414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

August 1, 2016

—Via Electronic Filing—

Daniel P. Wolf
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-16-___

Dear Mr. Wolf:

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, Subd. 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) 330-6613 or amy.a.liberkowski@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

AMY A. LIBERKOWSKI
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John 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-16-____

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 7,747 Dekatherms, with an increase in demand related costs of approximately $932,000 for the 2016-2017 year. 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 2016-2017 Heating Season Supply Plan effective November 1, 2016, 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, 2016.

New requirements since our last Contract Demand Entitlement Petition (Docket No. G002/M-15-727), are listed below and included in this filing.

Order Point 4 of the Commission's October 16, 2015 Order in Docket No. G002/M-14-654 states:

> *Require Xcel to provide its storage entitlements (reservation and capacity), by contract, in future demand entitlement petitions, beginning with Xcel's 2016-2017 demand entitlement petition to be filed by August 1, 2016.*

Order Point 2 of the Commission's April 22, 2016 Order in Docket No. G002/M-16-88 requires 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 contracts to Xcel's ratepayers.*

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 Order dated April 22, 2016 in Docket No. G002/M-16-88 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, Minnesota 55401
(612) 330-5500

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

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
(612) 215-4662

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on August 1, 2016. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2016 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, 2016, 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 Tariff 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

Amy A. Liberkowski
Director, Regulatory Pricing & Analysis
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-6613

IV. 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, 2016, and respectfully request Commission approval of the revised entitlements effective on November 1, 2016. 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 2015-2016 heating season, as described in Attachment 1.

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 2015-2016 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.

D. Change in Supply Reservation Fees

This filing also reflects updated costs for firm gas supply reservation fees.

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 No. G002/M-16-88 (Order dated April 22, 2016) regarding benefits to customers. The attachment discusses the anticipated benefits of the contracts to

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

ratepayers and shows a summary of hedge transactions for the 2016-2017 heating season.

F. Classification and Billing of Demand Costs

In the Company's 2007 Contract Demand Entitlement filing[2] and with updates in subsequent Contract Demand Entitlement filings, we included a proposal to assign some demand costs – storage capacity demand charges and pipeline balancing charges – to interruptible customers. These requested changes have been settled as described below.

In the 2012 natural gas Automatic Annual Adjustment filing,[3] the Commission ordered:

> *Prospectively, all regulated natural gas utilities shall recover balancing service costs, and shall credit the utility's penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented.*

We began treating pipeline balancing charges as commodity costs instead of demand costs in our November 2013 PGA.

In our grouped 2007-2013 Contract Demand Entitlement filings,[4] the Commission ordered:

> *Require Xcel to allocate some storage-capacity demand charges to interruptible sales customers by including the costs in the commodity cost of gas withdrawn from storage and delivered to firm- and interruptible-sales customers, effective July 1, 2014.*

We began treating storage-capacity demand charges as commodity costs instead of demand costs in our July 2014 PGA.

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.

---

[2] Docket No. G002/M-07-1395.
[3] Docket No. G002/AA-12-756, Order dated November 14, 2013.
[4] Docket Nos. G002/M-07-1395, G002/M-08-1315, G002/M-09-1287, G002/M-10-1163, G002/M-11-1076, G002/M-12-862, and G002/M-13-663, Order dated June 9, 2014.

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	Demand Profile, Storage Entitlements
1, page 2	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 No. G002/M-16-88 (Order dated April 22, 2016) regarding benefits to customers.

Schedule	Title
1	Summary of Hedge Transactions

V. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

As calculated in Trade Secret **Attachment 1, Schedule 2, Page 1 of 2**, the effect of the proposed changes in demand cost upon Xcel Energy's Minnesota State annual revenue is an increase of $932,308.26 or about two percent of the total Minnesota State demand costs, effective November 1, 2016. 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**.

VI. 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:

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, Minnesota 55401
Alison.C.Archer@xcelenergy.com

Carl Cronin
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, Minnesota 55401
Regulatory.Records@xcelenergy.com

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2016-2017 Heating Season Supply Plan effective November 1, 2016, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2016 usage. Approval will enable us to provide continued reliable and competitive service for our natural gas customers in Minnesota. The Company will provisionally reflect the change in entitlement costs associated with the revised contract demand entitlements in the Company's November PGA, subject to later Commission approval.

Dated: August 1, 2016

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John 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-16-____

PETITION

SUMMARY OF FILING

Please take notice that on August 1, 2016, 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 2016-2017 Heating Season Supply Plan effective November 1, 2016. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2016, 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 for 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.

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

Our forecasted firm customer count in Minnesota State increased by 3,814 customers, from 450,444 forecast for the 2015-2016 heating season to 454,258 forecast for the 2016-2017 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 7,747 Dekatherms (Dth), from 717,478 to 725,225, using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**.

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 4**. The Avg. Monthly DD calculation is based on linear regression using 60 data points, from January 2010-December 2015, as shown on **Attachment 1, Schedule 1, Pages 2-4**. Nearly 70% of all regression statistics were very strong with R-squared values at or above 95 percent.[2] The regions with R-squared values below 95 percent were generally those with much lower customer counts. In all, R-squared values were, on average, 91 percent. 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.

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 702,546 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 22,679 Dth is added to the DD estimate for the Residential, Small and Large Commercial classes a to determine the total Minnesota State DD Projection of 725,225 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 will 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.

We note that the Commission has asked the Department to examine whether the inclusion of telemetered data would yield cost savings, as it did for MERC. Our

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

methods exclude interruptible customers throughout the process and therefore no change to the use of telemetered data is necessary. While NSP does have a requirement that all interruptible customers have the ability to telemeter, as discussed in our compliance filing in Docket No. G002/M-14-654, we currently do not believe that a switch to a new method in order to begin utilizing telemetered data would be likely to result in substantially better results given our current methodology.

2. Change in Resources to Meet Design Day

Attachment 2, Schedule 1, Page 1 of 2 details the demand entitlement changes to meet the increased DD in Minnesota State for the 2016-2017 heating season compared to the 2015-2016 heating season as filed in Docket No. G002/M-15-727. **Attachment 1, Schedule 2** details the demand cost component changes for the 2016-2017 heating season. The projected DD for the Company increased by 8,819 Dth/day (7,747 Dth/day for Minnesota) for the 2016-2017 heating season. The demand entitlement changes discussed below represent a combination of renewals of existing contract entitlements and new, incremental contracts to serve the growth in projected DD. **Attachment 1, Schedule 2, Page 2 of 2** also shows the year-to-year demand cost changes allocated by jurisdiction or upstream/system supply. The schedule shows an increase of demand related total costs of approximately $1,059,682 ($932,308 for Minnesota), including contract demand and supplier entitlement changes. This increase is largely attributable to an active rate case proceeding at the Federal Energy Regulatory Commission on an upstream pipeline and, to a lesser extent, added entitlements due to on-system growth. The outcome of the rate case proceeding will be incorporated once the final decision is known.

a. Change in Northern Natural Gas (Northern) entitlement (effective November 1, 2016)

One modification was made to firm capacity entitlement levels on Northern in the past year. We added 1,539 Dth/day of incremental capacity at St. Cloud, Minnesota to be effective November 1, 2016.

In addition, the Company exercised its unilateral right on 8 long-term transportation contracts for a ten-year extension. This extension renews long term capacity at a slight ($0.01/Dth) rate increase from the currently effective discount beginning November 1, 2017. These transportation agreements continue to be necessary to serve firm customers in central and northern Minnesota. The discount extension provision required one-year advanced notice, even though the cost increase will not take effect until the following winter season.

b. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2016)

NSP plans to acquire one additional Viking firm contract for November 2016 through March 2017. We plan to purchase 16,371 Dth/day of capacity for this winter consistent with our practice over the last several years of acquiring some short-term capacity to address a small portion of our overall DD projections. The capacity is available to serve Grand Forks/East Grand Forks area, the Fargo/Moorhead area, and the Minneapolis/St. Paul metro area (through Northern) throughout the winter. We keep these costs low by only purchasing this capacity for the winter, since it is not needed on a year-round basis. As demand continues to grow on our system, it may be necessary to acquire the Viking capacity on a year-round basis to insure that the capacity will be available whenever it is needed by our customers.

c. Change in Great Lakes Gas Transmission (Great Lakes) entitlement (effective November 1, 2016)

NSP renewed two Great Lakes firm capacity entitlements this year. The previous capacity of 9,248 Dth/ expired March 31, 2017 and has been renewed on a winter-only basis for a one-year term. We also renewed summer capacity of 895 Dth/day for the same term. This capacity supports the winter withdrawal and summer injection of the ANR Storage quantities described below.

d. Change in ANR Storage entitlement (effective April 1, 2016)

We renewed our contract with ANR Storage for one-year until March 31, 2018 at the existing contract entitlements. Natural gas withdrawn from the ANR Storage facility is transported on Great Lakes to the Carlton, Minnesota interconnect with Northern for downstream deliveries generally to the greater Minneapolis/St. Paul metro area. The extension of this contract provides for greater supply flexibility and natural gas supply price protection in winter months. Flexibility and price protection are particularly important as a balance against the challenging supply availability and unusual natural gas price volatility at the Emerson supply point near the Minnesota/Canadian border.

e. Change in ANR Pipeline entitlement (effective April 1, 2016)

Small reductions were made to entitlement holdings on ANR Pipeline pursuant to ANR Pipeline's tariff. These are annual adjustments to match the changes in ANR's in-kind fuel percentages made each spring by the Federal Energy Regulatory

Commission. These volume changes maintain our delivery quantities in response to changes in fuel requirements and do not materially impact demand costs.

In January 2016 ANR Pipeline Company filed a rate case (Docket No. RP16-440) with the Federal Energy Regulatory Commission (FERC) proposing an increase in rates to become effective August 1, 2016 subject to refund. NSP is an active participant in this case to ensure a just and reasonable outcome for our customers.

3. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 87.99 percent to 87.98 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 4**. 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.

4. Change in Supplier Reservation Fees

The total change in supplier reservation charges is a decrease of $221,250. **Attachment 1, Schedule 2** lists the changes in Supply Entitlements.

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**.

We propose to return our capacity reserve margin from 2.9 percent in November 2015 to the more typical level of 5.6 percent in November 2016, as described in **Attachment 2, Schedule 1, Page 2 of 2**. This increase in reserve margin represents a return to full operating capacity of the Sibley Propane Plant, which experience reduced operating conditions during the 2015-16 heating season. 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 2016-2017 heating season DD reserve margin for Minnesota State is 40,309 Dth/day or 5.6 percent.

C. 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**.

D. 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.**

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2016-2017 Heating Season

Service Region (1)	Projected Jan 2017 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	318,688	75	11,266	0.0326696	91	1.2274322	1.009	502,698	513,964	
BRAINERD	16,653	3	360	0.0203813	91	1.1448098	1.009	20,139	20,499	
MAINLINE	15,431	12	3,092	0.0346839	88	1.3346682	1.009	23,919	27,011	
MAINLINE-WELCOME	2,364	0	0	0.0167097	88	0.9027110	1.009	2,630	2,630	
WILLMAR	10,491	2	363	0.0212006	88	0.8865923	1.009	12,863	13,225	
PAYNESVILLE	42,446	24	3,060	0.0400341	94	1.0898660	1.009	72,011	75,071	
VGT-CHISAGO	2,091	0	0	0.0126586	91	1.2002485	1.009	2,240	2,240	
WATKINS	7,649	1	306	0.0168630	94	1.0583328	1.009	9,196	9,501	
TOMAH	15,497	10	1,556	0.0355455	88	0.5157317	1.009	23,144	24,700	
RED WING	7,682	5	673	0.0344500	88	1.2293880	1.009	11,816	12,489	
GRAND FORKS MN	2,968	1	63	0.0308129	98	0.3582932	1.009	4,511	4,575	
FARGO MN	12,297	5	1,940	0.0300622	98	0.2731514	1.009	17,379	19,319	
MN State	**454,258**	**138**	**22,679**					**702,546**	**725,225**	**87.98%**
GRAND FORKS ND	16,080	0	0	0.0160696	98	1.7700881	1.009	29,085	29,085	
FARGO ND	37,778	0	0	0.0160567	98	1.8833994	1.009	68,434	68,434	
WBI ND	1,177	0	0	0.0114199	98	1.5544349	1.009	1,526	1,526	
ND State	55,035	0	0					99,044	99,044	12.02%
TOTAL	**509,293**	**138**	**22,679**					**801,590**	**824,269**	**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 2011 to December 2015.
(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
2016-2017 Heating Season

Division/Region (1)	Projected Firm Jan 2017 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) 2017 Unacc. Volume	Load Variation	Day Base	Total	2016 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO														
Total Residential	296,538	0.0104398	91	1.1473849	0.9867	0.0090	2,636	281,719	11,192	**295,547**	293,533	2,015	28,879	**324,426**
Total Small Commercial	15,398	0.0367334	91	2.8730980	0.9590	0.0090	476	51,471	1,455	**53,402**	56,280	(2,878)	5,218	**58,621**
Total Large Commercial	6,752	0.1667129	91	25.1694187	0.9821	0.0090	972	102,438	5,591	**109,001**	85,158	23,843	10,651	**119,652**
Industrial	75	Contract Demand	-	-		-	-	-	-	**11,266**	14,426	(3,160)	-	**11,266**
	318,763	0.0326696		1.227432152			4,085	435,628	18,238	**469,217**	449,397	19,820	44,748	**513,964**
												4.4%		
BRAINERD														
Total Residential	15,385	0.0094458	91	0.8669843	0.9873	0.0090	123	13,225	439	**13,787**	13,340	446	1,347	**15,134**
Total Small Commercial	1,099	0.0231125	91	5.0201718	0.9320	0.0090	22	2,310	181	**2,514**	2,567	(53)	246	**2,760**
Total Large Commercial	169	0.1158309	91	45.0865959	0.9567	0.0090	18	1,777	250	**2,046**	1,535	511	200	**2,246**
Industrial	3	Contract Demand	-	-		-	-	-	-	**360**	118	242	-	**360**
	16,656	0.0203813		1.144809839			164	17,313	870	**18,707**	17,560	1,147	1,793	**20,499**
												6.5%		
MAINLINE														
Total Residential	13,965	0.0099710	88	1.1573685	0.9849	0.0090	115	12,254	532	**12,900**	12,575	325	1,261	**14,161**
Total Small Commercial	1,102	0.0294538	88	3.6752412	0.8940	0.0090	27	2,856	133	**3,016**	3,153	(137)	295	**3,311**
Total Large Commercial	364	0.1687864	88	34.9364195	0.9366	0.0090	52	5,403	418	**5,873**	4,573	1,300	574	**6,447**
Industrial	12	Contract Demand	-	-		-	-	-	-	**3,092**	1,421	1,671	-	**3,092**
	15,443	0.0346839		1.334668224			194	20,512	1,083	**24,882**	21,722	3,159	2,129	**27,011**
												14.5%		
MAINLINE-WELCOME														
Total Residential	2,226	0.0095970	88	0.7486920	0.9764	0.0090	17	1,880	55	**1,952**	1,968	(16)	191	**2,143**
Total Small Commercial	123	0.0157693	88	2.7595984	0.5476	0.0090	2	170	11	**183**	193	(10)	18	**201**
Total Large Commercial	16	0.1402598	88	113.7661676	0.5268	0.0090	2	198	60	**261**	220	41	25	**286**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,364	0.0167097		0.902711037			21	2,248	126	**2,396**	2,381	15	234	**2,630**
												0.6%		
WILLMAR														
Total Residential	9,719	0.0095630	88	0.7843378	0.9848	0.0090	76	8,179	251	**8,506**	8,666	(160)	831	**9,337**
Total Small Commercial	663	0.0306666	88	2.3412313	0.9616	0.0090	17	1,788	51	**1,856**	1,989	(133)	181	**2,037**
Total Large Commercial	109	0.1327901	88	19.2519536	0.8482	0.0090	12	1,274	69	**1,356**	993	362	132	**1,488**
Industrial	2	Contract Demand	-	-		-	-	-	-	**363**	169	194	-	**363**
	10,493	0.0212006		0.886592291			105	11,242	371	**12,080**	11,817	263	1,145	**13,225**
												2.2%		
PAYNESVILLE														
Total Residential	37,656	0.0094125	94	0.8914497	0.9887	0.0090	310	33,317	1,104	**34,731**	34,103	628	3,394	**38,124**
Total Small Commercial	3,571	0.0352395	94	3.2131352	0.9669	0.0090	110	11,828	377	**12,315**	12,810	(495)	1,203	**13,518**
Total Large Commercial	1,220	0.1513555	94	25.7775803	0.9824	0.0090	166	17,355	1,034	**18,555**	14,458	4,097	1,813	**20,368**
Industrial	24	Contract Demand	-	-		-	-	-	-	**3,060**	2,476	584	-	**3,060**
	42,470	0.0400341		1.089865959			585	62,500	2,516	**68,661**	63,847	4,814	6,410	**75,071**
												7.5%		
VGT-CHISAGO														
Total Residential	1,993	0.0090915	91	1.0653655	0.9812	0.0090	15	1,649	70	**1,734**	1,658	76	169	**1,904**
Total Small Commercial	92	0.0278178	91	4.1803111	0.7850	0.0090	2	233	13	**248**	293	(46)	24	**272**
Total Large Commercial	6	0.1147641	91	(4.1104726)	0.8312	0.0090	1	59	(1)	**59**	37	22	6	**65**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,091	0.0126586		1.200248549			18	1,941	82	**2,041**	1,988	53	199	**2,240**
												2.7%		
WATKINS														
Total Residential	7,376	0.0092223	94	0.9740153	0.9827	0.0090	60	6,394	236	**6,690**	6,516	174	654	**7,344**
Total Small Commercial	221	0.0385913	94	3.3036363	0.8898	0.0090	7	802	24	**834**	903	(69)	81	**915**
Total Large Commercial	52	0.1266711	94	129.4593306	0.3965	0.0090	8	623	223	**853**	613	241	83	**937**
Industrial	1	Contract Demand	-	-		-	-	-	-	**306**	50	256	-	**306**
	7,650	0.0168630		1.058332842			75	7,819	483	**8,683**	8,082	601	819	**9,501**
												7.4%		
TOMAH														
Total Residential	13,908	0.0097350	88	0.4359155	0.9805	0.0090	109	11,915	199	**12,223**	12,157	66	1,194	**13,418**
Total Small Commercial	1,204	0.0255658	88	1.2727387	0.9547	0.0090	25	2,710	50	**2,785**	2,922	(137)	272	**3,057**
Total Large Commercial	385	0.1713813	88	17.1613524	0.9660	0.0090	54	5,804	217	**6,076**	4,577	1,499	594	**6,669**
Industrial	10	Contract Demand	-	-		-	-	-	-	**1,556**	1,906	(350)	-	**1,556**
	15,507	0.0355455		0.515731702			188	20,429	467	**22,640**	21,561	1,079	2,060	**24,700**
												5.0%		
RED WING														
Total Residential	6,930	0.0095512	88	0.9379127	0.9866	0.0090	54	5,825	214	**6,093**	6,016	77	595	**6,688**
Total Small Commercial	570	0.0290599	88	4.8228314	0.9514	0.0090	14	1,458	90	**1,562**	1,611	(49)	153	**1,715**
Total Large Commercial	182	0.1853553	88	19.1969284	0.9639	0.0090	28	2,967	115	**3,109**	2,404	705	304	**3,413**
Industrial	5	Contract Demand	-	-		-	-	-	-	**673**	568	106	-	**673**
	7,687	0.0344500		1.229388029			96	10,249	419	**11,438**	10,599	839	1,052	**12,489**
												7.9%		
GRAND FORKS MN														
Total Residential	2,652	0.0092069	98	0.2130597	0.9690	0.0090	22	2,393	19	**2,433**	2,402	32	238	**2,671**
Total Small Commercial	259	0.0382496	98	1.6533251	0.9434	0.0090	9	971	14	**994**	1,021	(27)	97	**1,091**
Total Large Commercial	57	0.1163945	98	13.4749346	0.9670	0.0090	6	651	25	**682**	529	153	67	**749**
Industrial	1	Contract Demand	-	-		-	-	-	-	**63**	38	26	-	**63**
	2,969	0.0308129		0.35829324			37	4,015	58	**4,173**	3,989	185	402	**4,575**
												4.6%		
FARGO MN														
Total Residential	11,083	0.0082095	98	0.0591620	0.9744	0.0090	80	8,917	22	**9,019**	8,717	301	881	**9,900**
Total Small Commercial	963	0.0291666	98	2.5268606	0.9488	0.0090	26	2,753	80	**2,859**	2,914	(55)	279	**3,138**
Total Large Commercial	251	0.1529470	98	19.8024221	0.9629	0.0090	35	3,756	163	**3,954**	3,104	851	386	**4,341**
Industrial	5	Contract Demand	-	-		-	-	-	-	**1,940**	1,125	814	-	**1,940**
	12,302	0.0300622		0.273151433			141	15,426	265	**17,772**	15,860	1,911	1,547	**19,319**
												12.1%		
MN COMPANY														
Total Residential	**419,432**									**405,615**	**401,652**	**3,964**	**39,634**	**445,249**
Total Small Commercial	**25,264**									**82,568**	**86,655**	**-4,087**	**8,068**	**90,636**
Total Large Commercial	**9,562**									**151,825**	**118,199**	**33,626**	**14,835**	**166,661**
Contract Demand	**138**									**22,679**	**22,295**	**383**	**0**	**22,679**
	454,396									**662,687**	**628,802**	**33,886**	**62,537**	**725,225**
												5.4%		

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2016-2017 Heating Season

Division/Region (1)	Projected Firm Jan 2016 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) 2017 Unacc. Volume	Load Variation	Day Base	Total	2016 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND														
Total Residential	13,941	0.0089226	98	0.4071553	0.9815	0.0090	111	12,191	187	**12,489**	12,026	463	1,220	**13,709**
Total Small Commercial	2,139	0.0626588	98	10.6546817	0.9484	0.0090	125	13,133	750	**14,007**	13,392	615	1,369	**15,376**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	16,080	0.0160696		1.770088056			236	25,323	936	**26,496**	25,418	1,078 4.2%	2,589	**29,085**
FARGO ND														
Total Residential	31,925	0.0085495	98	0.4113722	0.9821	0.0090	245	26,748	432	**27,425**	26,391	1,034	2,680	**30,105**
Total Small Commercial	5,853	0.0570044	98	9.9125504	0.9618	0.0090	311	32,697	1,908	**34,917**	32,352	2,565	3,412	**38,329**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	37,778	0.0160567		1.883399368			556	59,446	2,340	**62,342**	58,744	3,599 6.1%	6,092	**68,434**
WBI ND														
Total Residential	1,015	0.0095897	98	0.1576502	0.9590	0.0090	9	954	5	**967**	923	45	95	**1,062**
Total Small Commercial	162	0.0228578	98	10.2834603	0.3642	0.0090	4	364	55	**422**	391	31	41	**464**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	1,177	0.0114199		1.554434899			12	1,317	60	**1,390**	1,314	76 5.8%	136	**1,526**
ND COMPANY														
Total Residential	**46,881**									**40,881**	**39,340**	**1,541**	**3,995**	**44,876**
Total Small Commercial	**8,154**									**49,347**	**46,135**	**3,211**	**4,822**	**54,168**
Total Large Commercial	**0**									**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**									**-**	**-**	**-**	**-**	**-**
	55,035									**90,228**	**85,476**	**4,752** **5.6%**	**8,816**	**99,044**
Grand Total														
Total Residential	**466,313**									**446,497**	**440,992**	**5,505**	**43,628**	**490,125**
Total Small Commercial	**33,418**									**131,915**	**132,791**	**(876)**	**12,890**	**144,805**
Total Large Commercial	**9,562**									**151,825**	**118,199**	**33,626**	**14,835**	**166,661**
Contract Demand	**138**									**22,679**	**22,295**	**383**	**-**	**22,679**
	509,431									**752,915**	**714,278**	**38,638** **5.4%**	**71,353**	**824,269**

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2016-2017 Heating Season

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2017 FORECAST	2016 FORECAST	Difference	%Diff
METRO	318,688	316,505	2,183	0.7%
BRAINERD	16,653	16,346	307	1.9%
MAINLINE	15,431	15,084	346	2.3%
MAINLINE-WELCOME	2,364	2,371	(7)	-0.3%
WILLMAR	10,491	10,770	(279)	-2.6%
PAYNESVILLE	42,446	41,865	581	1.4%
VGT-CHISAGO	2,091	2,025	65	3.2%
WATKINS	7,649	7,523	126	1.7%
TOMAH	15,497	15,404	93	0.6%
RED WING	7,682	7,590	92	1.2%
GRAND FORKS MN	2,968	2,961	7	0.2%
FARGO MN	12,297	11,998	299	2.5%
MN STATE	454,258	450,444	3,814	0.8%
GRAND FORKS ND	16,080	15,719	361	2.3%
FARGO ND	37,778	36,622	1,156	3.2%
WBI ND	1,177	1,149	28	2.4%
ND STATE	55,035	53,490	1,545	2.9%
TOTAL NSP MN	509,293	503,934	5,359	**1.1%**

2017 Customer Counts

	MN	ND	
Res	419,432	46,881	**466,313**
Sm Com	25,264	8,154	**33,418**
Lg Com	9,562	0	**9,562**
Ind	138	0	**138**
	454,396	55,035	**509,431**

2017 Design Day Use By Customer Class

	MN	ND	
Res	445,249	44,876	**490,125**
Sm Com	90,636	54,168	**144,805**
Lg Com	166,661	0	**166,661**
Ind	22,679	0	**22,679**
	725,225	99,044	**824,269**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2017 FORECAST	2016 FORECAST	Difference	%Diff
METRO	513,964	512,993	972	0.2%
BRAINERD	20,499	20,110	389	1.9%
MAINLINE	27,011	24,690	2,320	9.4%
MAINLINE-WELCOME	2,630	2,729	(99)	-3.6%
WILLMAR	13,225	13,520	(295)	-2.2%
PAYNESVILLE	75,071	72,819	2,251	3.1%
VGT-CHISAGO	2,240	2,279	(38)	-1.7%
WATKINS	9,501	9,256	245	2.6%
TOMAH	24,700	24,435	265	1.1%
RED WING	12,489	12,066	424	3.5%
GRAND FORKS MN	4,575	4,566	8	0.2%
FARGO MN	19,319	18,015	1,304	7.2%
MN STATE	725,225	717,478	7,747	1.1%
GRAND FORKS ND	29,085	29,134	(49)	-0.2%
FARGO ND	68,434	67,332	1,102	1.6%
WBI ND	1,526	1,506	19	1.3%
ND STATE	99,044	97,973	1,071	1.1%
TOTAL NSP MN	824,269	815,451	8,819	1.1%

MN / ND Allocation Factors

2017 DD	2016 DD	
0.8798	0.8799	**MN State Allocation**
0.1202	0.1201	**ND State Allocation**

NNG SYSTEM	2017 FORECAST	2016 FORECAST	Difference	%Diff
METRO	513,964	512,993	972	0.2%
BRAINERD	20,499	20,110	389	1.9%
MAINLINE	27,011	24,690	2,320	9.4%
MAINLINE-WELCOME	2,630	2,729	(99)	-3.6%
WILLMAR	13,225	13,520	(295)	-2.2%
PAYNESVILLE	75,071	72,819	2,251	3.1%
WATKINS	9,501	9,256	245	2.6%
TOMAH	24,700	24,435	265	1.1%
RED WING	12,489	12,066	424	3.5%
NNG SUBTOTAL	699,091	692,618	6,473	0.9%

VGT SYSTEM

VGT-CHISAGO	2,240	2,279	(38)	-1.7%
GRAND FORKS MN	4,575	4,566	8	0.2%
FARGO MN	19,319	18,015	1,304	7.2%
GRAND FORKS ND	29,085	29,134	(49)	-0.2%
FARGO ND	68,434	67,332	1,102	1.6%
WBI ND	1,526	1,506	19	1.3%
VGT SUBTOTAL	125,178	122,833	2,345	1.9%
VGT & NNG TOTAL	824,269	815,451	8,818	1.1%

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company | Docket No. G002/M-16-____
DEMAND COST OF GAS IMPACT - NOVEMBER 2016 | 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
NNG TFX (Nov - Mar)[1]	1,539	$ 8.6272	5	$ 66,386.30
NNG TFX (Apr - Oct)[1]	1,539	$ 4.0000	7	$ 43,092.00
VGT FT-A (Dec - Feb)[2]	(12,428)	$ 4.7507	3	$ (177,125.10)
VGT FT-A (Dec - Feb)[2]	16,371	$ 4.7507	5	$ 388,868.55
ANR FSS (Jan - Dec)[4]	(44)	$ 1.7820	12	$ (940.90)
ANR FSS (Jan - Dec)[4]	(15,300)	$ 1.7820	12	$ (327,175.20)
ANR FSS (Jan - Dec)[4]	15,300	$ 0.6801	12	$ 124,866.36
ANR FTS (Jan - Dec)[3]	(4,829)	$ 9.4000	12	$ (544,711.20)
ANR FTS (Jan - Dec)[3]	4,829	$ 22.5453	12	$ 1,306,455.04
ANR FTS (Nov - Mar)[3]	(15,171)	$ 4.4000	5	$ (333,762.00)
ANR FTS (Nov - Mar)[3]	15,171	$ 8.0342	5	$ 609,434.24
ANR FTS (Apr - Oct)[3]	(4,935)	$ 4.4000	7	$ (151,998.00)
ANR FTS (Apr - Oct)[3]	4,935	$ 8.0342	7	$ 277,541.44
Total				$ 1,280,931.54

Supplier Entitlement Changes

Change in Supplier Reservation Fees

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Total	(14,500)	($221,249.50)

Total MN & ND Demand Cost Adjustment	**$1,059,682.04**
Minnesota Allocation Factor (MN/ND Allocated Demand)	87.98%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand	**$ 932,308.26**

[1] NNG Sixth Revised Volume No. 1, Eleventh Revised Sheet No. 51, Effective April 1, 2016

[2] VGT Volume No. 1, Part 5.0 Statement of Rates, Effective April 1, 2016

[3] ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v. 1.0.0, Effective August 1, 2016 subject to refund (RP16-440)

[4] ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 1.0.0, Effective August 1, 2016 subject to refund (RP16-440)

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-16-____
Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2015 SUPPLEMENTAL FILED COSTS				**$31,259,124.08**	**$23,382,206.94**	**$54,641,331.02**				
2015 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total					$ -	$ -				
2015 ACTUAL COSTS				**$ 31,259,124.08**	**$ 23,382,206.94**	**$ 54,641,331.02**				
CHANGES FOR 2016 FILING										
Contract Demand Entitlement Changes										
NNG TFX (Nov - Mar)	1,539	$ 8.6272	5		$ 66,386.30	$ 66,386.30	$ 66,386.30			1
NNG TFX (Apr - Oct)	1,539	$ 4.0000	7	$ 43,092.00		$ 43,092.00	$ 43,092.00			1
VGT FT-A (Dec - Feb)	(12,428)	$ 4.7507	3		$ (177,125.10)	$ (177,125.10)		$ (177,125.10)		2
VGT FT-A (Dec - Feb)	16,371	$ 4.7507	5		$ 388,868.55	$ 388,868.55		$ 388,868.55		3
ANR FSS (Jan - Dec)	(44)	$ 1.7820	12		$ (940.90)	$ (940.90)			$ (940.90)	4
ANR FSS (Jan - Dec)	(15,300)	$ 1.7820	12		$ (327,175.20)	$ (327,175.20)			$ (327,175.20)	5
ANR FSS (Jan - Dec)	15,300	$ 0.6801	12		$ 124,866.36	$ 124,866.36			$ 124,866.36	5
ANR FTS (Jan - Dec)	(4,829)	$ 9.4000	12	$ (544,711.20)		$ (544,711.20)			$ (544,711.20)	5
ANR FTS (Jan - Dec)	4,829	$22.5453	12	$ 1,306,455.04		$ 1,306,455.04			$ 1,306,455.04	5
ANR FTS (Nov - Mar)	(15,171)	$ 4.4000	5		$ (333,762.00)	$ (333,762.00)			$ (333,762.00)	5
ANR FTS (Nov - Mar)	15,171	$ 8.0342	5		$ 609,434.24	$ 609,434.24			$ 609,434.24	5
ANR FTS (Apr - Oct)	(4,935)	$ 4.4000	7		$ (151,998.00)	$ (151,998.00)			$ (151,998.00)	5
ANR FTS (Apr - Oct)	4,935	$ 8.0342	7		$ 277,541.44	$ 277,541.44			$ 277,541.44	5
Total				$ 804,835.84	$ 476,095.70	$ 1,280,931.54	$ 109,478.30	$ 211,743.45	$ 959,709.79	
Supplier Entitlement Changes										
[TRADE SECRET BEGINS										
										6
										6
										6
										6
										6
									TRADE SECRET ENDS]	
Total				$ -	$ (221,249.50)	$ (221,249.50)	$ (221,249.50)	$ -	$ -	
TOTAL OF 2016 CHANGES				**$ 804,835.84**	**$ 254,846.20**	**$ 1,059,682.04**	**$ (111,771.20)**	**$ 211,743.45**	**$ 959,709.79**	
2016 COSTS				**$ 32,063,959.92**	**$ 23,637,053.14**	**$ 55,701,013.06**				
2016 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							-35%	65%		7

Footnote
1. Incremental capacity added near St. Cloud, MN starting November 1, 2016.
2. Expired winter firm transport capacity, December 1, 2015 through February 28, 2016.
3. Renewed firm transport capacity serving Fargo, ND, December 1, 2016 through February 28, 2017.
4. Volume additions on ANR transport and storage agreements. Upstream capacity serves demand in both MN and ND.
5. Rate increase subject to refund as filed in ANR FERC rate case (RP16-440)
6. Expired peaking supply contract with demand charges in effect November 1, 2015 through March 31, 2016.
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.

SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS

Design Day: Heating Season 2016-2017

DESIGN DAY CALCULATION

State of Minnesota	Jan-2017 Budget Customer	2017 MMBtu Design Day[1]	2016 MMBtu Design Day[1]	MMBtu Change
Residential	419,432	445,249	460,376	(15,127)
Commercial	34,826	257,297	234,806	22,491
Demand Billed	138	22,679	22,295	383
State of Minnesota Total	**454,396**	**725,225**	**717,478**	**7,747**
State of North Dakota Total	55,035	99,044	97,973	1,071
Total Xcel Energy - Gas Utility Operations	509,431	824,269	815,451	8,818

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

Minnesota Company	Jan-2017 Budget Customer	Jan-2016 Budget Customer	Change
Residential	466,313	461,635	4,678
Commercial	42,980	42,299	681
TOTAL	509,293	503,934	5,359
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	801,590	793,156	
Demand Billed Customers	138	186	
Contracted Billing Demand of Demand Billed Customers	22,679	22,295	
Projected Design Day (Dth)	824,269	815,451	8,818

[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-2017 Budget	Jan-2016 Budget
Reserve Margin	45,854	23,929
Total Available Capacity	870,123	839,380
Entitlement per Customer	1.7080	1.6650

Northern States Power Company

DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER

Design Day: Heating Season 2016-2017

	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)
	[TRADE SECRET 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)
	TRADE SECRET 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-16-___
Attachment 1
Schedule 4

Customer Class	Jul-2015	Aug-2015	Sep-2015	Oct-2015	Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Total	Winter	Summer
Residential	719,819	613,316	665,375	1,024,522	1,796,302	4,182,411	5,874,775	6,054,764	5,011,099	3,012,793	1,707,876	968,480	31,631,531	22,919,350	8,712,181
Interdepartmental	27	13	28	73	480	862	1,319	1,655	1,399	888	660	328	7,732	5,715	2,017
Small Commercial Firm	167,683	110,868	92,067	116,512	227,219	548,296	872,963	960,030	769,596	436,694	245,627	127,464	4,675,018	3,378,104	1,296,914
Large Commercial Firm	276,344	281,510	324,815	476,037	816,697	1,670,571	2,234,608	2,452,352	2,072,355	1,248,967	828,366	461,649	13,144,273	9,246,584	3,897,689
Commercial Firm	444,054	392,391	416,910	592,622	1,044,396	2,219,729	3,108,890	3,414,037	2,843,351	1,686,549	1,074,653	589,442	17,827,023	12,630,403	5,196,620
Small Commercial Demand Billed	5,807	5,686	6,023	8,051	7,364	12,645	14,584	13,525	13,909	10,367	8,461	7,289	113,710	62,026	51,684
Large Commercial Demand Billed	165,361	142,133	149,461	156,429	181,549	249,959	313,769	325,633	302,705	241,764	185,945	158,285	2,572,991	1,373,615	1,199,376
Large Demand Billed - Generation	1,231	1,516	1,612	1,284	972	1,779	1,611	1,659	1,563	1,468	1,752	1,614	18,059	7,583	10,476
Commercial Demand Billed	172,398	149,334	157,096	165,765	189,884	264,383	329,963	340,817	318,177	253,598	196,158	167,187	2,704,759	1,443,224	1,261,535
Total Commercial Firm	616,452	541,725	574,005	758,386	1,234,280	2,484,112	3,438,852	3,754,854	3,161,529	1,940,148	1,270,811	756,629	20,531,783	14,073,627	6,458,156
Total Firm	1,336,271	1,155,041	1,239,380	1,782,909	3,030,582	6,666,523	9,313,627	9,809,618	8,172,628	4,952,941	2,978,686	1,725,109	52,163,314	36,992,978	15,170,337
Small Interruptible	76,308	68,213	68,326	87,566	142,869	292,082	363,469	360,657	344,663	211,540	150,723	90,190	2,256,607	1,503,740	752,867
Medium Interruptible	314,068	315,663	297,810	404,980	561,106	570,656	690,584	1,085,220	740,626	562,002	510,197	319,872	6,372,783	3,648,192	2,724,591
Large Interruptible	129,361	133,659	129,855	116,674	90,830	139,417	201,046	211,870	198,478	152,360	96,378	111,316	1,711,245	841,642	869,603
Med. & Lg. Interruptible - Generation	6,732	10,017	2,118	1,300	2,171	3,833	9,776	11,455	10,526	7,087	6,642	4,493	76,152	37,762	38,390
Total Interruptible	526,469	527,552	498,109	610,522	796,976	1,005,989	1,264,875	1,669,202	1,294,294	932,989	763,940	525,870	10,416,787	6,031,336	4,385,451
Total Firm and Interruptible	1,862,740	1,682,593	1,737,489	2,393,430	3,827,558	7,672,512	10,578,502	11,478,820	9,466,921	5,885,930	3,742,626	2,250,979	62,580,101	43,024,313	19,555,788
Firm Transportation	28,046	30,195	26,368	28,433	29,231	24,154	23,777	40,550	41,061	31,489	31,278	30,551	365,133	158,773	206,360
Interruptible Transportation	330,881	297,445	300,268	345,805	336,112	375,531	363,871	405,317	383,445	367,391	333,887	317,619	4,157,572	1,864,276	2,293,296
Negotiated Transporation	464,937	349,823	469,145	629,556	595,700	707,410	647,000	322,218	671,155	573,220	545,073	507,023	6,482,260	2,943,483	3,538,777
Interdepartmental Transport - Generation	1,751,241	1,359,670	1,556,161	828,748	1,087,150	1,820,270	1,453,750	1,126,701	1,837,648	1,571,315	1,324,444	1,475,775	17,192,873	7,325,519	9,867,354
Total Transportation	2,575,105	2,037,133	2,351,942	1,832,542	2,048,193	2,927,365	2,488,398	1,894,786	2,933,309	2,543,415	2,234,682	2,330,968	28,197,838	12,292,051	15,905,787
Total Customer Sales	4,437,845	3,719,726	4,089,430	4,225,973	5,875,751	10,599,877	13,066,900	13,373,606	12,400,230	8,429,345	5,977,308	4,581,947	90,777,939	55,316,364	35,461,574
Monthly Heating Degree Days	3	15	61	409	714	1,073	1,457	1,149	745	522	172	6	6,326	5,138	1,188

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Docket No. G002/M-16-____

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2016-2017 Heating Season

Attachment 1
Schedule 5

Firm Supplies (1)	Current Quantity Effective Nov-15 Dth/Day	Proposed Quantity Effective Nov-16 Dth/Day	Proposed Quantity Change Nov-16 Dth/Day
A. Upstream Supply			
	[TRADE SECRET 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			**TRADE SECRET ENDS]**
LP Peak Shaving	90,000	90,000	-
LNG Peak Shaving	156,000	156,000	-
TOTAL	866,180	870,123	3,943
C. Minnesota State Delivered Supply			
State of MN Allocators	87.99%	87.98%	
TOTAL	762,152	765,534	3,382

(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: 2016/2017	454,396	725,225	765,534	Unknown	Unknown	Unknown
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	762,152	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
2003/2004	401,633	603,468	643,315	561,250	80	1/29/2004
2002/2003	395,807	607,856	642,275	534,385	65	1/20/2003

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
TRADE SECRET DATA EXCISED

Docket No. G002/M-16-____
Attachment 2
Schedule 1

Northern States Power Company
COMPANY DEMAND PROFILE
2016-2017 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	Discount Pkg Renewal	11.97%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27	Discount Pkg Renewal	0.00%
112182	NNG TF12 BASE (Disc)	26,626	0	26,626	10 yrs - 10/31/27	Discount Pkg Renewal	3.06%
112182	NNG TF12 VARIABLE (Disc.)	67,901	0	67,901	10 yrs - 10/31/27	Discount Pkg Renewal	7.80%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27	Discount Pkg Renewal	7.17%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27	Discount Pkg Renewal	3.40%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 10/31/22	Discount Pkg Renewal	3.28%
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27	Discount Pkg Renewal	6.69%
112185	NNG TFX (Disc. 12-month)	26,221	0	26,221	10 yrs - 10/31/27	Growth election	3.01%
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/27	Discount Pkg Renewal	Summer Only
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/27	Discount Pkg Renewal	Summer Only
112186	NNG TFX (Max)	49,005	0	49,005	10 yrs - 10/31/27	Discount Pkg Renewal	5.63%
112186	NNG TFX 2 (Max)	7,950	0	7,950	10 yrs - 10/31/27	Discount Pkg Renewal	Summer Only
112186	NNG TFX 5 (Max)	27,253	0	27,253	10 yrs - 10/31/27	Discount Pkg Renewal	Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27	Discount Pkg Renewal	2.87%
122067	NNG TFX (Disc. Nov-Mar)	7,834	1,539	9,373	10 yrs - 10/31/27	Growth election/Disc Renewal	1.08%
122067	NNG TFX 7 (Disc)	7,834	1,539	9,373	10 yrs - 10/31/27	Growth election/Disc Renewal	Summer Only
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/27	Discount Pkg Renewal	1.02%
122068	NNG TFX 7 (Max)	8,875	0	8,875	10 yrs - 10/31/27	Discount Pkg Renewal	Summer Only
		[TRADE SECRET BEGINS					
	VGT to NNG Chisago (1)						
	VGT Pierz to NNG (2)						
	Capacity Release						**TRADE SECRET ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/18		3.33%
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/18		0.49%
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/19		1.15%
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	8.5 yrs - 10/31/17		1.79%
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/21	Contract Renewal	0.22%
AF0217	VGT FT-A 12 Mos.	72,213	0	72,213	8 yrs - 10/31/17		8.30%
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/19		1.72%
AF0241	VGT FT-A (Dec-Feb)	12,428	(12,428)	0	3 mos - 2/28/2016	Contract expired	0.00%
TBD	VGT FT-A (Dec-Feb)	0	16,371	16,371	5 mos - 3/31/2017	Capacity acquisition	1.88%
	WBI FT-1097	8,000	0	8,000	26.5 yrs - 10/31/19		0.92%
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/17		2.76%
	LP Peak Shaving	63,200	26,800	90,000			10.34%
	LNG Peak Shaving	156,000	0	156,000			17.93%
	Total Design Day Capacity	**839,380**		**870,123**			**100%**
	Heating Season Total	839,380		870,123			
	Non-Heating Season Total	437,617		439,156			
	Miscellaneous Entitlements with Reservation Fees						
	Additional Pipeline Entitlements						
	ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/18		
	ANR FTS-106211 (Summer) (1)	4,935	0	4,935	3 yrs - 03/31/18		
	ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/18		
	ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	9 yrs - 10/31/2019		
	GLT FT171836 (2)	3,509	0	3,509	5 yrs - 03/31/19		
	GLT FT171836 (2)	4,475	0	4,475	5 yrs - 03/31/19		
	GLT Backhaul FT18130 (2)	895	0	895	3 yrs. - 10/31/17	Contract extension	
	GLT Backhaul FT18129 (2)	9,248	0	9,248	3 yrs. - 03/31/18	Contract extension	
	NNG SMS (3)	30,650		30,650	15 yrs - 10/31/17		
	VGT OBA (3)	7,400		7,400	14 yrs - 10/31/16		
	Supply Entitlements (4)						
	[TRADE SECRET BEGINS						
						TRADE SECRET ENDS]	
	Storage Entitlements - Deliverability						
	ANR Pipeline Storage	15,344	(44)	15,300	3 yrs - 3/31/18	Fuel adjustment	
	ANR Storage	9,248	0	9,248	3 yrs - 3/31/18	Contract extension	
	FDD Service	140,230		140,230	4 yrs - 5/31/18		
	FDD Service	78,050		78,050	15 yrs - 5/31/27		
	Storage Entitlements - Capacity						
	ANR Pipeline Storage	951,328	(328)	951,000	3 yrs - 3/31/18	Fuel adjustment	
	ANR Storage	1,165,000	0	1,165,000	3 yrs - 3/31/18	Contract extension	
	FDD Service	8,085,000	0	8,085,000	4 yrs - 5/31/18		
	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.

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2016

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	839,380	30,743	870,123
Non-Heating Season	437,617	1,539	439,156
Heating Season Forecasted Design Day	815,451	8,818	824,269
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	23,929	21,925	45,854
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	2.9%	2.6%	5.6%
Total MN State Available Capacity:			
State of MN Allocation Factor	87.99%	-0.01%	87.98%
State of MN Heating Season Capacity	738,570	26,964	765,534
State of MN Design Day Demand	717,478	7,747	725,225
State of MN Heating Season Capacity Reserve/(Shortage)	21,093	19,216	40,309
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	2.9%	2.6%	5.6%

(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, 2016
$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July 2016	Estimated Nov. 2016 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	$2.8402	$2.8137	$3.1517	-42.74%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.9008	$0.8220	$0.8327	$0.8434	-6.37%	2.60%	1.28%	$0.0107
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.5213	$5.5055	$5.8542	-29.16%	6.03%	6.33%	$0.3487
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$480.10	$478.73	$509.05	-29.16%	6.03%	6.33%	$30.32
Average Annual Total Demand Cost of Gas	$78.33	$71.48	$72.41	$73.34				**$0.93**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.8402	$2.8137	$3.1517	-42.56%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.8984	$0.8254	$0.8361	$0.8390	-6.61%	1.65%	0.35%	$0.0029
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.8987	$4.8829	$5.2238	-31.43%	6.64%	6.98%	$0.3409
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,391.35	$1,386.87	$1,483.69	-31.43%	6.64%	6.98%	$96.82
Average Annual Total Demand Cost of Gas	$255.17	$234.43	$237.47	$238.30				**$0.82**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.8402	$2.8137	$3.1517	-42.56%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.8917	$0.8099	$0.8206	$0.8390	-5.91%	3.59%	2.24%	$0.0184
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.8816	$4.8658	$5.2222	-31.38%	6.98%	7.32%	$0.3564
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,140.04	$7,116.93	$7,638.21	-31.38%	6.98%	7.32%	$521.28
Average Annual Total Demand Cost of Gas	$1,304.24	$1,184.59	$1,200.24	$1,227.15				**$26.91**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July 2016	Estimated Nov. 2016 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	$2.8402	$2.8137	$3.1517	-42.62%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9635	$0.9635	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.8037	$3.7772	$4.1152	-36.26%	8.19%	8.95%	$0.3380
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$30,186.87	$29,976.56	$32,658.96	-36.26%	8.19%	8.95%	$2,682.40
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	$2.8402	$2.8137	$3.1517	-42.38%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4751	$0.4751	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$3.3153	$3.2888	$3.6268	-38.99%	9.40%	10.28%	$0.3380
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$214,531.78	$212,816.99	$234,688.71	-38.99%	9.40%	10.28%	$21,871.72
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	$2.8402	$2.8137	$3.1517	-42.70%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4346	$0.4346	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$3.2748	$3.2483	$3.5863	-39.58%	9.51%	10.41%	$0.3380
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$2,442,940.52	$2,423,172.07	$2,675,313.08	-39.58%	9.51%	10.41%	$252,141.01
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	$0.3380	12.01%	$0.0107	1.28%	$0.93	$30.32	6.33%
Small Commercial	$0.3380	12.01%	$0.0029	0.35%	$0.82	$96.82	6.98%
Large Commercial	$0.3380	12.01%	$0.0184	2.24%	$26.91	$521.28	7.32%
Small Interruptible	$0.3380	12.01%	$0.0000	NA	$0.00	$2,682.40	8.95%
Medium Interruptible	$0.3380	12.01%	$0.0000	NA	$0.00	$21,871.72	10.28%
Large Interruptible	$0.3380	12.01%	$0.0000	NA	$0.00	$252,141.01	10.41%

DERIVATION OF CURRENT PGA COSTS

Nov. 2016 - Projected Costs (Actual prices will be determined Nov.1, 2016)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$32,063,960	$23,637,053	
2.	x Minnesota Design Day Ratio (2016 Demand Entitlement Filing)	87.98%	87.98%	
3.	Annual System Demand Allocation to MN	$28,209,872	$20,795,879	
4.	MN State Design Day (2016 Demand Entitlement Filing)	725,225	725,225	
5.	- Small & Large Demand Billed Dth (2016 Demand Entitlement Filing)	22,679	22,679	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	702,546	702,546	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$27,327,702	$20,145,557	
8.	Demand Billed Cost Allocation (3 - 7)	$882,170	$650,322	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	563,905,325	420,909,345	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04846	$0.04786	$0.09632
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)			$0.09632
14.	Total Demand Rate -Commercial (10 + 12)			$0.09632

	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$882,170	$650,322	$1,532,492
16.	/ Annual Contract Billing Demand (2016 Demand Entitlement Filing)			2,721,480
17.	Monthly Commercial Demand Billed Demand Rate			$0.56311

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$26,932,366
19.	x MN Portion of Monthly Retail Sales	86.56%
20.	MN Portion of Monthly Commodity Costs	$23,312,656
21.	MN Budgeted Calendar Month Retail Therm Sales	73,969,112
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.31517

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.41149**
24.	Small & Large Commercial (14 +22)	**$0.41149**
25.	Small & Large Demand Billed - Demand (17)	**$0.56311**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.31517**

*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) Regarding benefits of the contracts.

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

SUMMARY OF COMPANY HEDGE TRANSACTIONS

2016-2017 Heating Season

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

Certificate of Service

I, Carl Cronin, 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, and
Xcel Energy Misc. Gas Service List

Dated this 1st day of August 2016

/s/
____
Carl Cronin
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.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	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
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 South Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_6-1429_1
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.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	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
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	No	OFF_SL_6-1429_1
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_9-1153_Official
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
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	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
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	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 500 Saint Paul, MN 551012198	Electronic Service	Yes	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_9-1153_Official
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper Service	Yes	OFF_SL_9-1153_Official
Matthew P	Loftus	matthew.p.loftus@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
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 W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1153_Official
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_9-1153_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	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 500 Saint Paul, MN 551012198	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
Sandra	Hofstetter	sHofstetter@mnchamber.com	MN Chamber of Commerce	7261 County Road H Fremont, WI 54940-9317	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
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
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	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
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
SaGonna	Thompson	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
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas