414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

August 3, 2015

—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-15-___

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) 330-7529 or paul.lehman@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

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

DOCKET NO. G002/M-15-____

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. 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 2015-2016 Heating Season Supply Plan effective November 1, 2015, 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, 2015.

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

- 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

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 — 5th Floor
Minneapolis, Minnesota 55401
(612) 215-4662

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on August 3, 2015. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2015 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, 2015, 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

Paul J Lehman
Manager, Regulatory Compliance and Filings
Xcel Energy
414 Nicollet Mall — 7th Floor
Minneapolis, Minnesota 55401
(612) 330-7529

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, 2015, and respectfully request Commission approval of the revised entitlements effective on November 1, 2015. 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 2014-2015 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 outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, and pipeline billing units from the 2014-2015 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. The attachment shows a summary of hedge transactions for the 2015-2016 heating season.

F. Classification and Billing of Demand Costs

In the Company's 2007 Contract Demand Entitlement filing[1] 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,[2] 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,[3] the Commission ordered:

[1] Docket No. G002/M-07-1395.
[2] Docket No. G002/AA-12-756, Order dated November 14, 2013.

Required 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.

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

Schedule	Title
1, page 1	Demand Profile
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

Schedule	Title
1	Summary of Hedge Transactions

[3] 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.

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 $311,780.88 or about one percent of the total Minnesota State demand costs, effective November 1, 2015. 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 — 5th Floor
Minneapolis, Minnesota 55401
Alison.C.Archer@xcelenergy.com

SaGonna Thompson
Records Analyst
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Minneapolis, Minnesota 55401
Regulatory.Records@xcelenergy.com

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2015-2016 Heating Season Supply Plan effective November 1, 2015, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2015 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 3, 2015

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

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

DOCKET NO. G002/M-15-____

PETITION

SUMMARY OF FILING

Please take notice that on August 3, 2015, 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 2015-2016 Heating Season Supply Plan effective November 1, 2015. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2015, 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 4,163 customers, from 446,281 forecast for the 2014-2015 heating season to 450,444 forecast for the 2015-2016 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 1,533 Dekatherms (Dth), from 715,945 to 717,478, using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**.

We also used 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 2014, 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 695,182 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 22,295 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 717,478 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.

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

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 2015-2016 heating season compared to the 2014-2015 heating season as filed in Docket No. G002/M-14-654. **Attachment 1, Schedule 2** details the demand cost component changes for the 2015-2016 heating season. The projected DD for the Company increased by 5,779 Dth/day for the 2015-2016 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 $355,000. This slight increase is largely attributable to added entitlements due to on-system growth.

a. Change in Northern Natural Gas (Northern) entitlement (effective November 1, 2015)

Four modifications were made to firm capacity entitlement levels on Northern in the past year. First, we have added 1,105 Dth/day of incremental capacity at St. Cloud, Minnesota to be effective November 1, 2015. Second, we added 1,208 Dth/day of incremental firm capacity for the Hugo Area in Minnesota. Third, we added 3,333 Dth/day of incremental capacity in the Lake Elmo area of Minnesota. All of this capacity was added to meet the growing demands of our firm customers and will become effective November 1, 2015.

Finally, we did not renew a contract for 5,629 Dth/day of capacity with Northern. This capacity will be replaced by a lower cost option on Viking Gas Transmission that is discussed below.

b. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2015)

NSP plans to acquire one additional Viking firm contract for December 2015 through February 2016. We plan to purchase 12,428 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. Of this total, approximately 2,000 Dth/day is incremental capacity over the typical seasonal purchase of about 10,000 Dth/day described in last year's filing in Docket No.

G002/M-14-654. 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 a few months in the winter, since it is not needed on a year-round basis. We save our customers roughly $350,000 per year by using this approach.

c. Change in Great Lakes Gas Transmission (Great Lakes) entitlement (effective November 1, 2015)

NSP renewed two Great Lakes firm capacity entitlement this year. The previous capacity of 9,248 Dth/day purchased last winter expired March 31, 2015 and has been renewed on a winter-only basis for a two-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. By renewing for a longer period, we were able to take advantage of lower rates, which resulted in cost savings of roughly $150,000 per year.

d. Change in ANR Storage entitlement (effective April 1, 2015)

We renewed our contract with ANR Storage for two-years until March 31, 2017 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, 2015)

NSP renewed our ANR Pipeline entitlements for three-years until March 31, 2018. The extensions of these contracts provide for continued service from ANR Pipeline storage fields and regional diversity of supply to meet our projected DD needs. In addition, small additions 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.

3. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 88.42 percent to 87.99 percent. While most of the firm capacity entitlement changes occurred at Minnesota delivery points, overall the North Dakota DD projection grew more than the Minnesota DD projection causing the North Dakota DD allocation factor to increase slightly. 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 an increase of $136,762. **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 slightly decrease our capacity reserve margin from 6.3 percent in November 2014 to 6.2 percent in November 2015, as described in **Attachment 2, Schedule 1, Page 2 of 2**. 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 plans 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 2015-2016 heating season DD reserve margin for Minnesota State is 44,674 Dth/day or 6.2 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

2015-2016 Heating Season

Service Region (1)	Projected Jan 2016 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	316,505	114	14,426	0.0284705	91	1.2506080	1.009	498,567	512,993	
BRAINERD	16,346	3	118	0.0182201	91	1.1735980	1.009	19,993	20,110	
MAINLINE	15,084	14	1,421	0.0301920	88	1.3493409	1.009	23,269	24,690	
MAINLINE-WELCOME	2,371	0	0	0.0157164	88	0.8697394	1.009	2,729	2,729	
WILLMAR	10,770	2	169	0.0187776	88	0.8637919	1.009	13,352	13,520	
PAYNESVILLE	41,865	28	2,476	0.0343446	94	1.1267987	1.009	70,344	72,819	
VGT-CHISAGO	2,025	0	0	0.0119183	91	1.3303155	1.009	2,279	2,279	
WATKINS	7,523	1	50	0.0153266	94	1.0916510	1.009	9,206	9,256	
TOMAH	15,404	15	1,906	0.0300556	88	0.5132970	1.009	22,529	24,435	
RED WING	7,590	5	568	0.0296225	88	1.2466612	1.009	11,498	12,066	
GRAND FORKS MN	2,961	1	38	0.0268978	98	0.3622211	1.009	4,529	4,566	
FARGO MN	11,998	3	1,125	0.0263231	98	0.2903121	1.009	16,889	18,015	
MN State	**450,444**	**186**	**22,295**					**695,183**	**717,478**	**87.99%**
GRAND FORKS ND	15,719	0	0	0.0157683	98	1.7414493	1.009	29,134	29,134	
FARGO ND	36,622	0	0	0.0156042	98	1.8402583	1.009	67,332	67,332	
WBI ND	1,149	0	0	0.0112111	98	1.0644104	1.009	1,506	1,506	
ND State	53,490	0	0					97,973	97,973	12.01%
TOTAL	**503,934**	**186**	**22,295**					**793,156**	**815,451**	**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 2010 to December 2014.
(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
2015-2016 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) 2016 Unacc. Volume	Load Variation	Day Base	Total	2015 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO														
Total Residential	294,701	0.0104331	91	1.1472866	0.9856	0.0090	2,618	279,792	11,122	**293,533**	287,515	6,017	42,917	**336,449**
Total Small Commercial	16,459	0.0360882	91	3.1891351	0.9721	0.0090	502	54,051	1,727	**56,280**	54,475	1,805	8,229	**64,509**
Total Large Commercial	5,346	0.1644273	91	25.1039292	0.9831	0.0090	760	79,984	4,414	**85,158**	85,689	(531)	12,451	**97,609**
Industrial	114	Contract Demand	-	-		-	-	-	-	**14,426**	10,400	4,026	-	**14,426**
	316,619	0.0284705		1.250607964			3,880	413,828	17,263	**449,397**	438,079	11,318	63,596	**512,993**
												2.6%		
BRAINERD														
Total Residential	15,053	0.0093360	91	0.8730071	0.9845	0.0090	119	12,789	432	**13,340**	12,429	911	1,950	**15,291**
Total Small Commercial	1,161	0.0222532	91	5.0568247	0.9527	0.0090	23	2,351	193	**2,567**	2,473	94	375	**2,943**
Total Large Commercial	131	0.1118673	91	42.5019337	0.9497	0.0090	14	1,338	184	**1,535**	1,375	160	224	**1,759**
Industrial	3	Contract Demand	-	-		-	-	-	-	**118**	0	118	-	**118**
	16,349	0.0182201		1.173598036			156	16,478	809	**17,560**	16,277	1,283	2,550	**20,110**
												7.9%		
MAINLINE														
Total Residential	13,624	0.0099645	88	1.1523656	0.9846	0.0090	112	11,947	516	**12,575**	12,288	287	1,839	**14,414**
Total Small Commercial	1,174	0.0288546	88	3.7077918	0.9079	0.0090	28	2,982	143	**3,153**	3,176	(23)	461	**3,614**
Total Large Commercial	286	0.1676931	88	33.0282308	0.9534	0.0090	41	4,221	311	**4,573**	4,837	(264)	669	**5,241**
Industrial	14	Contract Demand	-	-		-	-	-	-	**1,421**	2,478	(1,057)	-	**1,421**
	15,098	0.0301920		1.349340877			181	19,149	970	**21,722**	22,779	(1,057)	2,968	**24,690**
												-4.6%		
MAINLINE-WELCOME														
Total Residential	2,232	0.0096503	88	0.7440297	0.9755	0.0090	18	1,896	55	**1,968**	1,823	145	288	**2,256**
Total Small Commercial	126	0.0164582	88	2.2414616	0.5791	0.0090	2	182	9	**193**	186	7	28	**221**
Total Large Commercial	14	0.1433129	88	106.4347561	0.4658	0.0090	2	170	47	**220**	246	(27)	32	**252**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,371	0.0157164		0.869739446			21	2,248	111	**2,381**	2,256	125	348	**2,729**
												5.5%		
WILLMAR														
Total Residential	9,972	0.0095072	88	0.7483458	0.9855	0.0090	77	8,343	245	**8,666**	7,967	699	1,267	**9,933**
Total Small Commercial	712	0.0305512	88	2.4412713	0.9753	0.0090	18	1,914	57	**1,989**	2,022	(33)	291	**2,280**
Total Large Commercial	86	0.1238816	88	18.2853945	0.8321	0.0090	9	933	51	**993**	797	196	145	**1,139**
Industrial	2	Contract Demand	-	-		-	-	-	-	**169**	213	(44)	-	**169**
	10,772	0.0187776		0.863791865			104	11,190	354	**11,817**	10,999	818	1,703	**13,520**
												7.4%		
PAYNESVILLE														
Total Residential	37,130	0.0093762	94	0.8797272	0.9880	0.0090	304	32,725	1,074	**34,103**	32,833	1,270	4,986	**39,089**
Total Small Commercial	3,776	0.0345150	94	3.5904794	0.9761	0.0090	114	12,250	446	**12,810**	12,321	489	1,873	**14,683**
Total Large Commercial	960	0.1499990	94	25.0019830	0.9827	0.0090	129	13,539	790	**14,458**	13,982	476	2,114	**16,571**
Industrial	28	Contract Demand	-	-		-	-	-	-	**2,476**	3,339	(863)	-	**2,476**
	41,893	0.0343446		1.126798663			547	58,513	2,310	**63,847**	62,475	1,371	8,973	**72,819**
												2.2%		
VGT-CHISAGO														
Total Residential	1,923	0.0089700	91	1.1588771	0.9816	0.0090	15	1,570	73	**1,658**	2,505	(848)	242	**1,900**
Total Small Commercial	99	0.0306993	91	4.7563300	0.8368	0.0090	3	275	15	**293**	623	(330)	43	**336**
Total Large Commercial	4	0.1097053	91	(6.5281707)	0.8861	0.0090	0	37	(1)	**37**	64	(27)	5	**42**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,025	0.0119183		1.330315462			18	1,882	88	**1,988**	3,193	(1,205)	291	**2,279**
												-37.7%		
WATKINS														
Total Residential	7,245	0.0091275	94	1.0170076	0.9842	0.0090	58	6,216	242	**6,516**	5,984	533	953	**7,469**
Total Small Commercial	238	0.0389962	94	2.7330314	0.9171	0.0090	8	874	21	**903**	834	69	132	**1,035**
Total Large Commercial	40	0.1083312	94	154.3135187	0.3298	0.0090	5	405	202	**613**	656	(44)	90	**702**
Industrial	1	Contract Demand	-	-		-	-	-	-	**50**	252	(202)	-	**50**
	7,524	0.0153266		1.09165102			72	7,495	466	**8,082**	7,726	356	1,174	**9,256**
												4.6%		
TOMAH														
Total Residential	13,822	0.0097448	88	0.4304619	0.9806	0.0090	108	11,853	196	**12,157**	12,269	(112)	1,777	**13,935**
Total Small Commercial	1,286	0.0251072	88	1.2844612	0.9621	0.0090	26	2,841	54	**2,922**	3,028	(107)	427	**3,349**
Total Large Commercial	296	0.1676957	88	16.7679093	0.9736	0.0090	41	4,372	163	**4,577**	4,756	(179)	669	**5,246**
Industrial	15	Contract Demand	-	-		-	-	-	-	**1,906**	2,795	(889)	-	**1,906**
	15,419	0.0300556		0.51329701			175	19,066	413	**21,561**	22,848	(1,287)	2,874	**24,435**
												-5.6%		
RED WING														
Total Residential	6,842	0.0095532	88	0.9347753	0.9852	0.0090	54	5,752	210	**6,016**	5,933	83	880	**6,896**
Total Small Commercial	606	0.0281514	88	4.8080466	0.9626	0.0090	14	1,501	96	**1,611**	1,510	101	236	**1,847**
Total Large Commercial	142	0.1835287	88	17.7011206	0.9750	0.0090	21	2,300	83	**2,404**	2,432	(28)	351	**2,756**
Industrial	5	Contract Demand	-	-		-	-	-	-	**568**	807	(239)	-	**568**
	7,595	0.0296225		1.246661212			89	9,553	389	**10,599**	10,681	(82)	1,467	**12,066**
												-0.8%		
GRAND FORKS MN														
Total Residential	2,648	0.0091104	98	0.1883268	0.9704	0.0090	21	2,364	16	**2,402**	2,311	91	351	**2,753**
Total Small Commercial	268	0.0378224	98	1.9297152	0.9633	0.0090	9	994	17	**1,021**	967	53	149	**1,170**
Total Large Commercial	45	0.1142342	98	11.3670409	0.9714	0.0090	5	507	17	**529**	528	0	77	**606**
Industrial	1	Contract Demand	-	-		-	-	-	-	**38**	63	(26)	-	**38**
	2,962	0.0268978		0.36222107			35	3,865	50	**3,989**	3,870	119	578	**4,566**
												3.1%		
FARGO MN														
Total Residential	10,808	0.0081397	98	0.0510278	0.9737	0.0090	78	8,622	18	**8,717**	8,082	635	1,275	**9,992**
Total Small Commercial	991	0.0288268	98	2.7401156	0.9589	0.0090	26	2,799	89	**2,914**	2,758	155	426	**3,340**
Total Large Commercial	199	0.1512555	98	18.7654675	0.9585	0.0090	28	2,953	123	**3,104**	2,970	134	454	**3,557**
Industrial	3	Contract Demand	-	-		-	-	-	-	**1,125**	916	209	-	**1,125**
	12,001	0.0263231		0.290312074			131	14,373	230	**15,860**	14,726	1,134	2,154	**18,015**
												7.7%		
MN COMPANY														
Total Residential	**416,000**									**401,652**	**391,941**	**9,711**	**58,725**	**460,376**
Total Small Commercial	**26,895**									**86,655**	**84,374**	**2,281**	**12,670**	**99,325**
Total Large Commercial	**7,549**									**118,199**	**118,332**	**-133**	**17,282**	**135,481**
Contract Demand	**186**									**22,295**	**21,262**	**1,033**	**0**	**22,295**
	450,630									**628,802**	**615,910**	**12,892**	**88,676**	**717,478**
												2.1%		

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2015-2016 Heating Season

Division/Region (1)	Projected Firm Jan 2015 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) 2016 Unacc. Volume	Load Variation	Day Base	Total	2015 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND														
Total Residential	13,610	0.0088021	98	0.3986138	0.9827	0.0090	107	11,740	178	**12,026**	10,956	1,070	1,758	**13,784**
Total Small Commercial	2,109	0.0607275	98	10.4080145	0.9550	0.0090	119	12,550	722	**13,392**	12,091	1,301	1,958	**15,350**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	15,719	0.0157683		1.741449333			227	24,291	900	**25,418**	23,047	2,371	3,716	**29,134**
												10.3%		
FARGO ND														
Total Residential	31,034	0.0084654	98	0.4018393	0.9819	0.0090	235	25,746	410	**26,391**	23,718	2,674	3,859	**30,250**
Total Small Commercial	5,588	0.0552511	98	9.8287263	0.9669	0.0090	289	30,257	1,807	**32,352**	28,115	4,238	4,730	**37,082**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	36,622	0.0156042		1.840258254			524	56,003	2,217	**58,744**	51,832	6,912	8,589	**67,332**
												13.3%		
WBI ND														
Total Residential	991	0.0093529	98	0.1962506	0.9591	0.0090	8	908	6	**923**	778	145	135	**1,058**
Total Small Commercial	158	0.0228540	98	6.5038112	0.4338	0.0090	3	354	34	**391**	519	(128)	57	**449**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	1,149	0.0112111		1.064410408			12	1,262	40	**1,314**	1,298	17	192	**1,506**
												1.3%		
ND COMPANY														
Total Residential	**45,635**									**39,340**	**35,451**	**3,889**	**5,752**	**45,092**
Total Small Commercial	**7,855**									**46,135**	**40,725**	**5,411**	**6,745**	**52,881**
Total Large Commercial	**0**									**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**									**-**	**-**	**-**	**-**	**-**
	53,490									**85,476**	**76,176**	**9,299**	**12,497**	**97,973**
												12.2%		
Grand Total														
Total Residential	**461,635**									**440,992**	**427,392**	**13,600**	**64,476**	**505,468**
Total Small Commercial	**34,750**									**132,791**	**125,099**	**7,692**	**19,415**	**152,206**
Total Large Commercial	**7,549**									**118,199**	**118,332**	**(133)**	**17,282**	**135,481**
Contract Demand	**186**									**22,295**	**21,262**	**1,033**	**-**	**22,295**
	504,120									**714,278**	**692,086**	**22,191**	**101,173**	**815,451**
												3.2%		

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2016 FORECAST	2015 FORECAST	Difference	%Diff
METRO	316,505	313,267	3,238	1.0%
BRAINERD	16,346	15,753	593	3.8%
MAINLINE	15,084	15,204	(120)	-0.8%
MAINLINE-WELCOME	2,371	2,257	115	5.1%
WILLMAR	10,770	10,219	551	5.4%
PAYNESVILLE	41,865	41,496	369	0.9%
VGT-CHISAGO	2,025	3,195	(1,169)	-36.6%
WATKINS	7,523	7,217	306	4.2%
TOMAH	15,404	15,657	(253)	-1.6%
RED WING	7,590	7,569	22	0.3%
GRAND FORKS MN	2,961	2,943	18	0.6%
FARGO MN	11,998	11,504	494	4.3%
MN STATE	450,444	446,281	4,163	0.9%
GRAND FORKS ND	15,719	15,497	222	1.4%
FARGO ND	36,622	35,489	1,133	3.2%
WBI ND	1,149	1,081	68	6.3%
ND STATE	53,490	52,067	1,423	2.7%
TOTAL NSP MN	503,934	498,348	5,586	**1.1%**

2016 Customer Counts

	MN	ND	
Res	416,000	45,635	**461,635**
Sm Com	26,895	7,855	**34,750**
Lg Com	7,549	0	**7,549**
Ind	186	0	**186**
	450,630	53,490	**504,120**

2016 Design Day Use By Customer Class

	MN	ND	
Res	460,376	45,092	**505,468**
Sm Com	99,325	52,881	**152,206**
Lg Com	135,481	0	**135,481**
Ind	22,295	0	**22,295**
	717,478	97,973	**815,451**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2016 FORECAST	2015 FORECAST	Difference	%Diff
METRO	512,993	507,356	5,637	1.1%
BRAINERD	20,110	19,344	767	4.0%
MAINLINE	24,690	25,947	(1,256)	-4.8%
MAINLINE-WELCOME	2,729	2,588	140	5.4%
WILLMAR	13,520	12,667	853	6.7%
PAYNESVILLE	72,819	72,635	185	0.3%
VGT-CHISAGO	2,279	3,770	(1,491)	-39.6%
WATKINS	9,256	8,987	269	3.0%
TOMAH	24,435	24,222	213	0.9%
RED WING	12,066	12,575	(510)	-4.1%
GRAND FORKS MN	4,566	4,541	25	0.6%
FARGO MN	18,015	17,809	206	1.2%
NEW COMMUNITIES		3,504	-	
MN STATE	717,478	715,945	1,533	0.7%
GRAND FORKS ND	29,134	28,250	884	3.1%
FARGO ND	67,332	63,903	3,429	5.4%
WBI ND	1,506	1,572	(66)	-4.2%
ND STATE	97,973	93,726	4,247	4.5%
TOTAL NSP MN	815,451	809,671	5,779	0.7%

MN / ND Allocation Factors

2016 DD	2015 DD	
0.8799	0.8842	**MN State Allocation**
0.1201	0.1158	**ND State Allocation**

NNG SYSTEM	2016 FORECAST	2015 FORECAST	Difference	%Diff
METRO	512,993	507,356	5,637	1.1%
BRAINERD	20,110	19,344	767	4.0%
MAINLINE	24,690	25,947	(1,256)	-4.8%
MAINLINE-WELCOME	2,729	2,588	140	5.4%
WILLMAR	13,520	12,667	853	6.7%
PAYNESVILLE	72,819	72,635	185	0.3%
WATKINS	9,256	8,987	269	3.0%
TOMAH	24,435	24,222	213	0.9%
RED WING	12,066	12,575	(510)	-4.1%
NNG SUBTOTAL	692,619	686,321	6,298	0.9%

VGT SYSTEM				
VGT-CHISAGO	2,279	3,770	(1,491)	-39.6%
GRAND FORKS MN	4,566	4,541	25	0.6%
FARGO MN	18,015	17,809	206	1.2%
GRAND FORKS ND	29,134	28,250	884	3.1%
FARGO ND	67,332	63,903	3,429	5.4%
WBI ND	1,506	1,572	(66)	-4.2%
NEW COMMUNITIES		3,504	-	
VGT SUBTOTAL	122,833	123,350	(517)	-0.4%
VGT & NNG TOTAL	815,452	809,671	5,781	0.7%

Northern States Power Company Docket No. G002/M-15-____
DEMAND COST OF GAS IMPACT - NOVEMBER 2015
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]	1,105	$ 8.6272	5	$ 47,665.28
NNG TFX (Apr - Oct)[1]	1,105	$ 4.0000	7	$ 30,940.00
NNG TFX (Jan - Dec)[1]	1,208	$ 3.8000	7	$ 32,132.80
NNG TFX (Jan - Dec)[1]	1,208	$ 3.8000	5	$ 22,952.00
NNG TFX (Nov - Mar)[1]	3,333	$ 5.3736	5	$ 89,551.04
NNG TFX (Apr - Oct)[1]	3,333	$ 4.5000	7	$ 104,989.50
NNG TFX (Nov - Mar)[1]	(5,629)	$ 15.1530	5	$ (426,481.19)
VGT FT-A (Dec - Feb)[2]	12,428	$ 4.7507	3	$ 177,125.10
VGT FT-A (Jan - Dec)[2]	(72,213)	$ 4.4954	2	$ (649,252.64)
VGT FT-A (Jan - Dec)[2]	72,213	$ 5.3593	2	$ 774,022.26
VGT FT-A (Jan - Dec)[2]	(29,002)	$ 3.3978	2	$ (197,085.99)
VGT FT-A (Jan - Dec)[2]	29,002	$ 4.3706	2	$ 253,512.28
VGT FT-A (Nov - Mar)[2]	(4,239)	$ 3.3978	2	$ (28,806.55)
VGT FT-A (Nov - Mar)[2]	4,239	$ 4.3706	2	$ 37,053.95
VGT FT-A (Jan - Dec)[2]	(10,000)	$ 3.3978	2	$ (67,956.00)
VGT FT-A (Jan - Dec)[2]	10,000	$ 4.3706	2	$ 87,412.00
VGT FT-A (Jan - Dec)[2]	(15,600)	$ 4.4954	2	$ (140,256.48)
VGT FT-A (Jan - Dec)[2]	15,600	$ 5.3593	2	$ 167,210.16
VGT FT-A (Jan - Dec)[2]	(1,903)	$ 3.3978	2	$ (12,932.03)
VGT FT-A (Jan - Dec)[2]	1,903	$ 4.3706	2	$ 16,634.50
VGT FT-A (Jan - Dec)[2]	(15,000)	$ 4.4954	2	$ (134,862.00)
VGT FT-A (Jan - Dec)[2]	15,000	$ 5.3593	2	$ 160,779.00
ANR FTS (Nov - Mar)[3]	(9,248)	$ 14.6460	5	$ (677,231.04)
ANR FTS (Nov - Mar)[3]	9,248	$ 11.4420	5	$ 529,078.08
ANR FTS (Nov - Mar)[3]	(15,310)	$ 2.0400	5	$ (156,162.00)
ANR FTS (Nov - Mar)[3]	15,310	$ 1.7820	5	$ 136,412.10
ANR FSS (Jan - Dec)[4]	34	$ 1.7820	12	$ 727.06
ANR FTS (Jan - Dec)[5]	4,829	$ 0.0900	12	$ 5,215.32
ANR FTS (Jan - Dec)[5]	4,829	$ 0.1500	12	$ 8,692.20
ANR FTS (Nov - Mar)[5]	15,171	$ 0.0900	5	$ 6,826.95
ANR FTS (Nov - Mar)[5]	15,171	$ 0.1500	5	$ 11,378.25
ANR FTS (Apr - Oct)[5]	4,935	$ 0.0900	7	$ 3,109.05
ANR FTS (Apr - Oct)[5]	4,935	$ 0.1500	7	$ 5,181.75
Total				$ 217,574.72

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Total	-	$136,762.00
Total MN & ND Demand Cost Adjustment		**$354,336.72**
Minnesota Allocation Factor (MN/ND Allocated Demand)		87.99%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 311,780.88**

[1]NNG Sixth Revised Volume No. 1, Ninth Revised Sheet No. 51, Effective April 1, 2015
[2]VGT Volume No. 1, Part 5.0 Statement of Rates, Effective April 1, 2015
[3]ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[4]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 0.0.0, Effective September 30, 2010

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-15-____
Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2014 SUPPLEMENTAL FILED COSTS				**$30,819,929.19**	**$23,413,065.11**	**$54,232,994.30**				
2014 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total					$ -	$ -				
2014 ACTUAL COSTS				**$ 30,819,929.19**	**$ 23,413,065.11**	**$ 54,232,994.30**				
CHANGES FOR 2015 FILING										
Contract Demand Entitlement Changes										
NNG TFX (Nov - Mar)	1,105	$ 8.6272	5		$ 47,665.28	$ 47,665.28	$ 47,665.28			1
NNG TFX (Apr - Oct)	1,105	$ 4.0000	7	$ 30,940.00		$ 30,940.00	$ 30,940.00			1
NNG TFX (Apr - Oct)	1,208	$ 3.8000	7	$ 32,132.80		$ 32,132.80	$ 32,132.80			2
NNG TFX (Nov - Mar)	1,208	$ 3.8000	5		$ 22,952.00	$ 22,952.00				2
NNG TFX (Nov - Mar)	3,333	$ 5.3736	5		$ 89,551.04	$ 89,551.04	$ 89,551.04			3
NNG TFX (Apr - Oct)	3,333	$ 4.5000	7	$ 104,989.50		$ 104,989.50	$ 104,989.50			3
NNG TFX (Nov - Mar)	(5,629)	$15.1530	5		$ (426,481.19)	$ (426,481.19)	$ (426,481.19)			4
VGT FT-A (Dec - Feb)	12,428	$ 4.7507	3		$ 177,125.10	$ 177,125.10		$ 177,125.10		5
VGT FT-A (Jan - Dec)	(72,213)	$ 4.4954	2	$ (649,252.64)		$ (649,252.64)	$ (571,277.40)	$ (77,975.24)		6
VGT FT-A (Jan - Dec)	72,213	$ 5.3593	2	$ 774,022.26		$ 774,022.26	$ 681,062.19	$ 92,960.07		6
VGT FT-A (Jan - Dec)	(29,002)	$ 3.3978	2	$ (197,085.99)		$ (197,085.99)	$ (173,415.96)	$ (23,670.03)		6
VGT FT-A (Jan - Dec)	29,002	$ 4.3706	2	$ 253,512.28		$ 253,512.28	$ 223,065.46	$ 30,446.83		6
VGT FT-A (Nov - Mar)	(4,239)	$ 3.3978	2		$ (28,806.55)	$ (28,806.55)	$ (25,346.88)	$ (3,459.67)		6
VGT FT-A (Nov - Mar)	4,239	$ 4.3706	2		$ 37,053.95	$ 37,053.95	$ 32,603.77	$ 4,450.18		6
VGT FT-A (Jan - Dec)	(10,000)	$ 3.3978	2	$ (67,956.00)		$ (67,956.00)	$ (59,794.48)	$ (8,161.52)		6
VGT FT-A (Jan - Dec)	10,000	$ 4.3706	2	$ 87,412.00		$ 87,412.00	$ 76,913.82	$ 10,498.18		6
VGT FT-A (Jan - Dec)	(15,600)	$ 4.4954	2	$ (140,256.48)		$ (140,256.48)	$ (123,411.68)	$ (16,844.80)		6
VGT FT-A (Jan - Dec)	15,600	$ 5.3593	2	$ 167,210.16		$ 167,210.16	$ 147,128.22	$ 20,081.94		6
VGT FT-A (Jan - Dec)	(1,903)	$ 3.3978	2	$ (12,932.03)		$ (12,932.03)	$ (11,378.89)	$ (1,553.14)		6
VGT FT-A (Jan - Dec)	1,903	$ 4.3706	2	$ 16,634.50		$ 16,634.50	$ 14,636.70	$ 1,997.80		6
VGT FT-A (Jan - Dec)	(15,000)	$ 4.4954	2	$ (134,862.00)		$ (134,862.00)	$ (31,503.76)	$ (103,358.24)		6
VGT FT-A (Jan - Dec)	15,000	$ 5.3593	2	$ 160,779.00		$ 160,779.00	$ 37,557.97	$ 123,221.03		6
GLT FT (Nov - Mar)	(9,248)	$14.6460	5		$ (677,231.04)	$ (677,231.04)			$ (677,231.04)	7
GLT FT (Nov - Mar)	9,248	$11.4420	5		$ 529,078.08	$ 529,078.08			$ 529,078.08	7
ANR FTS (Jan - Dec)	4,829	$ 0.0900	12	$ 5,215.32		$ 5,215.32			$ 5,215.32	8
ANR FTS (Jan - Dec)	4,829	$ 0.1500	12	$ 8,692.20		$ 8,692.20			$ 8,692.20	8
ANR FTS (Nov - Mar)	15,171	$ 0.0900	5		$ 6,826.95	$ 6,826.95			$ 6,826.95	8
ANR FTS (Nov - Mar)	15,171	$ 0.1500	5		$ 11,378.25	$ 11,378.25			$ 11,378.25	8
ANR FTS (Apr - Oct)	4,935	$ 0.0900	7		$ 3,109.05	$ 3,109.05			$ 3,109.05	8
ANR FTS (Apr - Oct)	4,935	$ 0.1500	7		$ 5,181.75	$ 5,181.75			$ 5,181.75	8
ANR FSS (Jan - Dec)	(15,310)	$ 2.0400	5		$ (156,162.00)	$ (156,162.00)			$ (156,162.00)	9
ANR FSS (Jan - Dec)	15,310	$ 1.7820	5		$ 136,412.10	$ 136,412.10			$ 136,412.10	9
ANR FSS (Jan - Dec)	34	$ 1.7820	12		$ 727.06	$ 727.06			$ 727.06	10
Total				$ 439,194.89	$ (221,620.17)	$ 217,574.72	$ 95,636.51	$ 225,758.50	$ (126,772.28)	
Supplier Entitlement Changes										
[TRADE SECRET BEGINS										
										11
										11
										11
										11
									TRADE SECRET ENDS]	
Total				$ -	$ 136,762.00	$ 136,762.00	$ 136,762.00	$ -	$ -	
TOTAL OF 2015 CHANGES				**$ 439,194.89**	**$ (84,858.17)**	**$ 354,336.72**	**$ 232,398.51**	**$ 225,758.50**	**$ (126,772.28)**	
2015 COSTS				**$ 31,259,124.08**	**$ 23,328,206.94**	**$ 54,587,331.02**				
2015 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							51%	49%		12

Footnote
1. Incremental capacity added near St. Cloud, MN starting November 1, 2015.
2. Incremental capacity added at Huga Area, MN starting November 1, 2015.
3. Incremental capacity added at Lake Elmo Area, MN starting November 1, 2015.
4. Expired winter firm transport capacity, November 1, 2014 through March 31, 2015.
5. Renewed firm transport capacity serving Fargo, ND, December 1, 2015 through February 28, 2016.
6. Entiries to reflect rate changes on Viking effective January 1, 2015.
7. Rate decrease due to renewal to longer term contract.
8. Expected change to ANR DTCA charge per settlement agreement currently before FERC. Reverse of credit and new charge.
9. Entries to account for rate reduction on ANR Pipeline storage agreement effective April 1, 2015.
10. Volume additions on ANR transport and storage agreements. Upstream capacity serves demand in either MN or ND.
11. Expired peaking supply contract with demand charges in effect November 1, 2014 through March 31, 2015.
12. 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 2015-2016

DESIGN DAY CALCULATION

State of Minnesota	Jan-2016 Budget Customer	2016 MMBtu Design Day[1]	2015 MMBtu Design Day[1]	MMBtu Change
Residential	416,000	460,376	458,360	2,016
Commercial	34,444	234,806	232,277	2,529
Demand Billed	186	22,295	21,803	492
New Communities			3,504	
State of Minnesota Total	**450,630**	**717,478**	**715,945**	**1,533**
State of North Dakota Total	53,490	97,973	93,726	4,247
Total Xcel Energy - Gas Utility Operations	504,120	815,451	809,671	5,780

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

Minnesota Company	Jan-2016 Budget Customer	Jan-2015 Budget Customer	Change
Residential	461,635	456,606	5,029
Commercial	42,299	41,742	557
TOTAL	503,934	498,348	5,586
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	793,156	784,364	
Demand Billed Customers	186	128	
Contracted Billing Demand of Demand Billed Customers	22,295	21,803	
Demand of New Communities		3,504	
Projected Design Day (Dth)	815,451	809,671	5,781

[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-2016 Budget	Jan-2015 Budget
Reserve Margin	50,728	46,377
Total Available Capacity	866,180	856,048
Entitlement per Customer	1.7182	1.7173

Northern States Power Company
DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER
Design Day: Heating Season 2015-2016

	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

MINNESOTA STATE HISTORICAL SALES - SEASONAL USAGE
(Dth)

Customer Class	Jul-2014	Aug-2014	Sep-2014	Oct-2014	Nov-2014	Dec-2014	Jan-2015	Feb-2015	Mar-2015	Apr-2015	May-2015	Jun-2015	Total	Winter	Summer
Residential	746,596	638,317	736,043	1,394,826	2,491,529	5,918,501	6,819,677	5,599,036	6,618,622	3,158,803	1,508,350	1,045,812	36,676,111	27,447,365	9,228,746
Interdepartmental	36	24	11	19	83	2,087	1,659	1,537	1,709	963	482	332	8,942	7,075	1,867
Small Commercial Firm	173,572	152,672	170,967	277,393	532,814	1,273,911	1,551,740	1,328,515	1,539,439	733,670	362,591	253,989	8,351,272	6,226,419	2,124,853
Large Commercial Firm	271,215	239,549	272,845	459,664	809,898	1,805,737	2,099,812	1,784,488	2,123,088	1,067,064	591,694	366,686	11,891,739	8,623,022	3,268,717
Commercial Firm	444,822	392,245	443,824	737,075	1,342,794	3,081,734	3,653,212	3,114,540	3,664,236	1,801,696	954,767	621,007	20,251,953	14,856,517	5,395,437
Small Commercial Demand Billed	6,194	5,514	6,221	9,338	8,417	15,113	15,070	12,641	17,746	10,711	8,184	6,799	121,949	68,988	52,961
Large Commercial Demand Billed	156,507	148,508	147,989	158,487	196,814	310,215	335,849	322,376	346,029	247,555	204,616	169,541	2,744,484	1,511,282	1,233,202
Large Demand Billed - Generation	1,506	1,244	1,357	1,018	1,547	2,062	1,446	1,507	1,391	1,494	1,078	1,359	17,011	7,954	9,057
Commercial Demand Billed	164,208	155,265	155,567	168,843	206,778	327,390	352,365	336,524	365,167	259,761	213,877	177,699	2,883,444	1,588,224	1,295,220
Total Commercial Firm	609,030	547,510	599,391	905,919	1,549,573	3,409,124	4,005,577	3,451,064	4,029,403	2,061,457	1,168,644	798,706	23,135,397	16,444,740	6,690,656
Total Firm	1,355,626	1,185,827	1,335,434	2,300,745	4,041,101	9,327,624	10,825,253	9,050,101	10,648,026	5,220,259	2,676,994	1,844,518	59,811,508	43,892,105	15,919,402
Small Interruptible	72,207	62,867	77,494	109,713	170,730	425,218	411,099	352,636	447,222	273,007	154,287	98,446	2,654,923	1,806,904	848,019
Medium Interruptible	349,193	340,693	290,125	367,055	630,752	752,664	682,503	685,268	755,721	572,040	516,080	332,953	6,275,045	3,506,907	2,768,138
Large Interruptible	195,414	184,494	134,206	105,198	109,921	187,032	229,017	207,959	211,644	145,354	103,725	88,576	1,902,539	945,573	956,966
Med. & Lg. Interruptible - Generation	9,679	10,971	2,263	3,885	18,577	2,434	14,881	1,658	9,833	6,708	9,297	1,309	91,493	47,382	44,111
Total Interruptible	626,492	599,025	504,087	585,850	929,980	1,367,347	1,337,499	1,247,520	1,424,419	997,109	783,387	521,283	10,924,000	6,306,765	4,617,235
Total Firm and Interruptible	1,982,118	1,784,852	1,839,521	2,886,595	4,971,081	10,694,971	12,162,752	10,297,621	12,072,445	6,217,368	3,460,381	2,365,801	70,735,507	50,198,870	20,536,637
Firm Transportation	18,228	19,775	18,561	21,367	20,800	22,071	22,678	24,004	19,794	18,803	17,687	17,289	241,057	109,347	131,710
Interruptible Transportation	290,240	316,674	290,644	338,253	322,920	376,754	441,022	391,202	347,390	333,695	297,540	289,208	4,035,542	1,879,288	2,156,254
Negotiated Transporation	436,127	535,263	482,238	444,188	701,818	741,606	709,711	646,861	563,907	572,969	462,580	391,796	6,689,064	3,363,903	3,325,161
Interdepartmental Transport - Generation	375,715	803,666	332,630	1,314,172	542,789	1,052,107	709,209	779,963	1,792,038	1,181,196	503,654	1,199,266	10,586,404	4,876,106	5,710,298
Total Transportation	1,120,310	1,675,378	1,124,073	2,117,980	1,588,327	2,192,538	1,882,620	1,842,030	2,723,129	2,106,663	1,281,461	1,897,559	21,552,067	10,228,644	11,323,423
Total Customer Sales	3,102,428	3,460,230	2,963,594	5,004,575	6,559,408	12,887,509	14,045,372	12,139,651	14,795,573	8,324,031	4,741,842	4,263,360	92,287,574	60,427,514	31,860,061
Monthly Heating Degree Days	9	0	138	496	1,178	1,245	1,423	1,497	907	451	198	10	7,551	6,249	1,302

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2015-2016 Heating Season

Firm Supplies (1)	Current Quantity Effective Nov-14 Dth/Day	Proposed Quantity Effective Nov-15 Dth/Day	Proposed Quantity Change Nov-15 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	856,048	866,180	10,132	
C. Minnesota State Delivered Supply				
State of MN Allocators	88.42%	87.99%		
TOTAL	756,918	762,152	5,234	

(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

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: 2015/2016	450,630	717,478	762,152	Unknown	Unknown	Unknown
2014/2015	446,409	715,945	761,354	687,501	64	1/12/2015
2013/2014	441,573	706,935	756,918	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

Northern States Power Company
COMPANY DEMAND PROFILE
2015-2016 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 - 10/31/17		12.02%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/17		0.00%
112182	NNG TF12 BASE (Disc)	34,191	0	34,191	10 yrs - 10/31/17		3.95%
112182	NNG TF12 VARIABLE (Disc.)	60,336	0	60,336	10 yrs - 10/31/17		6.97%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/17		7.21%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/17		3.42%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	8 yrs - 10/31/17		3.29%
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/17		6.72%
112185	NNG TFX (Disc. 12-month)	21,680	4,541	26,221	10 yrs - 10/31/17	Growth election	3.03%
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/17		Summer Only
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/17		Summer Only
112186	NNG TFX (Max)	49,005	0	49,005	10 yrs - 10/31/17		5.66%
112186	NNG TFX 2 (Max)	7,950	0	7,950	10 yrs - 10/31/17		Summer Only
112186	NNG TFX 5 (Max)	27,253	0	27,253	10 yrs - 10/31/17		Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/17		2.89%
122067	NNG TFX (Disc. Nov-Mar)	6,729	1,105	7,834	10 yrs - 10/31/17	Growth election	0.90%
122067	NNG TFX 7 (Disc)	6,729	1,105	7,834	10 yrs - 10/31/17	Growth election	Summer Only
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/24		1.02%
122068	NNG TFX 7 (Max)	8,875	0	8,875	10 yrs - 10/31/24		Summer Only
128226	NNG TFX (Nov-Mar)	5,629	(5,629)	0	5 mos. -3/31/15	Not renewed	0.00%
		[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		3.35%
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		1.80%
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/16		0.22%
AF0217	VGT FT-A 12 Mos.	72,213	0	72,213	8 yrs - 10/31/17		8.34%
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/19		1.73%
TBD	VGT FT-A (Dec-Feb)	0	12,428	12,428	3 mos - 2/28/2015	Capacity acquisition	1.43%
	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		2.77%
	LP Peak Shaving	90,000	0	90,000			10.39%
	LNG Peak Shaving	156,000	0	156,000			18.01%
	Total Design Day Capacity	**856,048**		**866,180**			**100%**
	Heating Season Total	856,048		866,180			
	Non-Heating Season Total	431,971		437,617			
	Miscellaneous Entitlements with Reservation Fees						
	Additional Pipeline Entitlements						
	ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/18	Contract extension	
	ANR FTS-106211 (Summer) (1)	4,935	0	4,935	3 yrs - 03/31/18	Contract extension	
	ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/18	Contract extension	
	ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	9 yrs - 10/31/2019		
	GLT FT171836 (2)	3,509	0	3,509	3 yrs - 03/31/17		
	GLT FT171836 (2)	4,475	0	4,475	3 yrs - 03/31/17		
	GLT Backhaul FT18130 (2)	895	0	895	2 yrs. - 03/31/17		
	GLT Backhaul FT18129 (2)	9,248	0	9,248	2 yrs. - 03/31/17		
	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						
	ANR Pipeline Storage (.951 MMcf)	15,310	34	15,344	3 yrs - 3/31/18	Contract extension	
	ANR Storage (1.165 MMcf)	9,248	0	9,248	2 yrs - 3/31/17	Contract extension	
	FDD Service (8.085 MMcf)	140,230		140,230	4 yrs - 5/31/18		
	FDD Service (4.5 MMcf)	78,050		78,050	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, 2015

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	856,048	10,132	866,180
Non-Heating Season	431,971	5,646	437,617
Heating Season Forecasted Design Day	809,671	5,781	815,452
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	46,377	4,351	50,728
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	5.7%	0.5%	6.2%
Total MN State Available Capacity:			
State of MN Allocation Factor	88.42%	-0.43%	87.99%
State of MN Heating Season Capacity	756,918	5,234	762,152
State of MN Design Day Demand	715,945	1,533	717,478
State of MN Heating Season Capacity Reserve/(Shortage)	40,973	3,701	44,674
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	5.7%	0.5%	6.2%

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

Northern States Power Company
MINNESOTA STATE RATE IMPACT

Docket No. G002/M-15-____
Attachment 2
Schedule 2

Date to implement proposed changes: November 1, 2015
$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-13-663)	Last Month PGA: July 2015	Estimated Nov. 2015 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	$3.7332	$2.8994	$3.1754	-42.31%	-14.94%	9.52%	$0.2760
Demand Cost of Gas (1)	$0.9008	$0.9347	$0.8819	$0.8657	-3.90%	-7.38%	-1.84%	($0.0162)
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$6.5270	$5.6404	$5.9002	-28.60%	-9.60%	4.61%	$0.2598
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$567.55	$490.46	$513.05	-28.60%	-9.60%	4.61%	$22.59
Average Annual Total Demand Cost of Gas	$78.33	$81.28	$76.68	$75.28				**($1.41)**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$3.7332	$2.8994	$3.1754	-42.13%	-14.94%	9.52%	$0.2760
Demand Cost of Gas (1)	$0.8984	$0.9323	$0.8852	$0.8689	-3.28%	-6.80%	-1.84%	($0.0163)
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$5.8986	$5.0177	$5.2774	-30.73%	-10.53%	5.18%	$0.2597
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,675.35	$1,425.15	$1,498.91	-30.73%	-10.53%	5.18%	$73.76
Average Annual Total Demand Cost of Gas	$255.17	$264.80	$251.42	$246.79				**($4.63)**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$3.7332	$2.8994	$3.1754	-42.13%	-14.94%	9.52%	$0.2760
Demand Cost of Gas (1)	$0.8917	$0.9116	$0.8695	$0.8535	-4.28%	-6.37%	-1.84%	($0.0160)
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$5.8763	$5.0004	$5.2604	-30.88%	-10.48%	5.20%	$0.2600
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$8,594.92	$7,313.80	$7,694.08	-30.88%	-10.48%	5.20%	$380.29
Average Annual Total Demand Cost of Gas	$1,304.24	$1,333.34	$1,271.76	$1,248.36				**($23.40)**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-13-663)	Last Month PGA: July 2015	Estimated Nov. 2015 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	$3.7332	$2.8994	$3.1754	-42.19%	-14.94%	9.52%	$0.2760
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	$4.6967	$3.8629	$4.1389	-35.89%	-11.88%	7.14%	$0.2760
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$37,273.81	$30,656.69	$32,847.05	-35.89%	-11.88%	7.14%	$2,190.36
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	$3.7332	$2.8994	$3.1754	-41.94%	-14.94%	9.52%	$0.2760
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	$4.2083	$3.3745	$3.6505	-38.59%	-13.25%	8.18%	$0.2760
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$272,317.12	$218,362.57	$236,222.31	-38.59%	-13.25%	8.18%	$17,859.75
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	$3.7332	$2.8994	$3.1754	-42.27%	-14.94%	9.52%	$0.2760
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	$4.1678	$3.3340	$3.6100	-39.18%	-13.38%	8.28%	$0.2760
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$3,109,100.05	$2,487,102.50	$2,692,992.79	-39.18%	-13.38%	8.28%	$205,890.29
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	$0.2760	9.52%	($0.0162)	-1.84%	($1.41)	$22.59	4.61%
Small Commercial	$0.2760	9.52%	($0.0163)	-1.84%	($4.63)	$73.76	5.18%
Large Commercial	$0.2760	9.52%	($0.0160)	-1.84%	($23.40)	$380.29	5.20%
Small Interruptible	$0.2760	9.52%	$0.0000	NA	$0.00	$2,190.36	7.14%
Medium Interruptible	$0.2760	9.52%	$0.0000	NA	$0.00	$17,859.75	8.18%
Large Interruptible	$0.2760	9.52%	$0.0000	NA	$0.00	$205,890.29	8.28%

DERIVATION OF CURRENT PGA COSTS

Nov. 2015 - Projected Costs (Actual prices will be determined Nov.1, 2015)*

Demand Cost (Res, Sm & Lg Commercial Firm)		Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$31,259,124	$23,328,207	
2.	x Minnesota Design Day Ratio (2015 Demand Entitlement Filing)	87.99%	87.99%	
3.	Annual System Demand Allocation to MN	$27,504,903	$20,526,489	
4.	MN State Design Day (2015 Demand Entitlement Filing)	717,478	717,478	
5.	- Small & Large Demand Billed Dth (2015 Demand Entitlement Filing)	22,295	22,295	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	695,183	695,183	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$26,650,212	$19,888,646	
8.	Demand Billed Cost Allocation (3 - 7)	$854,691	$637,843	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	538,954,024	403,492,517	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04945	$0.04929	$0.09874
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)			$0.09874
14.	Total Demand Rate -Commercial (10 + 12)			$0.09874
Demand Cost (Demand Billed)				
15.	Cost Allocated to Demand Billed (8)	$854,691	$637,843	$1,492,534
16.	/ Annual Contract Billing Demand (2015 Demand Entitlement Filing)			2,675,400
17.	Monthly Commercial Demand Billed Demand Rate			$0.55787

Commodity Costs		Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$27,091,884
19.	x MN Portion of Monthly Retail Sales	86.83%
20.	MN Portion of Monthly Commodity Costs	$23,523,883
21.	MN Budgeted Calendar Month Retail Therm Sales	74,081,430
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.31754

Total Gas Cost per Therm		
23.	Residential (13 + 22)	**$0.41628**
24.	Small & Large Commercial (14 +22)	**$0.41628**
25.	Small & Large Demand Billed - Demand (17)	**$0.55787**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.31754**

*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.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
SUMMARY OF COMPANY HEDGE TRANSACTIONS
2015-2016 Heating Season

								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**

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

CERTIFICATE OF SERVICE

I, Jim Erickson, 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 3rd day of August 2015

/s/
____
Jim Erickson
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
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	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
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	150 S. 5th Street, #1200 Minneapolis, MN 55402	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
Michael	Greiveldinger	michaelgreiveldinger@alliantenergy.com	Interstate Power and Light Company	4902 N. Biltmore Lane Madison, WI 53718	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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.	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	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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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
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_9-1153_Official
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
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
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Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	150 S. 5th Street, #1200 Minneapolis, MN 55402	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, 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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	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
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	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
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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
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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
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
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

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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
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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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