 2** details the demand cost component changes for the 2020-

2021 heating season. The projected DD for the Company increased by 9,501 Dth/day (5,496 Dth/day for Minnesota) for the 2020-2021 heating season. The demand entitlement changes discussed below represent a combination of renewals of existing contract entitlements, new and incremental contracts to serve the slight growth in projected DD, and changes to reservation rates on interstate pipelines. **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 a decrease of demand related total costs of approximately $6,065,529 ($5,287,928 for Minnesota), including contract demand and supplier entitlement changes. This decrease is due primarily to recently concluded agreements settling federal rate cases with both Northern Natural Gas, and Viking Gas Transmission.

a. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2020)

NSP renewed one Viking firm capacity entitlement this year. The previous capacity of 1,500 Dth/day expired October 31, 2020 and has been renewed at the same terms for a one-year term. NSP acquired this capacity to meet firm system requirements, which continues to be necessary this year to meet our DD requirements. The short term of the capacity provides NSP with flexibility in future capacity commitments.
For the past several years, NSP has also purchased short-term capacity on Viking or delivered supply to address a small portion of our overall DD projections. Favorable market conditions on Viking, driven largely by a favorable spot market price differential between Emerson and Chicago City Gates, remain and have resulted in high demand on Viking. For the 2020-2021 season, NSP plans to acquire a total of 13,761 Dth/day of delivered supply from a producer/marketer on Viking capacity for December through February, to meet seasonal peaking needs. NSP has already secured 5,000 Dth/day of this requirement and will look to complete the remaining acquisition before the winter season. The demand costs for this transaction are currently estimated at the Viking maximum tariff rate and included in the supply reservation fees section.

b. Change in Great Lakes Gas Transmission (Great Lakes) entitlement (effective April 1, 2021)

NSP extended two Great Lakes firm transportation agreements for additional two-year terms effective April 1, 2021 at the same terms as the original agreements. These agreements provide access to gas stored in ANR Storage (ANRS) facilities in Michigan, to allow us to meet our Carlton obligations on Northern, and provide regional diversity in our winter gas supplies. This provides additional reliability in meeting our design day supply needs.

c. Change in ANR Storage Co. (ANRS) entitlement (effective April 1, 2021)

NSP has extended our service agreement with ANRS for an additional two-year term, effective April 1, 2021. In September 2019, ANRS was granted Market Based Rate Authority by FERC, beginning January 1, 2020. As a result, ANRS no longer has a tariff rate for service. This extension is at a slightly higher market rate. However, NSP retains the previously approved maximum tariff rates through March 2021, and the new rates continue to be the lowest cost option for NSP's service requirements in the region. The contracted rate is approximately half the cost of the nearest competitor. This agreement allows for the storage of gas supplies in Michigan and provides cost effective method to meet our obligation to supply gas at the Carlton interconnect with Northern. In addition, the capacity provides regional supply diversity, and increased reliability of gas supplies during extreme cold events.

d. Change in Northern Natural Gas (Northern) entitlement (effective November 1, 2021)

As part of Northern's Northern Lights 2021 expansion project, NSP has contracted to acquire an additional 9,459 Dth/day to be effective November 1, 2021 to meet growing demand. Of this quantity, 3,600 Dth/day on a year-round basis, is significantly discounted as part of NSP's existing discount agreement with Northern, and provides for growth in the St. Cloud area. The remaining 5,859 Dth/day is at Northern's maximum tariff rate and will serve new growth areas on NSP's system and will provide NSP with capacity to meet future design day requirements. The discounted capacity will be provided through the remaining term of NSP's discount agreements. The tariff rate portion will be for a term of 10 years from November 1, 2021. Annual costs are expected to be $1.14 million per year and will be included in next year's filing.

3. *Change in Interstate Pipeline Tariff Rates*

a. Change in Viking Tariff Rates (effective January 1, 2020)

On June 28, 2019, Viking filed with the FERC a general Section 4 rate case (RP19-1340) to change rates effective August 1, 2019, in accordance with its previous rate case settlement. Viking proposed an average seven percent rate increase to the rates for NSP. On July 10, NSP filed a protest requesting the proposed rates be suspended for the maximum five-months, implemented thereafter subject to refund, and set for hearing. Following several settlement conferences between Viking, NSP, other customers, and FERC Staff, a Settlement was reached which reduces the maximum tariff rate below the previously effective tariff rate by approximately 12 percent. Viking filed to implement the settlement rates on February 14, 2020, subject to refund pending the approval of the Settlement Agreement. The formal settlement agreement was filed with FERC on February 28, 2020 and approved on July 1, 2020.

The Settlement rates provide NSP customers annual savings of approximately $1.77 million from Viking's filed rates and are included in the instant filing.

b. Change in Northern Tariff Rates (effective January 1, 2020)

FERC initiated a Section 5 (complaint) rate proceeding against Northern on January 16, 2019 (RP19-59), stating that Northern may be over-recovering its cost of service. In response, on July 1, Northern filed a Section 4 rate case (RP19-1353) proposing a 91% rate increase to the Market Area, including NSP's service territory, effective August 1, 2019. NSP filed a protest of Northern's proposed rates on July 15 arguing that the drastic increase in rates was unjust and unreasonable, as were several proposed tariff provisions. NSP participated in subsequent technical and settlement conferences. FERC issued an order on several tariff issues as a result of the technical conference on December 31, 2019.

On December 18, Northern filed to implement interim rates, which were slightly lower (approximately 15 percent) than the filed 91 percent base rate case increase. On February 14, 2020, NSP as a member of a group of large utilities (the BMX group) filed answering testimony in the case. The testimony argued for significantly lower rates than those proposed by Northern, as well as several related tariff issues dealing with pricing and operational services. On May 1, Northern filed its rebuttal testimony. On May 18, Northern, NSP, other customers, and FERC Staff reached a settlement in principle, which results in an increase in market area rates of 28 percent from the pre-January 1 rates. The settlement rates reflect a 63 percent reduction from Northern's proposed rates and save NSP's customers approximately $9.2 million per year over Northern's originally filed rates as a result. The Settlement Agreement was filed with FERC on June 19, and an order addressing the settlement is expected in the fall of 2020.

On May 20 Northern filed to implement the Settlement Rates subject to refund, pending approval of the Settlement. The Settlement Rates are included in the instant filing.

4. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 87.57 percent to 87.18 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 $88,166. **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 slightly decrease our capacity reserve margin from 6.6 percent in November 2019 to 5.7 percent in November 2020, as noted in **Attachment 2, Schedule 1, Page 3**. 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.

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 2020-2021 heating season DD reserve margin for Minnesota State is 42,439 Dth/day or 5.7 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.**

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

Avg Monthly DD Method

2020-2021 Heating Season

Service Region (1)	Projected Jan 2021 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	331,905	68	11,772	0.0339408	91	1.1671632	0.0123	511,809	523,582	
BRAINERD	18,893	3	361	0.0246554	91	0.9708560	0.0123	23,951	24,312	
MAINLINE	15,602	12	2,870	0.0367797	88	1.2018744	0.0123	23,735	26,604	
MAINLINE-WELCOME	2,563	0	0	0.0180387	88	0.7560670	0.0123	2,873	2,873	
WILLMAR	12,224	2	376	0.0251285	88	0.9623432	0.0123	15,404	15,780	
PAYNESVILLE	35,748	23	4,412	0.0471642	94	1.0399022	0.0123	72,206	76,619	
VGT-CHISAGO	2,251	0	0	0.0143776	91	0.7216475	0.0123	2,439	2,439	
WATKINS	8,422	1	409	0.0188286	94	1.0245670	0.0123	10,314	10,723	
TOMAH	16,121	9	1,696	0.0352610	88	0.5619028	0.0123	23,960	25,656	
RED WING	8,072	4	1,096	0.0360355	88	1.1232051	0.0123	12,545	13,642	
GRAND FORKS MN	3,159	1	63	0.0391512	98	0.1292068	0.0123	4,748	4,812	
FARGO MN	14,260	7	2,719	0.0338803	98	0.4065567	0.0123	19,432	22,151	
MN State	**469,220**	**130**	**25,775**					**723,417**	**749,192**	**87.18%**
GRAND FORKS ND	17,224	0	0	0.0170051	98	1.6559091	0.0123	31,297	31,297	
FARGO ND	41,364	0	0	0.0170552	98	1.7494427	0.0123	75,509	75,509	
WBI ND	1,427	0	0	0.0181820	98	1.3967217	0.0123	2,753	2,753	
ND State	60,014	0	0					109,559	109,559	12.82%
TOTAL	**529,234**	**130**	**25,775**					**832,976**	**858,750**	**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 60 months January 2015 to December 2019.
(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.

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2020-2021 Heating Season

Division/Region (1)	Projected Firm Jan 2021 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) 2021 Unacc. Volume	Load Variation	Day Base	Total	2020 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO																
Total Residential	308,997	0.0107028	91	1.1485474	0.9858	64.0655	0.0000	0.0123	3,834	300,948	11,674	**316,456**	313,234	3,222	13,622	**330,079**
Total Small Commercial	15,425	0.0309258	91	1.6245713	0.9065	27.0011	0.0000	0.0123	542	43,410	824	**44,777**	43,834	942	1,927	**46,704**
Total Large Commercial	7,483	0.1780530	91	26.9666889	0.9804	54.3645	0.0000	0.0123	1,568	121,248	6,638	**129,454**	126,253	3,201	5,573	**135,026**
Industrial	68	Contract Demand	-	-				-	-	-	-	**11,772**	11,499	273	-	**11,772**
	331,973	0.0339408		1.167163196					5,945	465,606	19,137	**502,459**	494,820	7,639	21,123	**523,582**
														1.5%		
BRAINERD																
Total Residential	17,414	0.0101898	91	0.8615056	0.9807	54.7411	0.0000	0.0123	204	16,147	493	**16,845**	16,682	163	725	**17,570**
Total Small Commercial	1,217	0.0210158	91	2.4882772	0.8430	21.9219	0.0000	0.0123	30	2,328	100	**2,457**	2,309	148	106	**2,563**
Total Large Commercial	263	0.1322364	91	52.6070608	0.9541	35.0494	0.0000	0.0123	44	3,162	455	**3,661**	3,458	203	158	**3,818**
Industrial	3	Contract Demand	-	-				-	-	-	-	**361**	361	0	-	**361**
	18,896	0.0246554		0.970856033					278	21,637	1,048	**23,324**	22,810	514	988	**24,312**
														2.3%		
MAINLINE																
Total Residential	14,055	0.0102830	88	1.1691973	0.9763	49.3457	0.0000	0.0123	163	12,719	541	**13,422**	13,453	(31)	578	**14,000**
Total Small Commercial	1,148	0.0267712	88	1.6497454	0.8154	20.5742	0.0000	0.0123	34	2,705	62	**2,801**	2,724	78	121	**2,922**
Total Large Commercial	399	0.1689127	88	39.9668238	0.9246	21.1419	0.0000	0.0123	79	5,929	524	**6,532**	6,654	(122)	281	**6,813**
Industrial	12	Contract Demand	-	-				-	-	-	-	**2,870**	3,275	(405)	-	**2,870**
	15,614	0.0367797		1.201874441					276	21,352	1,127	**25,625**	26,106	(481)	980	**26,604**
														-1.8%		
MAINLINE-WELCOME																
Total Residential	2,406	0.0100968	88	0.6805583	0.9759	48.8554	0.0000	0.0123	27	2,138	54	**2,218**	2,208	10	95	**2,314**
Total Small Commercial	138	0.0159525	88	1.1333409	0.9053	23.7727	0.0000	0.0123	2	194	5	**201**	203	(2)	9	**210**
Total Large Commercial	20	0.1451892	88	124.8700946	0.2186	4.1839	0.0001	0.0123	4	250	81	**335**	341	(6)	14	**349**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,563	0.0180387		0.756067023					33	2,582	140	**2,755**	2,752	2	119	**2,873**
														0.1%		
WILLMAR																
Total Residential	11,328	0.0101076	88	0.9200266	0.8880	21.6510	0.0000	0.0123	128	10,076	343	**10,547**	9,459	1,088	454	**11,001**
Total Small Commercial	721	0.0246795	88	1.5871075	0.8741	20.2683	0.0000	0.0123	20	1,565	38	**1,623**	1,630	(7)	70	**1,692**
Total Large Commercial	175	0.1578286	88	24.3998769	0.9042	23.6164	0.0000	0.0123	31	2,427	140	**2,599**	2,409	190	112	**2,711**
Industrial	2	Contract Demand	-	-				-	-	-	-	**376**	527	(151)	-	**376**
	12,226	0.0251285		0.962343151					179	14,069	521	**15,144**	14,024	1,120	636	**15,780**
														8.0%		
PAYNESVILLE																
Total Residential	31,714	0.0103799	94	1.0633942	0.8176	15.3969	0.0000	0.0123	393	30,944	1,109	**32,446**	32,899	(453)	1,397	**33,843**
Total Small Commercial	2,850	0.0612729	94	0.7926245	0.3203	6.6312	0.0000	0.0123	202	16,417	74	**16,694**	15,690	1,004	719	**17,412**
Total Large Commercial	1,183	0.1676071	94	30.9236761	0.6694	10.0382	0.0000	0.0123	243	18,640	1,203	**20,086**	19,964	122	865	**20,951**
Industrial	23	Contract Demand	-	-				-	-	-	-	**4,412**	4,173	239	-	**4,412**
	35,771	0.0471642		1.039902182					839	66,000	2,387	**73,639**	72,726	913	2,980	**76,619**
														1.3%		
VGT-CHISAGO																
Total Residential	2,143	0.0100379	91	0.7067655	0.9650	40.3514	0.0000	0.0123	25	1,958	50	**2,032**	2,027	5	87	**2,119**
Total Small Commercial	99	0.0204769	91	0.9955182	0.9417	30.8777	0.0000	0.0123	2	185	3	**190**	196	(6)	8	**198**
Total Large Commercial	9	0.1439391	91	2.3427800	0.9282	21.6273	0.0000	0.0123	1	114	1	**116**	102	14	5	**121**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,251	0.0143776		0.721647542					28	2,256	54	**2,338**	2,325	13	101	**2,439**
														0.6%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2020-2021 Heating Season

WATKINS																
Total Residential	8,123	0.0098395	94	0.9878605	0.9483	32.9151	0.0000	0.0123	95	7,513	264	**7,873**	7,793	79	339	**8,212**
Total Small Commercial	227	0.0288946	94	2.1904303	0.8149	16.1475	0.0000	0.0123	8	617	16	**641**	681	(40)	28	**669**
Total Large Commercial	72	0.1881740	94	36.1952936	0.9197	25.6165	0.0000	0.0123	17	1,272	86	**1,374**	1,402	(27)	59	**1,434**
Industrial	1	Contract Demand	-	-				-	-	-	-	**409**	409	0	-	**409**
	8,423	0.0188286		1.024566953					120	9,402	366	**10,297**	10,285	12	426	**10,723**
														0.1%		
TOMAH																
Total Residential	14,448	0.0101033	88	0.4054627	0.9794	52.9617	0.0000	0.0123	160	12,846	193	**13,199**	13,219	(20)	568	**13,767**
Total Small Commercial	1,283	0.0257114	88	2.1786221	0.9505	33.6733	0.0000	0.0123	37	2,902	92	**3,030**	3,046	(16)	130	**3,161**
Total Large Commercial	390	0.1863384	88	21.2065684	0.9669	41.5512	0.0000	0.0123	82	6,389	272	**6,742**	6,697	45	290	**7,032**
Industrial	9	Contract Demand	-	-				-	-	-	-	**1,696**	1,686	10	-	**1,696**
	16,130	0.0352610		0.561902807					278	22,136	556	**24,668**	24,648	20	989	**25,656**
														0.1%		
RED WING																
Total Residential	7,285	0.0102082	88	0.9076567	0.9175	25.6356	0.0000	0.0123	83	6,544	218	**6,845**	6,856	(11)	295	**7,139**
Total Small Commercial	587	0.0283152	88	3.8037873	0.7243	12.4908	0.0000	0.0123	19	1,463	73	**1,555**	1,633	(77)	67	**1,622**
Total Large Commercial	200	0.1942139	88	25.5985286	0.8311	17.0669	0.0000	0.0123	44	3,415	168	**3,628**	3,483	145	156	**3,784**
Industrial	4	Contract Demand	-	-				-	-	-	-	**1,096**	1,277	(181)	-	**1,096**
	8,076	0.0360355		1.123205116					146	11,423	459	**13,124**	13,248	(124)	518	**13,642**
														-0.9%		
GRAND FORKS MN																
Total Residential	2,806	0.0096728	98	0.0897791	0.9733	46.3781	0.0000	0.0123	33	2,660	8	**2,701**	2,713	(12)	116	**2,817**
Total Small Commercial	262	0.0216946	98	0.1916430	0.8092	15.7140	0.0000	0.0123	7	557	2	**566**	660	(94)	24	**590**
Total Large Commercial	91	0.1376824	98	15.3749813	0.9775	50.6715	0.0000	0.0123	16	1,224	46	**1,286**	1,233	53	55	**1,341**
Industrial	1	Contract Demand	-	-				-	-	-	-	**63**	156	(93)	-	**63**
	3,160	0.0391512		0.129206761					55	4,441	56	**4,616**	4,762	(146)	196	**4,812**
														-3.1%		
FARGO MN																
Total Residential	12,822	0.0081335	98	0.3528477	0.9730	45.7478	0.0000	0.0123	127	10,220	149	**10,496**	10,512	(16)	452	**10,948**
Total Small Commercial	1,086	0.0238449	98	0.8258907	0.8646	22.4579	0.0000	0.0123	31	2,537	29	**2,598**	2,665	(67)	112	**2,710**
Total Large Commercial	353	0.1491268	98	26.6586393	0.9746	47.5877	0.0000	0.0123	67	5,160	310	**5,536**	5,472	64	238	**5,775**
Industrial	7	Contract Demand	-	-				-	-	-	-	**2,719**	2,693	26	-	**2,719**
	14,267	0.0338803		0.40655667					226	17,917	488	**21,349**	21,342	7	802	**22,151**
														0.0%		
MN STATE																
Total Residential	**433,541**											**435,079**	**431,055**	**4,023**	**18,729**	**453,807**
Total Small Commercial	**25,043**											**77,133**	**75,271**	**1,862**	**3,320**	**80,453**
Total Large Commercial	**10,636**											**181,349**	**177,467**	**3,883**	**7,807**	**189,156**
Contract Demand	**130**											**25,775**	**26,056**	**-281**	**0**	**25,775**
	469,350											**719,336**	**709,849**	**9,487**	**29,856**	**749,192**
														1.3%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2020-2021 Heating Season

Division/Region (1)	Projected Firm Jan 2021 Cust (2)	Load Variation (Dth/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Dth) (5) Intercept	R-Square			Lost & Unacc. Factor (6)	Design Day (Dth) 2021 Unacc. Volume	Load Variation	Day Base	Total	2020 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND																
Total Residential	14,970	0.0093014	98	0.2932676	0.9776	50.7867	0.0000	0.0123	169	13,646	144	**13,959**	13,634	325	601	**14,560**
Total Small Commercial	2,254	0.0681749	98	10.7068935	0.9693	43.1378	0.0000	0.0123	194	15,058	794	**16,046**	15,360	686	691	**16,737**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	17,224	0.0170051		1.655909139					364	28,703	938	**30,005**	28,994	1,011	1,292	**31,297**
														3.5%		
FARGO ND																
Total Residential	34,817	0.0089048	98	0.2636958	0.9799	53.6802	0.0000	0.0123	376	30,384	302	**31,062**	29,841	1,221	1,337	**32,399**
Total Small Commercial	6,547	0.0603991	98	9.6507226	0.9723	45.4953	0.0000	0.0123	501	38,752	2,078	**41,331**	39,471	1,859	1,779	**43,110**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	41,364	0.0170552		1.74944266					877	69,135	2,380	**72,393**	69,313	3,080	3,116	**75,509**
														4.4%		
WBI ND																
Total Residential	1,235	0.0098633	98	0.3671292	0.9410	30.4180	0.0000	0.0123	15	1,194	15	**1,224**	1,158	66	53	**1,276**
Total Small Commercial	191	0.0718850	98	8.0434385	0.6613	10.7794	0.0000	0.0123	17	1,348	51	**1,416**	1,110	305	61	**1,477**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	1,427	0.0181820		1.396721747					32	2,542	66	**2,640**	2,268	371	114	**2,753**
														16.4%		
ND STATE																
Total Residential	**51,022**											**46,245**	**44,633**	**1,612**	**1,991**	**48,236**
Total Small Commercial	**8,992**											**58,792**	**55,941**	**2,851**	**2,531**	**61,323**
Total Large Commercial	**0**											**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**											**-**	**-**	**-**	**-**	**-**
	60,014											**105,037**	**100,574**	**4,463**	**4,522**	**109,559**
														4.4%		
Grand Total																
Total Residential	**484,563**											**481,324**	**475,689**	**5,635**	**20,719**	**502,043**
Total Small Commercial	**34,035**											**135,925**	**131,212**	**4,713**	**5,851**	**141,777**
Total Large Commercial	**10,636**											**181,349**	**177,467**	**3,883**	**7,807**	**189,156**
Contract Demand	**130**											**25,775**	**26,056**	**(281)**	**-**	**25,775**
	529,364											**824,374**	**810,423**	**13,950**	**34,377**	**858,751**
														1.7%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2020-2021 Heating Season

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2021 FORECAST	2020 FORECAST	Difference	%Diff
METRO	331,905	328,997	2,908	0.9%
BRAINERD	18,893	18,728	165	0.9%
MAINLINE	15,602	15,639	(36)	-0.2%
MAINLINE-WELCOME	2,563	2,551	13	0.5%
WILLMAR	12,224	10,996	1,227	11.2%
PAYNESVILLE	35,748	36,242	(495)	-1.4%
VGT-CHISAGO	2,251	2,241	10	0.4%
WATKINS	8,422	8,342	80	1.0%
TOMAH	16,121	16,157	(37)	-0.2%
RED WING	8,072	8,078	(6)	-0.1%
GRAND FORKS MN	3,159	3,162	(4)	-0.1%
FARGO MN	14,260	14,113	147	1.0%
MN STATE	469,220	465,247	3,973	0.9%
GRAND FORKS ND	17,224	16,763	461	2.7%
FARGO ND	41,364	39,665	1,699	4.3%
WBI ND	1,427	1,343	84	6.2%
ND STATE	60,014	57,771	2,243	3.9%
TOTAL NSP MN	529,234	523,018	6,216	**1.2%**

2021 Customer Counts

	MN	ND	
Res	433,541	51,022	**484,563**
Sm Com	25,043	8,992	**34,035**
Lg Com	10,636	0	**10,636**
Ind	130	0	**130**
	469,350	60,014	**529,364**

2021 Design Day Use By Customer Class

	MN	ND	
Res	456,106	48,483	**504,588**
Sm Com	75,799	61,637	**137,436**
Lg Com	190,952	0	**190,952**
Ind	25,775	0	**25,775**
	748,632	110,120	**858,751**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2021 FORECAST	2020 FORECAST	Difference	%Diff
METRO	523,582	518,744	4,838	0.9%
BRAINERD	24,312	23,921	391	1.6%
MAINLINE	26,604	27,236	(632)	-2.3%
MAINLINE-WELCOME	2,873	2,889	(15)	-0.5%
WILLMAR	15,780	14,692	1,087	7.4%
PAYNESVILLE	76,619	76,119	499	0.7%
VGT-CHISAGO	2,439	2,440	(2)	-0.1%
WATKINS	10,723	10,774	(51)	-0.5%
TOMAH	25,656	25,784	(128)	-0.5%
RED WING	13,642	13,841	(199)	-1.4%
GRAND FORKS MN	4,812	4,990	(178)	-3.6%
FARGO MN	22,151	22,265	(114)	-0.5%
MN STATE	749,192	743,696	5,496	0.7%
GRAND FORKS ND	31,297	30,429	868	2.9%
FARGO ND	75,509	72,743	2,766	3.8%
WBI ND	2,753	2,381	373	15.7%
ND STATE	109,559	105,553	4,006	3.8%
TOTAL NSP MN	858,750	849,249	9,501	1.1%

MN / ND Allocation Factors

2021 DD	2020 DD	
0.8718	0.8757	**MN State Allocation**
0.1282	0.1243	**ND State Allocation**

NNG SYSTEM	2021 FORECAST	2020 FORECAST	Difference	%Diff
METRO	523,582	518,744	4,838	0.9%
BRAINERD	24,312	23,921	391	1.6%
MAINLINE	26,604	27,236	(632)	-2.3%
MAINLINE-WELCOME	2,873	2,889	(15)	-0.5%
WILLMAR	15,780	14,692	1,087	7.4%
PAYNESVILLE	76,619	76,119	499	0.7%
WATKINS	10,723	10,774	(51)	-0.5%
TOMAH	25,656	25,784	(128)	-0.5%
RED WING	13,642	13,841	(199)	-1.4%
NNG SUBTOTAL	719,791	714,000	5,791	0.8%

VGT SYSTEM				
VGT-CHISAGO	2,439	2,440	(2)	-0.1%
GRAND FORKS MN	4,812	4,990	(178)	-3.6%
FARGO MN	22,151	22,265	(114)	-0.5%
GRAND FORKS ND	31,297	30,429	868	2.9%
FARGO ND	75,509	72,743	2,766	3.8%
WBI ND	2,753	2,381	373	15.7%
VGT SUBTOTAL	138,960	135,248	3,712	2.7%
VGT & NNG TOTAL	858,751	849,248	9,503	1.1%

Northern States Power Company
DEMAND COST OF GAS IMPACT - NOVEMBER 2020

Docket No. G002/M-20-___
Attachment 1
Schedule 2

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FSS (Jan - Dec)[1]	(12)	$ 1.7820	12	$ (256.61)
ANR FTS-1 (Apr - Oct)[2]	(4)	$ 5.7290	7	$ (160.41)
VGT FT-A (Nov - Dec)[3]	(20,200)	$ 4.3706	2	$ (176,572.24)
VGT FT-A (Jan - Oct)[3]	(20,200)	$ 4.6653	10	$ (942,390.60)
VGT FT-A (Jan - Dec)[3]	20,200	$ 3.8060	12	$ 922,574.40
VGT FT-A (Nov - Dec)[3]	(29,002)	$ 4.3706	2	$ (253,512.28)
VGT FT-A (Jan - Oct)[3]	(29,002)	$ 4.6653	10	$ (1,353,030.31)
VGT FT-A (Jan - Dec)[3]	29,002	$ 3.8060	12	$ 1,324,579.34
VGT FT-A (Nov - Dec)[3]	(4,239)	$ 4.3706	2	$ (37,053.95)
VGT FT-A (Jan - Mar)[3]	(4,239)	$ 4.6653	3	$ (59,328.62)
VGT FT-A (Nov - Mar)[3]	4,239	$ 3.8060	5	$ 80,668.17
VGT FT-A (Nov - Dec)[3]	(10,000)	$ 4.3706	2	$ (87,412.00)
VGT FT-A (Jan - Oct)[3]	(10,000)	$ 4.6653	10	$ (466,530.00)
VGT FT-A (Jan - Dec)[3]	10,000	$ 3.8060	12	$ 456,720.00
VGT FT-A (Nov - Dec)[3]	(15,600)	$ 5.3593	2	$ (167,210.16)
VGT FT-A (Jan - Oct)[3]	(15,600)	$ 5.6540	10	$ (882,024.00)
VGT FT-A (Jan - Dec)[3]	15,600	$ 4.7580	12	$ 890,697.60
VGT FT-A (Nov - Dec)[3]	(1,903)	$ 4.3706	2	$ (16,634.50)
VGT FT-A (Jan - Oct)[3]	(1,903)	$ 4.6653	10	$ (88,780.66)
VGT FT-A (Jan - Dec)[3]	1,903	$ 3.8060	12	$ 86,913.82
VGT FT-A (Nov - Dec)[3]	(72,213)	$ 5.3593	2	$ (774,022.26)
VGT FT-A (Jan - Oct)[3]	(72,213)	$ 5.6540	10	$ (4,082,923.02)
VGT FT-A (Jan - Dec)[3]	72,213	$ 4.7580	12	$ 4,123,073.45
VGT FT-A (Nov - Dec)[3]	(15,000)	$ 5.3593	2	$ (160,779.00)
VGT FT-A (Jan - Oct)[3]	(15,000)	$ 5.6540	10	$ (848,100.00)
VGT FT-A (Jan - Dec)[3]	15,000	$ 4.7580	12	$ 856,440.00
VGT FT-A (Nov - Dec)[3]	(1,500)	$ 4.7507	2	$ (14,252.10)
VGT FT-A (Jan - Oct)[3]	(1,500)	$ 4.8293	10	$ (72,439.50)
VGT FT-A (Jan - Dec)[3]	1,500	$ 3.9106	12	$ 70,390.80
NNG TF12-Base (Nov-Dec)[4]	(104,117)	$ 10.2300	2	$ (2,130,233.82)
NNG TF12-Base (Jan-Mar)[4]	(104,117)	$ 10.3207	3	$ (3,223,680.97)
NNG TF12-Base (Nov-Mar)[4]	104,117	$ 13.1450	5	$ 6,843,089.83
NNG TF12-Base (Apr-Oct)[4]	(104,117)	$ 10.3207	7	$ (7,521,922.25)
NNG TF12-Base (Apr-Oct)[4]	104,117	$ 7.3030	7	$ 5,322,565.16
NNG TF3 (Nov-Dec)[4]	(62,415)	$ 15.1530	2	$ (1,891,548.99)
NNG TF3 (Jan-Mar)[4]	(62,415)	$ 24.2448	3	$ (4,539,717.58)
NNG TF3 (Nov-Mar)[4]	62,415	$ 19.4710	5	$ 6,076,412.33
NNG TFX (Nov-Dec)[5]	(28,500)	$ 15.1530	2	$ (863,721.00)
NNG TFX (Jan-Mar)[5]	(28,500)	$ 28.8810	3	$ (2,469,325.50)
NNG TFX (Nov-Mar)[5]	28,500	$ 19.4710	5	$ 2,774,617.50
NNG TFX (Nov-Dec)[5]	(57,491)	$ 15.1530	2	$ (1,742,322.25)
NNG TFX (Jan-Mar)[5]	(20,861)	$ 28.8810	3	$ (1,807,459.62)
NNG TFX (Jan-Mar)[5]	(36,630)	$ 22.1055	3	$ (2,429,173.40)
NNG TFX (Nov-Mar)[5]	57,491	$ 19.4710	5	$ 5,597,036.31
NNG TFX (Apr-Jun/Sept-Oct)[5]	16,436	$ 7.3030	2	$ 240,064.22
NNG TFX (Apr-Jun/Sept-Oct)[5]	(15,436)	$ 10.8300	2	$ (334,343.76)
NNG TFX (Apr-Jun/Sept-Oct)[5]	(1,000)	$ 10.0000	2	$ (20,000.00)
NNG TFX (Apr-Jun/Sept-Oct)[5]	35,739	$ 7.3030	5	$ 1,305,009.59
NNG TFX (Apr-Jun/Sept-Oct)[5]	(15,436)	$ 10.8300	5	$ (835,859.40)
NNG TFX (Apr-Jun/Sept-Oct)[5]	(20,303)	$ 10.0000	5	$ (1,015,150.00)
NNG TFX (Nov-Dec)[5]	(8,875)	$ 15.1530	2	$ (268,965.75)
NNG TFX (Jan-Mar)[5]	(8,875)	$ 28.8810	3	$ (768,956.63)
NNG TFX (Nov-Mar)[5]	8,875	$ 19.4710	5	$ 864,025.63
NNG TFX (Apr-Oct)[5]	(8,875)	$ 10.8300	7	$ (672,813.75)
NNG TFX (Apr-Oct)[5]	8,875	$ 7.3030	7	$ 453,698.88
NNG FDD (Jan-Dec)[6]	(140,230)	$ 1.7140	2	$ (480,708.44)
NNG FDD (Jan-Dec)[6]	(140,230)	$ 3.7443	10	$ (5,250,631.89)
NNG FDD (Jan-Dec)[6]	140,230	$ 2.8624	12	$ 4,816,732.22
NNG FDD (Jan-Dec)[6]	(78,050)	$ 1.7140	2	$ (267,555.40)
NNG FDD (Jan-Dec)[6]	(78,050)	$ 3.7443	10	$ (2,922,426.15)
NNG FDD (Jan-Dec)[6]	78,050	$ 2.8624	12	$ 2,680,923.84
Total				$ (6,153,695.70)

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

PROTECTED DATA ENDS]

Total	2,671	$88,166.44
Total MN & ND Demand Cost Adjustment		**($6,065,529.26)**
Minnesota Allocation Factor (MN/ND Allocated Demand)		87.18%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ (5,287,928.41)**

[1] ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v.1.1.0, Effective August 1, 2016
[2] ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 2.0.0, Effective April 1, 2017
[3] VGT Volume No. 1, Part 5.0 Statement of Rates, (RP19-1340) Effective January 1, 2020
[4] NNG Sixth Revised Volume No. 1, Fifteenth Revised Sheet No. 50 (RP19-1353), Effective January 1, 2020
[5] NNG Sixth Revised Volume No. 1, Eighteenth Revised Sheet No. 51 (RP19-1353), Effective January 1, 2020
[6] NNG Sixth Revised Volume No. 1, Second Revised Sheet No. 55 (RP19-1353), Effective January 1, 2020

Northern States Power Company
Demand Cost Changes from Prior Year

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2019 SUPPLEMENTAL FILED COSTS				**$39,215,828.06**	**$33,504,460.03**	**$72,720,288.09**				
2019 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2019 ACTUAL COSTS				**$ 39,215,828.06**	**$ 33,504,460.03**	**$ 72,720,288.09**				
CHANGES FOR 2020 FILING										
Contract Demand Entitlement Changes										
ANR FSS (Jan - Dec)	(12)	$ 1.7820	12		$ (256.61)	$ (256.61)			$ (256.61)	1
ANR FTS-1 (Apr - Oct)	(4)	$ 5.7290	7		$ (160.41)	$ (160.41)			$ (160.41)	1
VGT FT-A (Jan - Dec)	(20,200)	$ 4.3706	2	$ (176,572.24)		$ (176,572.24)		$ (176,572.24)		2
VGT FT-A (Jan - Dec)	(20,200)	$ 4.6653	10	$ (942,390.60)		$ (942,390.60)		$ (942,390.60)		2
VGT FT-A (Jan - Dec)	20,200	$ 3.8060	12	$ 922,574.40		$ 922,574.40		$ 922,574.40		2
VGT FT-A (Jan - Dec)	(29,002)	$ 4.3706	2	$ (253,512.28)		$ (253,512.28)	$ (253,512.28)			2
VGT FT-A (Jan - Dec)	(29,002)	$ 4.6653	10	$ (1,353,030.31)		$ (1,353,030.31)	$ (1,353,030.31)			2
VGT FT-A (Jan - Dec)	29,002	$ 3.8060	12	$ 1,324,579.34		$ 1,324,579.34	$ 1,324,579.34			2
VGT FT-A (Nov-Mar)	(4,239)	$ 4.3706	2		$ (37,053.95)	$ (37,053.95)	$ (37,053.95)			2
VGT FT-A (Nov-Mar)	(4,239)	$ 4.6653	3		$ (59,328.62)	$ (59,328.62)	$ (59,328.62)			2
VGT FT-A (Nov-Mar)	4,239	$ 3.8060	5		$ 80,668.17	$ 80,668.17	$ 80,668.17			2
VGT FT-A (Jan - Dec)	(10,000)	$ 4.3706	2	$ (87,412.00)		$ (87,412.00)	$ (87,412.00)			2
VGT FT-A (Jan - Dec)	(10,000)	$ 4.6653	10	$ (466,530.00)		$ (466,530.00)	$ (466,530.00)			2
VGT FT-A (Jan - Dec)	10,000	$ 3.8060	12	$ 456,720.00		$ 456,720.00	$ 456,720.00			2
VGT FT-A (Jan - Dec)	(15,600)	$ 5.3593	2	$ (167,210.16)		$ (167,210.16)	$ (167,210.16)			2
VGT FT-A (Jan - Dec)	(15,600)	$ 5.6540	10	$ (882,024.00)		$ (882,024.00)	$ (882,024.00)			2
VGT FT-A (Jan - Dec)	15,600	$ 4.7580	12	$ 890,697.60		$ 890,697.60	$ 890,697.60			2
VGT FT-A (Jan - Dec)	(1,903)	$ 4.3706	2	$ (16,634.50)		$ (16,634.50)	$ (16,634.50)			2
VGT FT-A (Jan - Dec)	(1,903)	$ 4.6653	10	$ (88,780.66)		$ (88,780.66)	$ (88,780.66)			2
VGT FT-A (Jan - Dec)	1,903	$ 3.8060	12	$ 86,913.82		$ 86,913.82	$ 86,913.82			2
VGT FT-A (Jan - Dec)	(72,213)	$ 5.3593	2	$ (774,022.26)		$ (774,022.26)		$ (774,022.26)		2
VGT FT-A (Jan - Dec)	(72,213)	$ 5.6540	10	$ (4,082,923.02)		$ (4,082,923.02)		$ (4,082,923.02)		2
VGT FT-A (Jan - Dec)	72,213	$ 4.7580	12	$ 4,123,073.45		$ 4,123,073.45		$ 4,123,073.45		2
VGT FT-A (Jan - Dec)	(15,000)	$ 5.3593	2	$ (160,779.00)		$ (160,779.00)	$ (160,779.00)			2
VGT FT-A (Jan - Dec)	(15,000)	$ 5.6540	10	$ (848,100.00)		$ (848,100.00)	$ (848,100.00)			2
VGT FT-A (Jan - Dec)	15,000	$ 4.7580	12	$ 856,440.00		$ 856,440.00	$ 856,440.00			2
VGT FT-A (Jan - Dec)	(1,500)	$ 4.7507	2	$ (14,252.10)		$ (14,252.10)		$ (14,252.10)		2
VGT FT-A (Jan - Dec)	(1,500)	$ 4.8293	10	$ (72,439.50)		$ (72,439.50)		$ (72,439.50)		2
VGT FT-A (Jan - Dec)	1,500	$ 3.9106	12	$ 70,390.80		$ 70,390.80		$ 70,390.80		2
NNG TF12-Base (Nov-Mar)	(104,117)	$10.2300	2	$ (2,130,233.82)		$ (2,130,233.82)	$ (2,130,233.82)			3
NNG TF12-Base (Nov-Mar)	(104,117)	$10.3207	3	$ (3,223,680.97)		$ (3,223,680.97)				3
NNG TF12-Base (Nov-Mar)	104,117	$13.1450	5	$ 6,843,089.83		$ 6,843,089.83	$ 6,843,089.83			3
NNG TF12-Base (Apr-Oct)	(104,117)	$10.3207	7	$ (7,521,922.25)		$ (7,521,922.25)	$ (7,521,922.25)			3
NNG TF12-Base (Apr-Oct)	104,117	$ 7.3030	7	$ 5,322,565.16		$ 5,322,565.16	$ 5,322,565.16			3
NNG TF5 (Nov-Mar)	(62,415)	$15.1530	2		$ (1,891,548.99)	$ (1,891,548.99)	$ (1,891,548.99)			3
NNG TF5 (Nov-Mar)	(62,415)	$24.2448	3		$ (4,539,717.58)	$ (4,539,717.58)	$ (4,539,717.58)			3
NNG TF5 (Nov-Mar)	62,415	$19.4710	5		$ 6,076,412.33	$ 6,076,412.33	$ 6,076,412.33			3
NNG TFX (Nov-Mar)	(28,500)	$15.1530	2		$ (863,721.00)	$ (863,721.00)	$ (863,721.00)			3
NNG TFX (Nov-Mar)	(28,500)	$28.8810	3		$ (2,469,325.50)	$ (2,469,325.50)	$ (2,469,325.50)			3
NNG TFX (Nov-Mar)	28,500	$19.4710	5		$ 2,774,617.50	$ 2,774,617.50	$ 2,774,617.50			3
NNG TFX (Nov-Mar)	(57,491)	$15.1530	2		$ (1,742,322.25)	$ (1,742,322.25)	$ (1,742,322.25)			3
NNG TFX (Nov-Mar)	(20,861)	$28.8810	3		$ (1,807,459.62)	$ (1,807,459.62)	$ (1,807,459.62)			3
NNG TFX (Nov-Mar)	(36,630)	$22.1055	3		$ (2,429,173.40)	$ (2,429,173.40)	$ (2,429,173.40)			3
NNG TFX (Nov-Mar)	57,491	$19.4710	5		$ 5,597,036.31	$ 5,597,036.31	$ 5,597,036.31			3
NNG TFX (Jul-Aug)	16,436	$ 7.3030	2	$ 240,064.22		$ 240,064.22	$ 240,064.22			3
NNG TFX (Jul-Aug)	(15,436)	$10.8300	2	$ (334,343.76)		$ (334,343.76)	$ (334,343.76)			3
NNG TFX (Jul-Aug)	(1,000)	$10.0000	2	$ (20,000.00)		$ (20,000.00)	$ (20,000.00)			3
NNG TFX (Apr-Jun/Sept-Oct)	35,739	$ 7.3030	5	$ 1,305,009.59		$ 1,305,009.59	$ 1,305,009.59			3
NNG TFX (Apr-Jun/Sept-Oct)	(15,436)	$10.8300	5	$ (835,859.40)		$ (835,859.40)	$ (835,859.40)			3
NNG TFX (Apr-Jun/Sept-Oct)	(20,303)	$10.0000	5	$ (1,015,150.00)		$ (1,015,150.00)	$ (1,015,150.00)			3
NNG TFX (Nov-Mar)	(8,875)	$15.1530	2		$ (268,965.75)	$ (268,965.75)	$ (268,965.75)			3
NNG TFX (Nov-Mar)	(8,875)	$28.8810	3		$ (768,956.63)	$ (768,956.63)	$ (768,956.63)			3
NNG TFX (Nov-Mar)	8,875	$19.4710	5		$ 864,025.63	$ 864,025.63	$ 864,025.63			3
NNG TFX (Apr-Oct)	(8,875)	$10.8300	7	$ (672,813.75)		$ (672,813.75)	$ (672,813.75)			3
NNG TFX (Apr-Oct)	8,875	$ 7.3030	7	$ 453,698.88		$ 453,698.88	$ 453,698.88			3
NNG FDD (Jan-Dec)	(140,230)	$ 1.7140	2		$ (480,708.44)	$ (480,708.44)			$ (480,708.44)	3
NNG FDD (Jan-Dec)	(140,230)	$ 3.7443	10		$ (5,250,631.89)	$ (5,250,631.89)			$ (5,250,631.89)	3
NNG FDD (Jan-Dec)	140,230	$ 2.8624	12		$ 4,816,732.22	$ 4,816,732.22			$ 4,816,732.22	3
NNG FDD (Jan-Dec)	(78,050)	$ 1.7140	2		$ (267,555.40)	$ (267,555.40)			$ (267,555.40)	3
NNG FDD (Jan-Dec)	(78,050)	$ 3.7443	10		$ (2,922,426.15)	$ (2,922,426.15)			$ (2,922,426.15)	3
NNG FDD (Jan-Dec)	78,050	$ 2.8624	12		$ 2,680,923.84	$ 2,680,923.84			$ 2,680,923.84	3
Total				$ (3,244,799.52)	$ (2,908,896.18)	$ (6,153,695.70)	$ (559,370.82)	$ (946,561.07)	$ (1,424,082.84)	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										4
										4
										5
										6
									PROTECTED DATA ENDS]	
Total				$ -	$ 88,166.44	$ 88,166.44	$ 15,000.00	$ 73,166.44	$ -	
TOTAL OF 2020 CHANGES				**$ (3,244,799.52)**	**$ (2,820,729.75)**	**$ (6,065,529.26)**	**$ (544,370.82)**	**$ (873,394.64)**	**$ (1,424,082.84)**	
2020 COSTS				**$ 35,971,028.54**	**$ 30,683,730.29**	**$ 66,654,758.83**				
2020 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							-38%	-62%		7

Footnote
1. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
2. Rate change due to Settlement of Rate Case (RP19-1340), Rates to be effective January 1, 2020 pending FERC approval.
3. Rate change due to Settlement of Rate Case (RP19-1353), Rates to be effective January 1, 2020 pending FERC approval.
4. Expired peaking supply contract with demand charges in effect November 1, 2019 through March 31, 2020
5. Acquired peaking supply contract with demand charges in effect November 1, 2020 through March 31, 2021
6. Delivered supply in lieu of seasonal Viking capacity purchase.
7. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purposes of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

DESIGN DAY CALCULATION

State of Minnesota	Jan-2021 Budget Customer	2021 MMBtu Design Day[1]	2020 MMBtu Design Day[1]	MMBtu Change
Residential	433,541	453,807	452,392	1,416
Commercial	35,679	269,609	265,247	4,362
Demand Billed	130	25,775	26,056	(281)
State of Minnesota Total	**469,350**	**749,192**	**743,696**	**5,496**
State of North Dakota Total	60,014	109,559	105,553	4,006
Total Xcel Energy - Gas Utility Operations	529,364	858,750	849,248	9,502

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER
UPC DD Method

Minnesota Company	Jan-2021 Budget Customer	Jan-2020 Budget Customer	Change
Residential	484,563	479,125	5,438
Commercial	44,671	43,893	778
TOTAL	529,234	523,018	6,216
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	832,976	823,193	
Demand Billed Customers	130	135	
Contracted Billing Demand of Demand Billed Customers	25,775	26,056	
Projected Design Day (Dth)	858,751	849,249	9,503

[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-2021 Budget	Jan-2020 Budget
Reserve Margin	49,291	56,123
Total Available Capacity	908,042	905,371
Entitlement per Customer	1.7153	1.7306

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER
Design Day: Heating Season 2020-2021

	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)

Docket No. G002/M-20-___
Attachment 1
Schedule 4

Customer Class	Jul-2019	Aug-2019	Sep-2019	Oct-2019	Nov-2019	Dec-2019	Jan-2020	Feb-2020	Mar-2020	Apr-2020	May-2020	Jun-2020	Total	Winter	Summer
Residential	745,015	656,685	646,930	1,543,878	3,361,324	5,522,305	7,188,633	5,864,656	5,757,108	3,731,270	2,115,409	1,106,781	38,239,996	27,694,026	10,545,969
Interdepartmental	158	210	257	293	610	1,231	1,462	1,396	1,262	957	772	490	9,098	5,961	3,137
Small Commercial Firm	107,088	79,341	83,671	174,819	435,261	829,820	1,071,644	925,968	910,159	527,817	276,209	135,237	5,557,033	4,172,851	1,384,182
Large Commercial Firm	416,792	369,627	381,605	694,907	1,449,654	2,400,613	3,010,050	2,503,761	2,549,944	1,596,210	949,687	498,554	16,821,405	11,914,022	4,907,383
Commercial Firm	524,038	449,178	465,533	870,020	1,885,525	3,231,664	4,083,155	3,431,125	3,461,366	2,124,984	1,226,668	634,282	22,387,536	16,092,834	6,294,702
Small Commercial Demand Billed	4,577	4,388	5,005	5,056	8,850	10,543	13,455	14,012	14,509	7,720	6,866	4,611	99,591	61,368	38,223
Large Commercial Demand Billed	146,935	148,414	154,199	164,184	260,186	336,721	380,288	337,330	334,802	261,857	211,341	145,794	2,882,052	1,649,327	1,232,725
Large Demand Billed - Generation	1,851	1,510	1,410	1,334	1,213	1,580	1,364	1,630	1,195	1,012	1,205	1,521	16,825	6,982	9,842
Commercial Demand Billed	153,364	154,312	160,613	170,574	270,248	348,845	395,107	352,972	350,505	270,589	219,412	151,926	2,998,467	1,717,677	1,280,790
Total Commercial Firm	677,402	603,489	626,146	1,040,593	2,155,773	3,580,509	4,478,263	3,784,096	3,811,871	2,395,573	1,446,081	786,208	25,386,003	17,810,512	7,575,491
Total Firm	1,422,417	1,260,174	1,273,076	2,584,471	5,517,097	9,102,814	11,666,895	9,648,753	9,568,979	6,126,842	3,561,490	1,892,989	63,625,999	45,504,538	18,121,461
Small Interruptible	69,060	60,268	59,879	94,921	191,319	321,539	349,849	296,405	292,293	204,146	139,024	69,540	2,148,241	1,451,404	696,837
Medium Interruptible	263,438	308,913	293,093	413,418	493,275	663,746	708,228	701,400	637,201	533,251	445,012	323,968	5,784,941	3,203,849	2,581,092
Large Interruptible	145,227	190,335	262,417	48,763	238,388	249,520	365,474	384,438	319,101	223,336	229,560	134,227	2,790,785	1,556,921	1,233,864
Med. & Lg. Interruptible - Generation	12,611	9,178	12,097	11,292	17,167	19,131	18,205	14,938	12,093	11,033	3,113	2,617	143,474	81,534	61,941
Total Interruptible	490,335	568,693	627,486	568,394	940,149	1,253,936	1,441,756	1,397,180	1,260,687	971,765	816,709	530,351	10,867,441	6,293,708	4,573,733
Total Firm and Interruptible	1,912,752	1,828,867	1,900,562	3,152,865	6,457,246	10,356,750	13,108,651	11,045,933	10,829,667	7,098,608	4,378,199	2,423,341	74,493,440	51,798,246	22,695,194
Firm Transportation	50,037	47,870	44,261	43,644	46,354	46,445	58,338	59,659	55,633	44,417	33,742	27,199	557,599	266,429	291,170
Interruptible Transportation	332,606	332,980	316,361	354,531	395,475	422,546	430,584	455,979	426,752	427,792	384,530	354,182	4,634,318	2,131,336	2,502,982
Negotiated Transporation	488,139	476,788	503,148	530,043	646,113	647,253	685,055	711,653	633,538	638,783	630,773	674,074	7,265,360	3,323,612	3,941,748
Interdepartmental Transport - Generation	4,753,555	4,494,405	3,033,139	3,711,170	2,231,239	3,287,588	4,035,301	2,220,437	2,148,875	2,819,996	2,848,926	2,848,926	38,433,557	13,923,440	24,510,117
Total Transportation	5,624,337	5,352,043	3,896,909	4,639,388	3,319,181	4,403,832	5,209,278	3,447,728	3,264,798	3,930,988	3,897,971	3,904,381	50,890,834	19,644,817	31,246,017
Total Customer Sales	7,537,089	7,180,910	5,797,471	7,792,253	9,776,427	14,760,582	18,317,929	14,493,661	14,094,465	11,029,596	8,276,170	6,327,722	125,384,274	71,443,063	53,941,211
Monthly Heating Degree Days	0	2	58	584	1,013	1,285	1,362	1,250	843	610	227	3	7,235	5,752	1,483

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2020-2021 Heating Season

Firm Supplies (1)	Current Quantity Effective Nov-20 Dth/Day	Proposed Quantity Effective Nov-21 Dth/Day	Proposed Quantity Change Nov-21 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)			
B. Minnesota Company Delivered Supply			
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	905,371	908,042	2,671
C. Minnesota State Delivered Supply			
State of MN Allocators	87.57%	87.18%	
TOTAL	792,833	791,631	(1,202)

(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: 2020/2021	469,350	749,192	791,631	Unknown	Unknown	Unknown
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.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Docket No. G002/M-20-___
Attachment 2
Schedule 1

Northern States Power Company
COMPANY DEMAND PROFILE
2020-2021 Heating Season

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		11.47%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%
112182	NNG TF12 BASE (Disc)	19,341	1,315	20,656	10 yrs - 10/31/27	Annual Re-Determination	2.27%
112182	NNG TF12 VARIABLE (Disc.)	75,186	(1,315)	73,871	10 yrs - 10/31/27	Annual Re-Determination	8.14%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		6.87%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.26%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 10/31/22		3.14%
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27		6.41%
112185	NNG TFX (Disc. 12-month)	36,654	0	36,654	10 yrs - 10/31/27		4.04%
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/27		Summer Only
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/27		Summer Only
112186	NNG TFX (Max)	57,491	0	57,491	10 yrs - 10/31/27		6.33%
112186	NNG TFX 2 (Max)	16,436	0	16,436	10 yrs - 10/31/27		Summer Only
112186	NNG TFX 5 (Max)	35,739	0	35,739	10 yrs - 10/31/27		Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.75%
122067	NNG TFX (Disc. Nov-Mar)	13,673	0	13,673	10 yrs - 10/31/27		1.51%
122067	NNG TFX 7 (Disc)	13,673	0	13,673	10 yrs - 10/31/27		Summer Only
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/27		0.98%
122068	NNG TFX 7 (Max)	8,875	0	8,875	10 yrs - 10/31/27		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.	29,002	0	29,002	5 yrs - 10/31/23		3.19%
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/23		0.47%
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/24		1.10%
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/22		1.72%
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/21		0.21%
AF0217	VGT FT-A 12 Mos.	72,213	0	72,213	5 yrs - 10/31/24		7.95%
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/24		1.65%
AF0329	VGT FT-A 12 Mos.	20,200	0	20,200	5 yrs - 10/31/23		2.22%
AF0353	VGT FT-A 12 Mos.	1,500	0	1,500	1 yrs - 10/31/21		0.17%
	WBI FT-1097	8,000	0	8,000	6.5 yrs - 10/31/25		0.88%
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/22		2.64%
	City Gate Deliveries	11,000	(11,000)	0	1 yrs - 2/28/20	Contract expiration	0.00%
	City Gate Deliveries		13,671	13,671	3 mos - 2/29/21	Seasonal Acquisition	1.51%
	LP Peak Shaving	90,000	0	90,000			9.91%
	LNG Peak Shaving	156,000	0	156,000			17.18%
	Total Design Day Capacity	**905,371**		**908,042**			**100%**
	Heating Season Total	905,371		908,042			
	Non-Heating Season Total	491,061		491,061			

COMPANY DEMAND PROFILE

2020-2021 Heating Season

Miscellaneous Entitlements with Reservation Fees

Additional Pipeline Entitlements					
ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/21	
ANR FTS-106211 (Summer) (1)	5,452	(4)	5,448	3 yrs - 03/31/21	Fuel Adjustment
ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/21	
ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	5 yrs - 10/31/2023	
GLT FT1718539 (Winter) (2)	3,509	0	3,509	2 yrs - 03/31/23	Contract Extension
GLT FT1718539 (Summer) (2)	5,370	0	5,370	2 yrs - 03/31/23	Contract Extension
GLT Backhaul FT18129 (Nov-Mar) (2)	9,248	0	9,248	2 yrs. - 03/31/23	Contract Extension
NNG SMS (3)	30,650		30,650	5 yrs - 10/31/22	
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	15,276	(12)	15,264	3 yrs - 3/31/21	Fuel adjustment
ANR Storage	9,248	0	9,248	2 yrs - 3/31/23	Contract Extension
FDD Service (5)	140,230	0	140,230	5 yrs - 5/31/23	
FDD Service	78,050	0	78,050	15 yrs - 5/31/27	
Storage Entitlements - Capacity					
ANR Pipeline Storage	947,112	(744)	946,368	3 yrs - 3/31/21	Fuel adjustment
ANR Storage	1,165,000	0	1,165,000	2 yrs - 3/31/23	
FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/23	
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 155,000 Dth in May 2022, 1,400,000 Dth in May 2023 & 6,529,975 Dth in May 2023

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2020

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	905,371	2,671	908,042
Non-Heating Season	491,061	-	491,061
Heating Season Forecasted Design Day	849,248	9,503	858,751
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	56,123	(6,832)	49,291
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.6%	-0.9%	5.7%
Total MN State Available Capacity:			
State of MN Allocation Factor	87.57%	-0.39%	87.18%
State of MN Heating Season Capacity	792,833	(1,202)	791,631
State of MN Design Day Demand	743,696	5,496	749,192
State of MN Heating Season Capacity Reserve/(Shortage)	49,137	(6,698)	42,439
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.6%	-0.9%	5.7%

(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, 2020

$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-19-498)	Last Month PGA: July 2020	Estimated Nov 2020 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)	$5.5042	$2.0982	$1.6068	$2.4442	-55.59%	16.49%	52.12%	$0.8374
Demand Cost of Gas (1)	$0.9008	$1.0117	$0.8983	$0.9426	4.64%	-6.83%	4.93%	$0.0443
Distribution Margin	$1.8591	$1.8591	$1.7600	$1.7600	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$4.9690	$4.2651	$5.1468	-37.72%	3.58%	20.67%	$0.8817
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$432.08	$370.86	$447.53	-37.72%	3.58%	20.67%	$76.67
Average Annual Total Demand Cost of Gas	$78.33	$87.97	$78.11	$81.96				**$3.85**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.0982	$1.6068	$2.4442	-55.46%	16.49%	52.12%	$0.8374
Demand Cost of Gas (1)	$0.8984	$1.0343	$0.9177	$0.9649	7.40%	-6.71%	5.14%	$0.0472
Distribution Margin	$1.2331	$1.2331	$1.1673	$1.1673	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.3656	$3.6918	$4.5764	-39.93%	4.83%	23.96%	$0.8846
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,239.94	$1,048.57	$1,299.82	-39.93%	4.83%	23.96%	$251.25
Average Annual Total Demand Cost of Gas	$255.17	$293.77	$260.65	$274.06				**$13.41**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.0982	$1.6068	$2.4442	-55.46%	16.49%	52.12%	$0.8374
Demand Cost of Gas (1)	$0.8917	$0.9928	$0.8820	$0.9256	3.80%	-6.77%	4.94%	$0.0436
Distribution Margin	$1.2315	$1.2315	$1.1658	$1.1658	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.3225	$3.6546	$4.5356	-40.40%	4.93%	24.11%	$0.8810
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$6,322.27	$5,345.39	$6,633.98	-40.40%	4.93%	24.11%	$1,288.59
Average Annual Total Demand Cost of Gas	$1,304.24	$1,452.11	$1,290.05	$1,353.82				**$63.77**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-19-498)	Last Month PGA: July 2020	Estimated Nov 2020 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								
Commodity Cost of Gas (WACOG)	$5.4926	$2.0982	$1.6068	$2.4442	-55.50%	16.49%	52.12%	$0.8374
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9121	$0.9121	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.0617	$2.5189	$3.3563	-48.01%	9.62%	33.24%	$0.8374
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$24,298.28	$19,990.56	$26,636.26	-48.01%	9.62%	33.24%	$6,645.69
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible								
Commodity Cost of Gas (WACOG)	$5.4696	$2.0982	$1.6068	$2.4442	-55.31%	16.49%	52.12%	$0.8374
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4498	$0.4498	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$2.5733	$2.0566	$2.8940	-51.32%	12.46%	40.72%	$0.8374
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$166,517.54	$133,079.69	$187,267.20	-51.32%	12.46%	40.72%	$54,187.50
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible								
Commodity Cost of Gas (WACOG)	$5.5006	$2.0982	$1.6068	$2.4442	-55.56%	16.49%	52.12%	$0.8374
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4114	$0.4114	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$2.5328	$2.0182	$2.8556	-51.89%	12.75%	41.49%	$0.8374
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$1,889,423.87	$1,505,557.83	$2,130,240.91	-51.89%	12.75%	41.49%	$624,683.08
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	$0.8374	52.12%	$0.0443	4.93%	$3.85	$76.67	20.67%
Small Commercial	$0.8374	52.12%	$0.0472	5.14%	$13.41	$251.25	23.96%
Large Commercial	$0.8374	52.12%	$0.0436	4.94%	$63.77	$1,288.59	24.11%
Small Interruptible	$0.8374	52.12%	$0.0000	NA	$0.00	$6,645.69	33.24%
Medium Interruptible	$0.8374	52.12%	$0.0000	NA	$0.00	$54,187.50	40.72%
Large Interruptible	$0.8374	52.12%	$0.0000	NA	$0.00	$624,683.08	41.49%

DERIVATION OF CURRENT PGA COSTS

Nov 2020 - Projected Costs (Actual prices will be determined Nov.1, 2020)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$35,971,029	$30,683,730	
2.	x Minnesota Design Day Ratio (2019 Demand Entitlement Filing)	87.18%	87.18%	
3.	Annual System Demand Allocation to MN	$31,359,543	$26,750,076	
4.	MN State Design Day (2019 Demand Entitlement Filing)	749,192	749,192	
5.	- Small & Large Demand Billed Dth (2019 Demand Entitlement Filing)	25,775	25,775	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	723,417	723,417	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$30,280,652	$25,829,769	
8.	Demand Billed Cost Allocation (3 - 7)	$1,078,891	$920,307	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	596,975,948	452,165,311	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.05072	$0.05712	$0.10784
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	$0.10784
14.	Total Demand Rate -Commercial (10 + 12)			$0.10784
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$1,078,891	$920,307	$1,999,198
16.	/ Annual Contract Billing Demand (2019 Demand Entitlement Filing)			3,093,017
17.	Monthly Commercial Demand Billed Demand Rate			$0.64636

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$22,172,248
19.	x MN Portion of Monthly Retail Sales	86.03%
20.	MN Portion of Monthly Commodity Costs	$19,074,785
21.	MN Budgeted Calendar Month Retail Therm Sales	78,040,310
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.24442

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.35226**
24.	Small & Large Commercial (14 +22)	**$0.35226**
25.	Small & Large Demand Billed - Demand (17)	**$0.64636**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.24442**

*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 No. G002/M-16-88 (Order dated April 22, 2016) and G002/M-19-703 (Order dated February 12, 2020) Regarding benefits of the contracts.

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

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

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

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

CERTIFICATE OF SERVICE

I, Paget Pengelly, 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-06-1429
G002/GR-09-1153
Xcel Energy Misc. Gas Service List

Dated this 31st day of July 2020

/s/

____

Paget Pengelly
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_6-1429_1
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_6-1429_1
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_6-1429_1
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_6-1429_1
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_6-1429_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_6-1429_1
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_6-1429_1
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_6-1429_1
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_6-1429_1
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_6-1429_1
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_6-1429_1
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_6-1429_1
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_6-1429_1
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_6-1429_1
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_9-1153_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_9-1153_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_9-1153_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_9-1153_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_9-1153_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_9-1153_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_9-1153_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_9-1153_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_9-1153_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1153_Official

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Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
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Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
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Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
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James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas