Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

August 1, 2013

—Via Electronic Filing—

Burl W. Haar
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-13-___

Dear Dr. Haar:

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

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	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-13-____

PETITION

INTRODUCTION

Pursuant to Minn. Stat. § 216B.16, Subd. 7 and Minn. Rule 7825.2910, Subp. 2, 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. Xcel Energy requests approval to implement our 2013-2014 Heating Season Supply Plan effective November 1, 2013, for customers served with natural gas in the State of Minnesota.

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 also 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. Also, the Summary has 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

Aakash Chandarana
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall — 5th Floor
Minneapolis, Minnesota 55401
(612) 215-4663

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on August 1, 2013. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2013 usage. Pursuant to Minn. Stat. § 216B.16, Subd. 7, Minn. Rule 7825.2920, and our Purchased Gas Adjustment tariff (Minnesota Gas Rate Book sheet number 5-40, revision 2; sheet number 5-41, revision 7; and sheet number 5-42, revision 3) Xcel Energy will provisionally place the PGA changes into effect on November 1, 2013, 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, permits 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, 2013, and respectfully request Commission approval of the revised entitlements effective on November 1, 2013. 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 2012-2013 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 2012-2013 entitlement levels pending Commission approval in Docket No. G002/M-12-862.

Please note that we have changed the format and added additional information to Attachment 2, Schedule 2, Pages 1 though 3. We are using the format that the Department requested in informal information requests the past two years.

C. Change in Jurisdictional Allocations

The changes in the DD forecast alter the allocation of entitlements between the Minnesota and North Dakota retail natural gas jurisdictions. This filing reflects this reallocation.

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-08-46 (Order dated May 27, 2008) regarding our use of financial instruments to limit commodity price volatility. The attachment shows a summary of hedge transactions for the 2013-2014 heating season.

Our variance to use financial instruments to reduce the natural gas commodity price volatility for our retail gas customers expired on June 30, 2012.[1] We filed a petition to extend the variance on May 25, 2012.[2] The petition is pending Commission action.

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[1] Docket No. G002/M-08-46
[2] Docket No. G002/M-12-519

We have not entered into any contracts since June 30, 2012. None of the executed contracts entered into prior to June 30, 2012 extend into the 2013-2014 heating season.

F. Classification and Billing of Demand Costs

In the Company's 2007 Contract Demand Entitlement filing,[3] we included a proposal to assign some demand costs – storage capacity demand charges and pipeline balancing charges – to interruptible customers. In our 2011 Contract Demand Entitlement filing (2011 CD filing)[4], we provided an updated proposal with current costs and the current effect on prices by customer class. These filings have been recommended for approval by the Department and are pending Commission action.

In the 2012 natural gas Automatic Annual Adjustment filing[5] (2012 AAA), the Department recommended "for all regulated gas utilities, the Commission require that all balancing service costs be recovered in the commodity portion of the PGA." These are the pipeline balancing charges referred to above. In the 2012 AAA,[6] we supported the Department's proposal for two reasons. One, the effect to customers was analogous in that interruptible classes would pay for some costs that are currently only allocated to firm customers, but from which interruptible customers benefit. Two, the methodology the Department proposed was simpler from an accounting standpoint than the methodology we have proposed in our contract demand entitlement filings.

If the Commission decides to approve the Department's recommendation in the 2012 AAA to treat the pipeline balancing charges as commodity, we will file to update the methodology in our contract demand entitlement dockets to remove the pipeline balancing charges. We will continue to support the part of the proposal to assign the storage capacity demand charges to interruptible customers as last described in our 2011 CD filing.

If the Commission decides not to approve the Department's recommendation in 2012 AAA, we will continue to support the full proposal as last described in our 2011 CD filing to allocate a portion of the pipeline balancing charges and the storage capacity demand charges to interruptible customers. This portion is determined by allocating the costs to state and then to the interruptible classes by sales. Effects of this allocation are illustrated on **Attachment 2, Schedule 2**.

[3] Docket No. G002/M-07-1395
[4] Docket No. G002/M-11-1076
[5] Docket No. G002/AA-12-756, May 6, 2013 Response Comments
[6] Docket No. G002/AA-12-756, May 16, 2013 Reply to Response Comments.

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

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 **[TRADE SECRET BEGINS TRADE SECRET ENDS]** effective November 1, 2013. 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:

Aakash Chandarana
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall — 5th Floor
Minneapolis, Minnesota 55401

SaGonna Thompson
Records Analyst
Xcel Energy
414 Nicollet Mall — 7th Floor
Minneapolis, Minnesota 55401

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2013-2014 Heating Season Supply Plan effective November 1, 2013, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2013 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, 2013

Northern States Power Company

/s/

BY: ______________________

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
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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-13-____

SUMMARY

SUMMARY OF FILING

Please take notice that on August 1, 2013, 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 2013-2014 Heating Season Supply Plan effective November 1, 2013. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2013, 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:

- Decrease in Design Day (DD) requirements,
- Changes in Resources required to meet the DD and provide an adequate reserve margin,
- Changes in 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.

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

We project our forecasted firm customer count in Minnesota State to increase by 2,363 customers (from 439,210 to 441,573) between the 2012-2013 and the 2013-2014 heating season forecasts. This projection equates to an increase in DD requirements in Minnesota state of 4,776 Dekatherms (Dth) (from 702,159 to 706,935) using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**. This increase in firm requirements is attributable to customer growth relating to economic recovery.

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 2008 – December 2012, as shown on **Attachment 1, Schedule 1, Pages 2 - 4**. Almost 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 those with much lower customer counts. In all, R-squared values were, on average, 93 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 develops 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 685,673 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 21,262 Dth is added to the DD estimate for the Residential, Small Commercial, and Large Commercial classes to determine the total Minnesota state DD Projection of 706,935 Dth as shown on **Attachment 1, Schedule 3, Page 1 of 2**.

We continue to maintain and compare both methodologies. We compared the actual peak days experienced by the Company under non-DD conditions with both the UPC DD and the Avg. Monthly DD to ensure adequate firm resources are available to meet the varied demand requirements of our customers. If cold temperatures occur in the future, then the actual use per customer of 1.57393 Dth, as shown on **Attachment 1, Schedule 3**, **Page 2 of 2**, would be adjusted in future filings. Likewise, if cold temperatures are not experienced, the actual use per customer of

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

1.57393 Dth would be maintained (assuming no operating experience contrary to the conditions observed on January 29, 2004). In that case, the UPC DD would be adjusted in future filings for updated Residential, Small Commercial, and Large Commercial customer counts and any changes to the contracted Billing Demand for the Small and Large Demand Billed customers.

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 2013-2014 heating season compared to the 2012-2013 heating season as filed in Docket No. G002/M-12-862. **Attachment 1, Schedule 2** details the demand cost component changes for the 2013-2014 heating season.

Please note, we added Attachment 1, Schedule 2, Page 2 of 2 to address questions the Department had in G002/M-12-862. The schedule 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 roughly $126,000. Ignoring the offsetting upstream/system supply costs decreases, the schedule shows that Minnesota contributed about 96% of the stand alone cost increases for this year.

a. Change in Northern Natural Gas (Northern) entitlement (effective November 1, 2013)

Three modifications were made to entitlement levels on Northern in the past year. First, in April 2010 we added incremental capacity at Brainerd, MN effective November 1, 2011. Additional capacity was needed in Brainerd, MN to ensure adequate capacity to meet the demands of our firm customers and maintain a 5 percent reserve margin in the event of DD conditions. Beginning November 1, 2013, capacity at Brainerd will ratchet up to 4,839 Dth/day from 4,603 Dth/day. Additional capacity, which expires on October 31, 2024, will increase into service as follows:

November 1, 2014 - October 31, 2021	4,894 Dth/day
November 1, 2021 - October 31, 2022	535 Dth/day
November 1, 2022 - October 31, 2023	291 Dth/day
November 1, 2023 - October 31, 2024	55 Dth/day

Second, in April 2012 we added 2,078 Dth/day of incremental capacity in the Hugo, MN area as part of Northern's biennial growth election option. According to a historical peak day flow analysis, the Forest Lake #1A town-border-station (TBS) was short 1,821 Dth/day compared to the historical peak throughput which occurred January 1, 2007. The same analysis showed the Stacy #1 TBS was short 257 Dth/day compared to its historical peak day on January 15, 2009. Without increasing capacity at these locations, we potentially would be unable to meet our firm customer's requirements at design day temperatures (average daily temperature of -26 degrees). Therefore to ensure adequate capacity to meet the demands of our firm customers, we added capacity in the Hugo area.

Lastly, 1,498 Dth/day of incremental capacity was added at St. Cloud, MN as part of Northern's biennial growth election option. According to design day calculations conducted in March 2012, we were short capacity by 881 Dth/day on Northern's Paynesville lateral and 617 Dth/day short on Northern's Watkins lateral. Both laterals are west of the Minneapolis-St. Paul metropolitan area. Without increasing capacity on these laterals, we will outgrow the daily firm entitlement on Northern needed to meet our firm customer's requirements at design day temperatures.

b. Change in Great Lakes Gas Transmission (Great Lakes) entitlements (effective November 1, 2013)

In the 2012-2013 filing in Docket No. G002/M-12-862, we reported our intention of purchasing a backhaul agreement on Great Lakes for the November 1, 2012 through March 31, 2013 timeframe unless a supply displacement contract became a more economical option. As a result of further negotiations with suppliers, we purchased a displacement contract that expired March 31, 2013 in lieu of the projected backhaul agreement. After seeking bids from suppliers for the 2013-2014 heating season, we determined the market for displacement contracts had changed and that such a contract was no longer available at an economical cost. In July 2013, we contracted with Great Lakes for 6,706 Dth/day of backhaul capacity that will deliver storage withdrawals from ANR Storage in Michigan to Carlton, MN in support of NSPM customers served off Northern Natural Gas.

c. Change in Viking Gas Transmission (Viking) entitlement (effective December 1, 2013)

We plan to acquire backhaul capacity on Viking to transport volumes from Marshfield, the interconnect between Viking and ANR, to Fargo, ND. As was the case last year, we anticipate purchasing 14,287 Dth/day of capacity that will match backhaul capacity on Viking with upstream ANR capacity at Marshfield. It is expected that the term of this capacity will be December, 1, 2013 through February 28, 2014 because it will be used to meet design day requirements of firm customers served off Viking during the coldest winter days. In addition, we plan to purchase 5,713 Dth/day of forward haul capacity on Viking from Emerson, the interconnect with TransCanada at the Minnesota-Canadian border, terminating at Fargo, ND. This capacity is needed in order to meet firm customer's requirements at design day temperatures and maintain our reserve margin on Viking.

3. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota state jurisdiction from 89.07 percent to 88.95 percent. The Minnesota allocation factor decreased reflecting the recent demand growth in North Dakota. As in previous years, we calculate the allocation factor by dividing the DD forecasted demand for Minnesota state 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 existing supplier reservation charges is a decrease of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** annually. **Attachment 1, Schedule 2, Page 2 of 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 6.1 percent in November 2012 to 6.0 percent in November 2013, 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 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 2013-2014 heating season DD reserve margin for Minnesota state is 42,390 Dth/day or 6.0 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

2013-2014 Heating Season

Service Region (1)	Projected Jan 2013 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	309,872	71	10,400	0.0290203	91	1.2690214	1.009	493,146	503,546	
BRAINERD	15,581	0	0	0.0180531	91	1.2547829	1.009	18,769	18,769	
MAINLINE	15,040	11	2,478	0.0309149	88	1.3634932	1.009	23,409	25,887	
MAINLINE-WELCOME	2,232	0	0	0.0161026	88	0.9207317	1.009	2,601	2,601	
WILLMAR	10,107	2	213	0.0178224	88	0.8960874	1.009	12,438	12,650	
PAYNESVILLE	41,051	24	3,339	0.0341721	94	1.1684147	1.009	68,189	71,527	
VGT-CHISAGO	3,159	0	0	0.0128965	91	1.2110124	1.009	3,682	3,682	
WATKINS	7,138	1	252	0.0152620	94	1.1787805	1.009	8,618	8,870	
TOMAH	15,489	10	2,795	0.0307521	88	0.5116527	1.009	23,123	25,918	
RED WING	7,487	5	807	0.0297277	88	1.2141267	1.009	11,386	12,193	
GRAND FORKS MN	2,911	1	63	0.0271778	98	0.3861510	1.009	4,389	4,453	
FARGO MN	11,379	2	916	0.0269244	98	0.3203927	1.009	15,924	16,840	
MN State	**441,446**	**127**	**21,262**					**685,673**	**706,935**	**88.95%**
GRAND FORKS ND	14,882	0	0	0.0150999	98	1.6723996	1.009	26,575	26,575	
FARGO ND	34,086	0	0	0.0147789	98	1.7859858	1.009	59,766	59,766	
WBI ND	1,038	0	0	0.0124712	98	0.5019566	1.009	1,496	1,496	
ND State	50,006	0	0					87,837	87,837	11.05%
TOTAL	**491,452**	**127**	**21,262**					**773,510**	**794,772**	**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 2008 to December 2012
(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
2013-2014 Heating Season

Division/Region (1)	Projected Firm Jan 2013 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) 2014 Unacc. Volume	Load Variation	Day Base	Total	2013 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO														
Total Residential	288,387	0.0104339	91	1.1732774	0.9873	0.0090	2,565	273,821	11,130	**287,515**	288,587	(1,072)	44,011	**331,526**
Total Small Commercial	16,074	0.0357947	91	3.0813046	0.9741	0.0090	486	52,359	1,629	**54,475**	54,398	77	8,339	**62,813**
Total Large Commercial	5,410	0.1632822	91	25.5004873	0.9810	0.0090	764	80,387	4,538	**85,689**	85,346	344	13,117	**98,806**
Industrial	71	Contract Demand	-	-		-	-	-	-	**10,400**	11,175	(776)	-	**10,400**
	309,943	0.0290203		1.269021448			3,815	406,567	17,298	**438,079**	439,506	(1,427)	65,467	**503,546**
												-0.3%		
BRAINERD														
Total Residential	14,338	0.0090891	91	0.9739969	0.9877	0.0090	111	11,859	459	**12,429**	12,480	(51)	1,903	**14,332**
Total Small Commercial	1,117	0.0223616	91	4.8474965	0.9478	0.0090	22	2,273	178	**2,473**	2,531	(57)	379	**2,852**
Total Large Commercial	126	0.1028034	91	44.6479575	0.9352	0.0090	12	1,178	185	**1,375**	1,349	26	210	**1,585**
Industrial	-	Contract Demand	-	-		-	-	-	-	**0**	353	(353)	-	**0**
	15,581	0.0180531		1.254782917			145	15,310	822	**16,277**	16,713	(436)	2,492	**18,769**
												-2.6%		
MAINLINE														
Total Residential	13,565	0.0097597	88	1.1840828	0.9803	0.0090	110	11,650	528	**12,288**	12,289	(1)	1,881	**14,169**
Total Small Commercial	1,177	0.0290869	88	3.5068833	0.9340	0.0090	28	3,012	136	**3,176**	3,191	(15)	486	**3,662**
Total Large Commercial	299	0.1693950	88	35.0104090	0.9390	0.0090	43	4,450	344	**4,837**	4,855	(18)	740	**5,577**
Industrial	11	Contract Demand	-	-		-	-	-	-	**2,478**	2,438	41	-	**2,478**
	15,051	0.0309149		1.363493158			181	19,112	1,008	**22,779**	22,773	6	3,108	**25,887**
												0.0%		
MAINLINE-WELCOME														
Total Residential	2,102	0.0094623	88	0.8079839	0.9775	0.0090	16	1,751	56	**1,823**	1,824	(1)	279	**2,102**
Total Small Commercial	115	0.0174077	88	2.0971628	0.6650	0.0090	2	177	8	**186**	180	7	29	**215**
Total Large Commercial	14	0.1625431	88	100.1746082	0.5545	0.0090	2	198	46	**246**	245	2	38	**284**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,232	0.0161026		0.920731734			20	2,126	110	**2,256**	2,248	8	345	**2,601**
												0.3%		
WILLMAR														
Total Residential	9,347	0.0093050	88	0.7899897	0.9886	0.0090	71	7,653	243	**7,967**	7,992	(25)	1,220	**9,187**
Total Small Commercial	690	0.0321482	88	2.2967528	0.9537	0.0090	18	1,952	52	**2,022**	2,029	(7)	310	**2,332**
Total Large Commercial	71	0.1192536	88	19.6637798	0.8184	0.0090	7	744	46	**797**	798	(1)	122	**919**
Industrial	2	Contract Demand	-	-		-	-	-	-	**213**	113	100	-	**213**
	10,109	0.0178224		0.896087392			96	10,349	341	**10,999**	10,932	67	1,651	**12,650**
												0.6%		
PAYNESVILLE														
Total Residential	36,436	0.0091747	94	0.9323490	0.9892	0.0090	293	31,423	1,117	**32,833**	32,952	(118)	5,026	**37,859**
Total Small Commercial	3,671	0.0341390	94	3.5553253	0.9820	0.0090	110	11,782	429	**12,321**	12,255	66	1,886	**14,207**
Total Large Commercial	944	0.1474632	94	24.9314870	0.9811	0.0090	125	13,083	774	**13,982**	14,000	(18)	2,140	**16,122**
Industrial	24	Contract Demand	-	-		-	-	-	-	**3,339**	2,676	663	-	**3,339**
	41,075	0.0341721		1.168414679			527	56,288	2,321	**62,475**	61,882	593	9,052	**71,527**
												1.0%		
VGT-CHISAGO														
Total Residential	2,978	0.0087520	91	1.1354084	0.9850	0.0090	22	2,372	111	**2,505**	2,512	(6)	384	**2,889**
Total Small Commercial	173	0.0382502	91	2.5391953	0.9617	0.0090	6	603	14	**623**	614	9	95	**719**
Total Large Commercial	8	0.0893171	91	(3.2930819)	0.8618	0.0090	1	65	(1)	**64**	65	(0)	10	**74**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	3,159	0.0128965		1.211012365			28	3,040	125	**3,193**	3,190	3	489	**3,682**
												0.1%		
WATKINS														
Total Residential	6,862	0.0088126	94	1.0896638	0.9868	0.0090	53	5,684	246	**5,984**	5,991	(7)	916	**6,900**
Total Small Commercial	236	0.0361681	94	3.2829709	0.9272	0.0090	7	802	25	**834**	865	(30)	128	**962**
Total Large Commercial	40	0.1304378	94	123.7110983	0.4317	0.0090	6	488	162	**656**	638	19	100	**757**
Industrial	1	Contract Demand	-	-		-	-	-	-	**252**	252	-	-	**252**
	7,139	0.0152620		1.178780495			67	6,974	433	**7,726**	7,745	(19)	1,144	**8,870**
												-0.2%		
TOMAH														
Total Residential	13,881	0.0097941	88	0.4297988	0.9833	0.0090	109	11,964	196	**12,269**	12,328	(59)	1,878	**14,148**
Total Small Commercial	1,301	0.0257494	88	1.2608543	0.9580	0.0090	27	2,947	54	**3,028**	3,091	(63)	464	**3,492**
Total Large Commercial	307	0.1681187	88	16.9540885	0.9693	0.0090	42	4,542	171	**4,756**	4,793	(38)	728	**5,484**
Industrial	10	Contract Demand	-	-		-	-	-	-	**2,795**	1,685	1,110	-	**2,795**
	15,499	0.0307521		0.51165273			179	19,453	421	**22,848**	21,898	950	3,070	**25,918**
												4.3%		
RED WING														
Total Residential	6,767	0.0095251	88	0.9356856	0.9826	0.0090	53	5,672	208	**5,933**	5,935	(1)	908	**6,841**
Total Small Commercial	578	0.0277124	88	4.5017085	0.8894	0.0090	13	1,410	86	**1,510**	1,524	(14)	231	**1,741**
Total Large Commercial	142	0.1856108	88	19.2022795	0.9383	0.0090	22	2,320	90	**2,432**	2,484	(53)	372	**2,804**
Industrial	5	Contract Demand	-	-		-	-	-	-	**807**	807	-	-	**807**
	7,492	0.0297277		1.214126713			88	9,403	384	**10,681**	10,749	(68)	1,512	**12,193**
												-0.6%		
GRAND FORKS MN														
Total Residential	2,608	0.0088888	98	0.2155409	0.9793	0.0090	21	2,272	18	**2,311**	2,315	(5)	354	**2,665**
Total Small Commercial	257	0.0374075	98	1.9608226	0.9603	0.0090	9	942	17	**967**	969	(2)	148	**1,115**
Total Large Commercial	46	0.1113870	98	12.3656506	0.9528	0.0090	5	505	19	**528**	517	11	81	**609**
Industrial	1	Contract Demand	-	-		-	-	-	-	**63**	63	-	-	**63**
	2,912	0.0271778		0.386150996			34	3,719	54	**3,870**	3,865	5	583	**4,453**
												0.1%		
FARGO MN														
Total Residential	10,254	0.0079331	98	0.1141365	0.9763	0.0090	72	7,972	38	**8,082**	8,157	(75)	1,237	**9,319**
Total Small Commercial	928	0.0292422	98	2.4350242	0.9523	0.0090	25	2,660	74	**2,758**	2,779	(21)	422	**3,181**
Total Large Commercial	198	0.1455845	98	18.6058923	0.9680	0.0090	26	2,822	121	**2,970**	2,905	65	455	**3,424**
Industrial	2	Contract Demand	-	-		-	-	-	-	**916**	916	-	-	**916**
	11,381	0.0269244		0.32039274			123	13,453	234	**14,726**	14,757	(30)	2,114	**16,840**
												-0.2%		
MN COMPANY														
Total Residential	**407,524**									**391,941**	**393,363**	**-1,422**	**59,996**	**451,937**
Total Small Commercial	**26,318**									**84,374**	**84,425**	**-50**	**12,916**	**97,290**
Total Large Commercial	**7,604**									**118,332**	**117,993**	**339**	**18,114**	**136,446**
Contract Demand	**127**									**21,262**	**20,478**	**785**	**0**	**21,262**
	441,573									**615,910**	**616,259**	**-349**	**91,025**	**706,935**
												-0.1%		

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2013-2014 Heating Season

Division/Region (1)	Projected Firm Jan 2013 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) 2014 Unacc. Volume	Load Variation	Day Base	Total	2013 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND														
Total Residential	12,878	0.0084592	98	0.4297857	0.9859	0.0090	98	10,676	182	**10,956**	10,755	201	1,677	**12,633**
Total Small Commercial	2,004	0.0577739	98	9.6576727	0.9770	0.0090	108	11,346	637	**12,091**	12,011	80	1,851	**13,942**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	14,882	0.0150999		1.672399562			206	22,022	819	**23,047**	22,766	281 1.2%	3,528	**26,575**
FARGO ND														
Total Residential	28,916	0.0081558	98	0.4146419	0.9824	0.0090	212	23,112	394	**23,718**	23,294	424	3,631	**27,348**
Total Small Commercial	5,170	0.0518248	98	9.4565367	0.9854	0.0090	251	26,256	1,608	**28,115**	27,952	162	4,304	**32,418**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	34,086	0.0147789		1.785985835			462	49,367	2,003	**51,832**	51,246	586 1.1%	7,934	**59,766**
WBI ND														
Total Residential	891	0.0087270	98	0.3154530	0.9517	0.0090	7	762	9	**778**	762	16	119	**897**
Total Small Commercial	147	0.0351043	98	1.6293223	0.8735	0.0090	5	507	8	**519**	510	10	80	**599**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	1,038	0.0124712		0.501956556			12	1,269	17	**1,298**	1,272	25 2.0%	199	**1,496**
ND COMPANY														
Total Residential	**42,685**									**35,451**	**34,811**	**640**	**5,427**	**40,878**
Total Small Commercial	**7,321**									**40,725**	**40,473**	**252**	**6,234**	**46,959**
Total Large Commercial	**0**									**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**									**-**	**-**	**-**	**-**	**-**
	50,006									**76,176**	**75,284**	**892** **1.2%**	**11,661**	**87,837**
Grand Total														
Total Residential	**450,209**									**427,392**	**428,174**	**(782)**	**65,423**	**492,815**
Total Small Commercial	**33,639**									**125,099**	**124,898**	**202**	**19,149**	**144,249**
Total Large Commercial	**7,604**									**118,332**	**117,993**	**339**	**18,114**	**136,446**
Contract Demand	**127**									**21,262**	**20,478**	**785**	**-**	**21,262**
	491,579									**692,086**	**691,543**	**543** **0.1%**	**102,686**	**794,772**

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2014 FORECAST	2013 FORECAST	Difference	%Diff
METRO	309,872	308,225	1,647	0.5%
BRAINERD	15,581	15,497	83	0.5%
MAINLINE	15,040	14,958	82	0.5%
MAINLINE-WELCOME	2,232	2,220	12	0.5%
WILLMAR	10,107	10,054	54	0.5%
PAYNESVILLE	41,051	40,826	225	0.6%
VGT-CHISAGO	3,159	3,143	17	0.5%
WATKINS	7,138	7,101	37	0.5%
TOMAH	15,489	15,404	84	0.5%
RED WING	7,487	7,447	41	0.5%
GRAND FORKS MN	2,911	2,895	16	0.5%
FARGO MN	11,379	11,318	62	0.5%
MN STATE	441,446	439,087	2,359	0.5%
GRAND FORKS ND	14,882	14,506	377	2.6%
FARGO ND	34,086	33,232	853	2.6%
WBI ND	1,038	1,012	26	2.6%
ND STATE	50,006	48,750	1,256	2.6%
TOTAL NSP MN	491,452	487,837	3,615	**0.7%**

2014 Customer #s

	MN	ND	
Res	407,524	42,685	**450,209**
Sm Com	26,318	7,321	**33,639**
Lg Com	7,604	0	**7,604**
Ind	127	0	**127**
	441,573	50,006	**491,579**

2014 Design Day Use By Customer Class

	MN	ND	
Res	451,937	40,878	**492,815**
Sm Com	97,290	46,959	**144,249**
Lg Com	136,446	0	**136,446**
Ind	21,262	0	**21,262**
	706,935	87,837	**794,772**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2014 FORECAST	2013 FORECAST	Difference	%Diff
METRO	503,546	501,263	2,283	0.5%
BRAINERD	18,769	19,072	(303)	-1.6%
MAINLINE	25,887	25,705	182	0.7%
MAINLINE-WELCOME	2,601	2,572	29	1.1%
WILLMAR	12,650	12,492	158	1.3%
PAYNESVILLE	71,527	70,419	1,109	1.6%
VGT-CHISAGO	3,682	3,650	32	0.9%
WATKINS	8,870	8,826	45	0.5%
TOMAH	25,918	24,812	1,106	4.5%
RED WING	12,193	12,183	10	0.1%
GRAND FORKS MN	4,453	4,413	39	0.9%
FARGO MN	16,840	16,752	88	0.5%
MN STATE	706,935	702,159	4,776	0.7%
GRAND FORKS ND	26,575	26,048	527	2.0%
FARGO ND	59,766	58,635	1,131	1.9%
WBI ND	1,496	1,456	40	2.8%
ND STATE	87,837	86,139	1,698	2.0%
TOTAL NSP MN	794,772	788,298	6,474	0.8%

MN / ND Allocation Factors

2014 DD	2013 DD	
0.8895	0.8907	**MN State Allocation**
0.1105	0.1093	**ND State Allocation**

NNG SYSTEM	2014 FORECAST	2013 FORECAST	Difference	%Diff
METRO	503,546	501,263	2,283	0.5%
BRAINERD	18,769	19,072	(303)	-1.6%
MAINLINE	25,887	25,705	182	0.7%
MAINLINE-WELCOME	2,601	2,572	29	1.1%
WILLMAR	12,650	12,492	158	1.3%
PAYNESVILLE	71,527	70,419	1,109	1.6%
WATKINS	8,870	8,826	45	0.5%
TOMAH	25,918	24,812	1,106	4.5%
RED WING	12,193	12,183	10	0.1%
NNG SUBTOTAL	681,960	677,344	4,616	0.7%

VGT SYSTEM	2014 FORECAST	2013 FORECAST	Difference	%Diff
VGT-CHISAGO	3,682	3,650	32	0.9%
GRAND FORKS MN	4,453	4,413	39	0.9%
FARGO MN	16,840	16,752	88	0.5%
GRAND FORKS ND	26,575	26,048	527	2.0%
FARGO ND	59,766	58,635	1,131	1.9%
WBI ND	1,496	1,456	40	2.8%
VGT SUBTOTAL	112,812	110,954	1,857	1.7%
VGT & NNG Total	794,772	788,298	6,474	0.8%

Northern States Power Company — Docket No. G002/M-13-____

DEMAND COST OF GAS IMPACT - NOVEMBER 2013 — 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]	4,839	$ 15.1530	5	$ 366,626.84
NNG TFX (Nov - Mar)[1]	(4,603)	$ 15.1530	5	$ (348,746.30)
NNG TFX (Apr - Oct)[1]	4,839	$ 5.6830	7	$ 192,500.26
NNG TFX (Apr - Oct)[1]	(4,603)	$ 5.6830	7	$ (183,111.94)
NNG TFX (Jan - Dec)[1]	2,078	$ 3.8000	12	$ 94,756.80
NNG TFX (Nov - Mar)[1]	1,498	$ 8.6272	5	$ 64,617.73
NNG TFX (Apr - Oct)[1]	1,498	$ 4.0000	7	$ 41,944.00
VGT FT-A (Dec - Feb)[2]	14,287	$ 4.8871	3	$ 209,465.99
VGT FT-A (Dec - Feb)[2]	(14,287)	$ 4.8871	3	$ (209,465.99)
VGT FT-A (Dec - Feb)[2]	5,713	$ 3.7671	3	$ 64,564.33
GLGT FT (Nov - Mar)[3]	6,706	$ 9.4560	5	$ 317,059.68
ANR FTS (Jan - Dec)[4]	(4,895)	$ 4.1700	7	$ (142,885.05)
ANR FTS (Jan - Dec)[4]	4,855	$ 4.1600	7	$ 141,377.60
ANR FSS (Jan - Dec)[5]	17	$ 2.0400	12	$ 416.16
ANR FSS (Jan - Dec)[5]	88	$ 0.4000	12	$ 421.60
Total				$ 609,541.70

Supplier Entitlement Changes

Change in Supplier Reservation Fees

[TRADE SECRET BEGINS

Total MN & ND Demand Cost Adjustment

Minnesota Allocation Factor (MN/ND Allocated Demand)

MN only Demand Cost Adjustment due to MN/ND Allocated Demand

TRADE SECRET ENDS]

[1] NNG Sixth Revised Volume No. 1, Fifth Revised Sheet No. 51, Effective April 1, 2013

[2] VGT Volume No. 1, Part 5.0 - Statement of Rates, v. 12.0.0, Effective April 1, 2013

[3] GLGT Third Revised Volume No. 1, Part 4.1 - Statement of Rates, v. 2.0.0, Effective August 1, 2011
The GLGT contract for 15,266 Dth as reported in Docket. No. 12-0862 was never entered into.

[4] ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v. 0.0.0, Effective September 30, 2010

[5] ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 0.0.0, Effective September 30, 2010

[6] The Tenaska Exchange supply contract was effectuated instead of the GLGT contract for 15,266 Dth as reported in Docket No. G002/M-12-862.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-13-____
Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2012 FILED COSTS				$29,648,751.08	$27,470,718.55	$57,119,469.64				
2012 CHANGES FILED TO ACTUAL COSTS										
Contract Demand Entitlement Changes										
GLGT FT (Nov - Mar)	(15,266)	$ 3.6240	5		$ (276,619.92)	$ (276,619.92)	$ (276,619.92)			1
Supplier Entitlement Changes										
[TRADE SECRET BEGINS										
										2
									TRADE SECRET ENDS]	
2012 ACTUAL COSTS				$29,648,751.08	$27,253,756.93	$56,902,508.02	$ (216,961.62)			
CHANGES FOR 2013 FILING										
Contract Demand Entitlement Changes										
NNG TFX (Nov-Mar)	4,839	$ 15.1530	5		$ 366,626.84	$ 366,626.84	$ 366,626.84			3
NNG TFX (Nov-Mar)	(4,603)	$ 15.1530	5		$ (348,746.30)	$ (348,746.30)	$ (348,746.30)			3
NNG TFX (Apr-Oct)	4,839	$ 5.6830	7	$ 192,500.26		$ 192,500.26	$ 192,500.26			3
NNG TFX (Apr-Oct)	(4,603)	$ 5.6830	7	$ (183,111.94)		$ (183,111.94)	$ (183,111.94)			3
NNG TFX (Nov-Mar)	2,078	$ 3.8000	5		$ 39,482.00	$ 39,482.00	$ 39,482.00			4
NNG TFX (Apr-Oct)	2,078	$ 3.8000	7	$ 55,274.80		$ 55,274.80	$ 55,274.80			4
NNG TFX (Nov-Mar)	1,498	$ 8.6272	5		$ 64,617.73	$ 64,617.73	$ 64,617.73			5
NNG TFX (Apr-Oct)	1,498	$ 4.0000	7	$ 41,944.00		$ 41,944.00	$ 41,944.00			5
VGT FT-A (Dec-Feb)	(14,287)	$ 4.8871	3		$ (209,465.99)	$ (209,465.99)		$ (37,254.73)	$ (172,211.27)	6
VGT FT-A (Dec-Feb)	14,287	$ 4.8871	3		$ 209,465.99	$ 209,465.99		$ 24,897.84	$ 184,568.15	6
VGT FT-A (Dec-Feb)	5,713	$ 3.7671	3		$ 64,564.33	$ 64,564.33		$ 64,564.33		7
GLGT FT (Nov - Mar)	6,706	$ 9.4560	5		$ 317,059.68	$ 317,059.68	$ 317,059.68			8
ANR FTS (Apr - Oct)	4,895	$ 4.1700	7		$ (142,885.05)	$ (142,885.05)			$ (142,885.05)	9
ANR FTS (Apr - Oct)	4,855	$ 4.1600	7		$ 141,377.60	$ 141,377.60			$ 141,377.60	9
ANR FSS (Jan - Dec)	17	$ 2.0400	12		$ 416.16	$ 416.16			$ 416.16	9
ANR FSS (Jan - Dec)	88	$ 0.4000	12		$ 421.60	$ 421.60			$ 421.60	9
NNG Rate Changes				$ (28,916.16)	$ (20,654.40)	$ (49,570.56)	$ (49,570.56)			10
ANR Rate Changes				$ (579.48)	$ (758.55)	$ (1,338.03)			$ (1,338.03)	10
ANRS Rate Changes					$ (374,134.64)	$ (374,134.64)			$ (374,134.64)	10
WBI Rate Changes				$ (34,861.44)		$ (34,861.44)		$ (34,861.44)		10
Total				$ 42,250.04	$ 107,387.00	$ 149,637.03	$ 496,076.50	$ 17,346.00	$ (363,785.48)	
Supplier Entitlement Changes										
[TRADE SECRET BEGINS										
										11
									TRADE SECRET ENDS]	
Total				$ -	$ (23,658.30)	$ (23,658.30)	$ (23,658.30)	$ -	$ -	
TOTAL OF 2013 CHANGES				$ 42,250.04	$ 83,728.70	$ 125,978.73	$ 472,418.20	$ 17,346.00	$ (363,785.48)	
2013 COSTS				$29,691,001.12	$27,337,485.63	$57,028,486.75				
2013 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							96%	4%		12

Footnote

1. Great Lakes backhaul contract reported last year in Docket No. G002/M-12-862. Another contract was used in lieu of this proposed contract.
2. Tenaska exchange contract that was enetred into in place of the Great Lakes backhaul contract in footnote 1.
3. Firm transport capacity serving Brainerd, MN starting November 1, 2013.
4. Firm transport capacity serving Hugo, MN starting November 1, 2013.
5. Firm transport capacity serving St. Cloud, MN starting November 1, 2013.
6. Incremental capacity of 14,287 Dth/day on Viking expired February 28,2013. Will be renewed for December 1, 2013 through February 28, 2014.
   1,698 Dth/day or 12% of 14,287 Dth/day is allocated to ND, although this capacity may be used to serve any demand on the system.
   1,698 Dth/day is the increase in ND design day. (1,698 Dth/day * $4.8871 * 3 = $24,897.84).
7. Incremental transport capacity on Viking for December 1, 2013 through February 28, 2014.
8. Incremental backhaul transport capacity on Great Lakes for November 1, 2013 through March 28, 2014. Will be used for ANRS storage withdrawals.
9. Volume reductions on ANR transport and storage agreements. Upstream capacity serves demand in either MN or ND.
10. Miscellaneous demand rate changes on NNG, ANR, ANRS and WBI contracts. These rate changes did not impact transport capacity volumes.
11. New peaking supply contract with demand charges. Will be in effect December, 1, 2013 through February 28, 2014.
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.

DESIGN DAY CALCULATION

State of Minnesota	Jan-2014 Budget Customer	2014 MMBtu Design Day[1]	2013 MMBtu Design Day[1]	MMBtu Change
Residential	407,524	451,937	450,078	1,859
Commercial	33,922	233,736	231,603	2,133
Demand Billed	127	21,262	20,478	785
State of Minnesota Total	**441,573**	**706,935**	**702,159**	**4,776**
State of North Dakota Total	50,006	87,837	86,139	1,698
Total Xcel Energy - Gas Utility Operations	491,579	794,772	788,298	6,474

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

Minnesota Company	Jan-2014 Budget Customer	Jan-2013 Budget Customer	Change
Residential	450,209	446,993	3,216
Commercial	41,243	40,844	399
TOTAL	491,452	487,837	3,615
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	773,510	767,820	
Demand Billed Customers	127	123	
Contracted Billing Demand of Demand Billed Customers	21,262	20,478	
Projected Design Day (Dth)	794,772	788,298	6,475

[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-2014 Budget	Jan-2013 Budget
Reserve Margin	47,639	48,400
Total Available Capacity	842,411	836,698
Entitlement per Customer	1.7137	1.7147

Northern States Power Company

DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER

Design Day: Heating Season 2013-2014

	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-13-____
Attachment 1
Schedule 4

Customer Class	Jul-2012	Aug-2012	Sep-2012	Oct-2012	Nov-2012	Dec-2012	Jan-2013	Feb-2013	Mar-2013	Apr-2013	May-2013	Jun-2013	Total	Winter	Summer
Residential	662,766	654,141	628,531	1,416,615	2,641,163	3,945,633	6,909,726	5,842,808	5,726,171	4,654,852	2,567,446	1,047,626	36,697,478	25,065,501	11,631,977
Interdepartmental	32	5	28	93	705	1,186	1,707	1,911	1,603	1,354	933	369	9,927	7,113	2,815
Small Commercial Firm	145,434	142,913	146,939	268,701	496,498	864,473	1,417,424	1,366,458	1,180,204	1,020,435	579,411	232,884	7,861,774	5,325,058	2,536,716
Large Commercial Firm	235,552	248,073	254,194	468,981	817,717	1,318,147	2,005,513	1,894,368	1,721,220	1,503,760	894,876	387,331	11,749,732	7,756,965	3,992,767
Commercial Firm	381,018	390,990	401,161	737,775	1,314,921	2,183,806	3,424,645	3,262,737	2,903,028	2,525,549	1,475,220	620,584	19,621,433	13,089,136	6,532,297
Small Commercial Demand Billed	5,758	6,118	5,885	7,085	8,870	11,645	14,086	13,070	12,899	11,555	9,536	6,720	113,227	60,571	52,657
Large Commercial Demand Billed	123,832	127,927	146,933	144,298	207,214	238,864	319,469	330,872	290,131	286,983	207,049	163,969	2,587,541	1,386,549	1,200,992
Large Demand Billed - Generation	1,691	2,075	1,913	2,014	2,058	1,787	2,199	1,427	2,862	1,778	1,412	1,327	22,543	10,334	12,210
Commercial Demand Billed	131,281	136,121	154,731	153,397	218,142	252,296	335,754	345,370	305,892	300,316	217,996	172,016	2,723,312	1,457,454	1,265,858
Total Commercial Firm	512,298	527,111	555,892	891,172	1,533,062	2,436,102	3,760,399	3,608,107	3,208,920	2,825,865	1,693,216	792,600	22,344,745	14,546,589	7,798,155
Total Firm	1,175,064	1,181,252	1,184,423	2,307,787	4,174,226	6,381,735	10,670,125	9,450,914	8,935,090	7,480,717	4,260,662	1,840,226	59,042,223	39,612,090	19,430,133
Small Interruptible	71,731	68,471	67,617	117,196	226,600	330,607	481,477	417,474	446,332	363,046	254,039	103,835	2,948,425	1,902,490	1,045,935
Medium Interruptible	374,750	312,982	384,494	408,697	933,100	647,810	781,642	831,306	757,972	980,745	579,265	369,756	7,362,519	3,951,830	3,410,689
Large Interruptible	119,396	190,215	165,647	107,513	121,599	148,854	222,303	232,852	185,387	165,831	151,757	101,042	1,912,393	910,994	1,001,399
Med. & Lg. Interruptible - Generation	29,571	4,800	4,354	3,617	2,153	436	1,630	3,864	14,597	8,922	12,680	23,236	109,859	22,681	87,179
Total Interruptible	595,447	576,468	622,112	637,022	1,283,452	1,127,707	1,487,052	1,485,495	1,404,288	1,518,543	997,741	597,869	12,333,197	6,787,995	5,545,202
Total Firm and Interruptible	1,770,512	1,757,720	1,806,534	2,944,810	5,457,678	7,509,442	12,157,177	10,936,409	10,339,378	8,999,261	5,258,403	2,438,095	71,375,419	46,400,085	24,975,335
Firm Transportation	16,176	17,072	16,097	21,221	20,856	24,032	28,088	25,778	26,986	29,169	31,694	17,552	274,721	125,740	148,981
Interruptible Transportation	260,290	294,498	270,742	323,942	331,998	355,203	420,687	386,804	425,200	423,115	366,111	321,802	4,180,392	1,919,892	2,260,500
Negotiated Transporation	519,920	559,025	542,269	269,811	539,794	629,561	569,870	492,767	290,260	150,529	463,895	405,520	5,433,221	2,522,252	2,910,969
Interdepartmental Transport - Generation	3,598,177	1,459,587	312,470	399,998	797,295	1,334,849	1,673,199	1,315,639	1,841,149	2,217,496	361,618	714,077	16,025,554	6,962,131	9,063,423
Total Transportation	4,394,563	2,330,182	1,141,578	1,014,972	1,689,943	2,343,645	2,691,844	2,220,988	2,583,595	2,820,309	1,223,318	1,458,951	25,913,888	11,530,015	14,383,873
Total Customer Sales	6,165,074	4,087,902	2,948,113	3,959,781	7,147,621	9,853,087	14,849,021	13,157,397	12,922,973	11,819,569	6,481,722	3,897,046	97,289,307	57,930,100	39,359,208
Monthly Heating Degree Days	0	2	136	541	831	1,274	1,481	1,271	1,156	723	256	44	7,715	6,013	1,702

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Docket No. G002/M-13-____
Northern States Power Company — Attachment 1
FIRM SUPPLY ENTITLEMENTS — Schedule 5
2013-2014 Heating Season — Page 1 of 1

Firm Supplies (1)	**Current Quantity Effective 11/1/2012 Dth/Day**	**Proposed Quantity Effective 11/1/2013 Dth/Day**	**Proposed Quantity Change 11/1/2013 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	836,698	842,411	5,713	
C. Minnesota State Delivered Supply				
State of MN Allocators	89.07%	88.95%		
TOTAL	745,247	749,325	4,078	

(1) Contracts are available for inspection upon request
(2) ANR feeds VGT.
(3) GLGT feeds NNG or VGT
(3) The Current Quantity Effective 11/1/2012 column reported a Great Lakes capacity of 15,266 Dth/day in Docket No. G002/M-12-862. The contract was never entered into and the capacity is removed from the column in this year's filing.

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: 2013/2014	441,573	706,935	749,325	Unknown	Unknown	Unknown
2012/2013	439,210	702,159	745,247	661,134	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.

Northern States Power Company
COMPANY DEMAND PROFILE
2013-2014 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		12.36%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/17		0.00%
112182	NNG TF12 BASE (Disc)	11,937	0	11,937	10 yrs - 10/31/17		1.42%
112182	NNG TF12 VARIABLE (Disc.)	82,590	0	82,590	10 yrs - 10/31/17		9.80%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/17		7.41%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/17		3.51%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	8 yrs - 10/31/17		3.38%
112185	NNG TFX (Disc. Nov-Mar)	56,106	2,078	58,184	10 yrs - 10/31/17	Incremental capacity	6.91%
112185	NNG TFX (Disc. 12-month)	21,680	0	21,680	10 yrs - 10/31/17		2.57%
112185	NNG TFX 5 (Disc)	4,415	2,078	6,493	10 yrs - 10/31/17	Incremental capacity	Summer Only
112185	NNG TFX 2 (Disc)	90	2,078	2,168	10 yrs - 10/31/17	Incremental capacity	Summer Only
112186	NNG TFX (Max)	46,855	0	46,855	10 yrs - 10/31/17		5.56%
112186	NNG TFX 2 (Max)	5,800	0	5,800	10 yrs - 10/31/17		Summer Only
112186	NNG TFX 5 (Max)	25,103	0	25,103	10 yrs - 10/31/17		Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/17		2.97%
122067	NNG TFX (Disc. Nov-Mar)	4,800	1,498	6,298	10 yrs - 10/31/17	Growth election	0.75%
122067	NNG TFX 7 (Disc)	4,800	1,498	6,298	10 yrs - 10/31/17	Growth election	Summer Only
122068	NNG TFX (Nov-Mar)	4,603	236	4,839	10 yrs - 10/31/24	Incremental capacity	0.57%
122068	NNG TFX 7 (Max)	4,603	236	4,839	10 yrs - 10/31/24	Incremental capacity	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	Contract renewal	3.44%
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/18	Contract renewal	0.50%
AF0103	VGT FT-A (Apr-Oct)	5,000	0	5,000	15 yrs - 10/31/14		Summer Only
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	15 yrs - 10/31/14		1.19%
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	8.5 yrs - 10/31/17		1.85%
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/16		0.23%
AF0156	VGT FT-A 12 Mos.	72,213	0	72,213	8 yrs - 10/31/17		8.57%
TBD	VGT FT-A (Dec-Feb)	14,287	0	14,287	3 mos - 2/28/2014	Capacity acquisition	1.70%
TBD	VGT FT-A (Dec-Feb)	0	5,713	5,713	3 mos - 2/28/2014	Capacity acquisition	0.68%
	WBI FT-1097	8,000	0	8,000	26.5 yrs - 10/31/19		0.95%
	WBI FT-157	461	0	461	20 yrs - 07/01/33	Contract renewal	0.05%
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/17		2.85%
	LP Peak Shaving	90,000	0	90,000			10.68%
	LNG Peak Shaving	156,000	0	156,000			18.52%
	Total Design Day Capacity	**836,698**		**842,411**			**100%**
	Heating Season Total	836,698		842,411			
	Non-Heating Season Total	407,314		411,126			
	Miscellaneous Entitlements with Reservation Fees						
	Additional Pipeline Entitlements						
	ANR FTS-106209 12 Mos. (1)	4,829		4,829	7 yrs - 03/31/15		
	ANR FTS-106211 (Summer) (1)	4,895	(40)	4,855	7 yrs - 03/31/15	Capacity decrease w/ fuel filing	
	ANR FTS-106211 (Winter) (1)	15,171		15,171	7 yrs - 03/31/15		
	ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	9 yrs - 10/31/2019		
	GLT FT14739 (2)	3,509	0	3,509	4 yrs - 03/31/14		
	GLT FT14739 (2)	4,475	0	4,475	4 yrs - 03/31/14		
	GLT Backhaul (2)	0	6,706	6,706	5 mos. - 03/31/13	Capacity acquisition	
	NNG SMS (3)	30,650		30,650	15 yrs - 10/31/17		
	VGT OBA (3)	7,400		7,400	14 yrs - 10/31/09		
	Supply Entitlements (4)						
	[TRADE SECRET BEGINS						
						TRADE SECRET ENDS]	
	Storage Entitlements						
	ANR Pipeline Storage (.946 MMcf)	15,209	17	15,226	7 yrs - 3/31/15	Capacity increase w/ fuel filing	
	ANR Storage (.994 MMcf)	15,297		15,297	7 yrs - 3/31/14		
	FDD Service (8.085 MMcf)	140,230		140,230	5 yrs - 5/31/17 (1.4 MMcf expires 5/31/13)		
	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, 2013

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	836,698	5,713	842,411
Non-Heating Season	407,314	3,812	411,126
Heating Season Forecasted Design Day	788,298	6,474	794,772
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	48,400	(761)	47,639
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.1%	-0.1%	6.0%
Total MN State Available Capacity:			
State of MN Allocation Factor	89.07%	-0.12%	88.95%
State of MN Heating Season Capacity	745,247	4,078	749,325
State of MN Design Day Demand	702,159	4,776	706,935
State of MN Heating Season Capacity Reserve/(Shortage)	43,088	(698)	42,390
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.1%	-0.1%	6.0%

(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-13-____
Attachment 2
Schedule 2

Date to implement proposed changes: November 1, 2013

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Last Month PGA: July 2013	Estimated Nov 2013 PGAs with Proposed Demand Entitlement Changes	Estimated Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in G002/M-07-1395)	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	$7.0824	$3.8046	$3.7332	$3.7332	-32.18%	-47.29%	-1.88%	($0.0714)
Demand Cost of Gas (1)	$0.9008	$1.0716	$0.9350	$0.9347	$0.9218	3.76%	-12.78%	-0.03%	($0.0003)
Distribution Margin	$1.8591	$1.6263	$1.8591	$1.8591	$1.8591	0.00%	14.32%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$9.7803	$6.5987	$6.5270	$6.5141	-21.02%	-33.26%	-1.09%	($0.0717)
Average Annual Usage (Dk)	87	87	87	87	87				
Average Annual Total Cost	$718.60	$850.43	$573.78	$567.55	$566.43	-21.02%	-33.26%	-1.09%	($6.23)
Average Annual Total Demand Cost of Gas	$78.33	$93.18	$81.30	$81.28	$80.15			**Current Allocation**	**($0.03)**
								With Demand Costs moved to Interruptible	**($1.15)**
Small Commercial									
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$3.8046	$3.7332	$3.7332	-31.96%	-47.29%	-1.88%	($0.0714)
Demand Cost of Gas (1)	$0.8984	$1.0873	$0.9326	$0.9323	$0.9193	3.77%	-14.26%	-0.03%	($0.0003)
Distribution Margin	$1.2331	$1.1366	$1.2331	$1.2331	$1.2331	0.00%	8.49%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$9.3063	$5.9703	$5.8986	$5.8856	-22.58%	-36.62%	-1.20%	($0.0717)
Average Annual Usage (Dk)	284	284	284	284	284				
Average Annual Total Cost	$2,163.87	$2,643.22	$1,695.72	$1,675.35	$1,671.66	-22.58%	-36.62%	-1.20%	($20.36)
Average Annual Total Demand Cost of Gas	$255.17	$308.82	$264.88	$264.80	$261.10			**Current Allocation**	**($0.09)**
								With Demand Costs moved to Interruptible	**($3.78)**
Large Commercial									
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$3.8046	$3.7332	$3.7332	-31.96%	-47.29%	-1.88%	($0.0714)
Demand Cost of Gas (1)	$0.8917	$1.0569	$0.9259	$0.9255	$0.9128	3.79%	-12.43%	-0.04%	($0.0004)
Distribution Margin	$1.2315	$1.1324	$1.2315	$1.2315	$1.2315	0.00%	8.75%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$9.2717	$5.9620	$5.8902	$5.8775	-22.60%	-36.47%	-1.20%	($0.0718)
Average Annual Usage (Dk)	1,463	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$13,561.15	$8,720.27	$8,615.25	$8,596.68	-22.60%	-36.47%	-1.20%	($105.02)
Average Annual Total Demand Cost of Gas	$1,304.24	$1,545.86	$1,354.26	$1,353.67	$1,335.10			**Current Allocation**	**($0.59)**
								With Demand Costs moved to Interruptible	**($19.16)**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Last Month PGA: July 2013	Estimated Nov 2013 PGAs with Proposed Demand Entitlement Changes	Estimated Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in G002/M-07-1395)	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	$7.0824	$3.8046	$3.7332	$3.7332	-32.03%	-47.29%	-1.88%	($0.0714)
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0769	-	-	-	$0.0000
Distribution Margin	$0.9635	$0.8675	$0.9635	$0.9635	$0.9635	0.00%	11.07%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$7.9499	$4.7681	$4.6967	$4.6967	-27.25%	-40.92%	-1.50%	($0.0714)
Average Annual Usage (Dk)	7,936	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$63,091.22	$37,840.44	$37,273.81	$37,273.81	-27.25%	-40.92%	-1.50%	($566.64)
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$610.29			**Current Allocation**	**$0.00**
								With Demand Costs moved to Interruptible	**$610.29**
Medium Interruptible									
Commodity Cost of Gas (WACOG)	$5.4696	$7.0824	$3.8046	$3.7332	$3.7332	-31.75%	-47.29%	-1.88%	($0.0714)
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0629	-	-	-	$0.0000
Distribution Margin	$0.0475	$0.3900	$0.0475	$0.0475	$0.0475	0.00%	-87.82%	0.00%	$0.0000
Total per Dth Cost	$5.5171	$7.4724	$3.8521	$3.7807	$3.8436	-31.47%	-49.40%	-1.85%	($0.0714)
Average Annual Usage (Dk)	64,709	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$357,008.03	$483,533.20	$249,267.18	$244,646.94	$248,717.15	-31.47%	-49.40%	-1.85%	($4,620.24)
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$4,070.21			**Current Allocation**	**$0.00**
								With Demand Costs moved to Interruptible	**$4,070.21**
Large Interruptible									
Commodity Cost of Gas (WACOG)	$5.5006	$7.0824	$3.8046	$3.7332	$3.7332	-32.13%	-47.29%	-1.88%	($0.0714)
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0583	-	-	-	$0.0000
Distribution Margin	$0.4346	$0.3565	$0.4346	$0.4346	$0.4346	0.00%	21.91%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$7.4389	$4.2392	$4.1678	$4.2261	-29.78%	-43.97%	-1.68%	($0.0714)
Average Annual Usage (Dk)	862,845	862,845	862,845	862,845	862,845				
Average Annual Total Cost	$5,121,167.08	$6,418,618.68	$3,657,781.73	$3,596,174.58	$3,646,478.46	-29.78%	-43.97%	-1.68%	($61,607.14)
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$50,303.87			**Current Allocation**	**$0.00**
								With Demand Costs moved to Interruptible	**$50,303.87**

(1) Includes demand smoothing

Current Allocation Summary Change from most recent PGA Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	($0.0714)	-1.88%	($0.0003)	-0.03%	($0.03)	($6.23)	-1.09%
Small Commercial	($0.0714)	-1.88%	($0.0003)	-0.03%	($0.09)	($20.36)	-1.20%
Large Commercial	($0.0714)	-1.88%	($0.0004)	-0.04%	($0.59)	($105.02)	-1.20%
Small Interruptible	($0.0714)	-1.88%	$0.0000	NA	$0.00	($566.64)	-1.50%
Medium Interruptible	($0.0714)	-1.88%	$0.0000	NA	$0.00	($4,620.24)	-1.85%
Large Interruptible	($0.0714)	-1.88%	$0.0000	NA	$0.00	($61,607.14)	-1.68%

Demand Costs to Non-Firm Summary Change from most recent PGA Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	($0.0714)	-1.88%	($0.0132)	-1.41%	($1.15)	($7.36)	-1.28%
Small Commercial	($0.0714)	-1.88%	($0.0133)	-1.43%	($3.78)	($24.06)	-1.42%
Large Commercial	($0.0714)	-1.88%	($0.0131)	-1.43%	($19.16)	($123.59)	-1.42%
Small Interruptible	($0.0714)	-1.88%	$0.0769	NA	$610.29	$43.65	-1.50%
Medium Interruptible	($0.0714)	-1.88%	$0.0629	NA	$4,070.21	($550.03)	-0.22%
Large Interruptible	($0.0714)	-1.88%	$0.0583	NA	$50,303.87	($11,303.27)	-0.31%

DERIVATION OF CURRENT PGA COSTS

November 2013 - Projected Costs (Actual prices will be determined Nov. 1, 2013)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$29,691,001	$27,337,486	
2.	x Minnesota Design Day Ratio (2013 Demand Entitlement Filing)	88.95%	88.95%	
3.	Annual System Demand Allocation to MN	$26,410,145	$24,316,693	
4.	MN State Design Day (2013 Demand Entitlement Filing)	706,935	706,935	
5.	- Small & Large Demand Billed Dth (2013 Demand Entitlement Filing)	21,262	21,262	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	685,673	685,673	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$25,615,808	$23,585,320	
8.	Demand Billed Cost Allocation (3 - 7)	$794,337	$731,373	
9.	MN Annual / Seasonal Firm Therm Sales (2010 Rate Case)	527,615,567	403,181,815	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04855	$0.05850	$0.10705
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)			$0.10705
14.	Total Demand Rate - Commercial (10 + 12)			$0.10705
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$794,337	$731,373	$1,525,710
16.	/ Annual Contract Billing Demand (2013 Demand Entitlement Filing)			2,551,496
17.	Monthly Commercial Demand Billed Demand Rate			$0.59797

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$30,859,974
19.	x MN Portion of Monthly Retail Sales	87.25%
20.	MN Portion of Monthly Commodity Costs	$26,925,327
21.	MN Budgeted Calendar Month Retail Therm Sales	72,124,669
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.37332

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.48037**
24.	Small & Large Commercial (14 +22)	**$0.48037**
25.	Small & Large Demand Billed - Demand (17)	**$0.59797**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.37332**

*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.

Northern States Power Company
SUMMARY OF COMPANY HEDGE TRANSACTIONS
2013-2014 Heating Season

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

NO CONTRACTS HAVE BEEN ENTERED INTO FOR THE 2013-2014 HEATING SEASON

CERTIFICATE OF SERVICE

I, SaGonna Thompson, 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 2013

/s/

____

SaGonna Thompson
Records Analyst

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
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	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	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	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
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_6-1429_1
Lloyd	Grooms	lgrooms@winthrop.com	Winthrop and Weinstine	Suite 3500 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	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
Paula N.	Johnson		Interstate Power and Light Company	200 First Street SE PO Box 351 Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_6-1429_1
Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street 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	Paper 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
Joseph V.	Plumbo		Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Paper Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_9-1153_Official
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
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
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_9-1153_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Paper 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	Paper 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
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_9-1153_Official
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_9-1153_Official
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	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	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Nancy	Kelly	nancyk@eurekarecycling.org	Eureka Recycling	2828 Kennedy Street NE Minneapolis, MN 55413	Paper 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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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	Paper Service	No	OFF_SL_9-1153_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 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	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 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
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

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
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