division of energy resources
Minnesota Department of Commerce

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September 14, 2012

**PUBLIC DOCUMENT –
TRADE SECRET DATA HAS BEEN EXCISED**

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 7th Place East
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-12-862

Dear Dr. Haar:

Attached are the PUBLIC *Comments* of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Petition of Northern States Power Company for Approval of Changes in Contract Demand Entitlements.

The petition was filed on August 1, 2012. The petitioner on behalf of Xcel is:

Paul J. Lehman
Manager, Regulatory Compliance and Filings
Xcel Energy
414 Nicollet Mall - 7th Floor
Minneapolis, MN 55401

The Department recommends that the Commission approve Xcel's demand entitlements and its proposal to recover costs associated with demand entitlements, pending review of information discussed herein and resolution of any revisions in the implementation of changes in recovery of demand costs. The Department has requested further information from Xcel in reply comments and on implementation.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ MARLON GRIFFING
Financial Analyst
651-297-3900

MG/sm
Attachment

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G002/M-12-862

I. SUMMARY OF XCEL ENERGY'S REQUEST

Northern States Power Company (Xcel or the Company) filed a demand-entitlement petition (Petition) on August 1, 2012, with the Minnesota Public Utilities Commission (Commission). The Company requests Commission approval to place the Purchased Gas Adjustment (PGA) changes into effect on November 1, 2012. The Company has stated that, in the event that the Commission does not act by November 1, 2012, the Company, pursuant to Minnesota Statute § 216B.16, Subd. 7, Minnesota Rule 7825.2920, and Xcel's PGA tariff (Minnesota Gas Rate Book sheet number 5-40, revision 2; sheet number 5-41, revision 7; and sheet number 5-42, revision 3), will provisionally place the PGA changes into effect on November 1, 2012, subject to later Commission approval.

In its Petition, Xcel requested approval from the Commission to implement its proposed interstate pipeline transportation, storage entitlements, and other demand-related contracts for 2012-2013 effective November 1, 2012. The Company requested that the adjustments be made through the PGA to reflect changes in its firm pipeline demand entitlement levels[1] as follows:

- decrease its Minnesota jurisdictional Design Day capacity by 135 dekatherms (Dth), about 0.02 percent (135 Dth/702,294 Dth);
- change the capacity resources used to meet the Design Day requirement and increase the amount of capacity resources for Minnesota by 153 Dth or 0.02 percent (153 Dth/745,094 Dth);

[1] The entitlement levels discussed in Xcel Energy's filing for the total Minnesota Company are the combined entitlements for Xcel Energy's Minnesota and North Dakota jurisdictions. Minnesota's portion of the entitlements is the total combined entitlements times the Minnesota allocation factor discussed below. The Department has included Department Attachment 1, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

- with these minor changes in Minnesota's need and resources, essentially maintain its reserve margin for Minnesota at 6.1 percent;
- slightly decease the Jurisdictional Allocations to Minnesota (rather than North Dakota) to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

Specifically, Xcel requested the following changes in demand volumes for the total Minnesota Company as shown in Table 1.

Table 1: Proposed Changes in Entitlement for Minnesota Company

Type of Entitlement	Proposed Dth Change	Rate	Months	Proposed Cost Change
NNG TFX (Nov - Mar)	4,603	$15.1530	5	$348,746.30
NNG TFX (Nov - Mar)	(4,359)	$15.1530	5	($330,259.64)
NNG TFX (Apr - Oct)	4,603	$5.6830	7	$183,111.94
NNG TFX (Apr - Oct)	(4,359)	$5.6830	7	($173,405.38)
VGT FTA (Nov - Mar)	14,287	$4.8871	3	$209,465.99
GLGT FT (Nov - Apr)	15,266	$3.6240	5	$276,619.92
ANR FTS (Jan - Dec)	9,000	$5.3660	12	$579,528.00
ANR FTS (Jan - Dec)	(19)	$4.1700	12	($950.76)
ANR FSS (Jan - Dec)	(87)	$2.0400	12	($2,129.76)
ANR FSS (Jan - Dec)	(450)	$0.4000	12	($2,157.60)
Total for Change in Pipeline Entitlement				$1,088,569.02

As indicated in the table above, Xcel proposed a number of changes in its demand entitlements that would increase costs from all source systems by approximately $1.089 million. This amount is for Minnesota and North Dakota customers. As discussed further below, the majority of the increase in resources is for North Dakota.

The Company proposed to increase its net supply entitlements from Great Lakes Transmission Company (GLGT), and ANR Pipeline Company (ANR), and decrease its net supplies from Northern Natural Gas (NNG) and Viking Gas Transmission Company (VGT). The net change is an increase of 2,887 Dekatherms (Dth) for the total Minnesota Company but only 153 Dth for the Minnesota jurisdiction. Because Xcel proposed to allocate more of the new capacity to North Dakota, the nominal increase in the reserve margin for Minnesota of 153 Dth would leave the reserve margin percentage at 6.1 percent.

Xcel also requested approval to recover certain Producer Demand and Storage costs from both firm and interruptible customers in the Company's monthly PGA, effective with the November 1, 2012 billings. The proposal is a carryover of a plan first presented in the Company's 2007-2008 demand-entitlement filing, Docket No. G002/M-07-1395 (2007-2008 Demand Entitlement) and again in Xcel's subsequent demand entitlement filings (Docket Nos. G002/M-08-1315, G002/M-09-1287, and G002/M-10-1163). The Commission has not yet acted on these filings.

Xcel also provided a summary of hedging transactions in place for the 2012-2013 heating season in response to reporting requirements established in the Commission's May 27, 2008 Order in Docket No. G002/M-08-46. In addition, the Company provided cost information regarding commodity and demand resources that enables analysis of the effect of changes in these costs on the rates for customers expected in the PGAs for 2012-2013.

II. DEPARTMENT'S ANALYSIS OF XCEL'S REQUEST

The Department's analysis of the Company's request includes a description and an evaluation of the Company's demand-entitlement petition. The Department discusses each part of the Company's request below.

A. XCEL'S PROPOSED DESIGN DAY LEVELS

1. Xcel's Customer Base

Xcel's service areas were unchanged from the 2011-2012 heating season to the 2012-2013 heating season. Xcel expects an increase of 155 firm customers in the Minnesota jurisdiction between these two periods (from 439,055 to 439,210).

2. Xcel's Forecast

Consistent with its approach since its 2004-2005 demand-entitlement filing, the Company used two forecast methodologies in its estimate of its Design Day requirement forecast for 2012-2013: the Actual Peak Use per Customer Design Day (UPC DD) and the Average Monthly Design Day (Avg. Monthly DD). The Department assesses the foundations of the methodologies below.

a. Actual Peak Use per Customer Design Day (UPC DD)

The UPC DD method employs a use-per-customer number of 1.57393 Dth to estimate the Design Day demand forecast, based on the actual use per customer on Thursday, January 29, 2004, the coldest day in recent years. Xcel multiplied the 1.57393 value by estimates of total firm customers in all of Xcel's service areas and added the contracted billing demand for Small and Large Demand Billed customers to arrive at the total expected Design Day demand for the Xcel system. Thus, the way customers are distributed among service areas does not affect the aggregate forecasts produced by the UPC DD method because the total number of customers and the resulting total volume is unchanged no matter where the customers are assigned.

If either cold temperatures or differences with the Avg. Monthly DD method indicate that the 1.57393 Dth Design Day usage-per-customer volume is out of date, the Company stated that it will adjust the volume accordingly.

b. Average Monthly Design Day

The Avg. Monthly DD method is a statistical method that uses linear regression to estimate Design Day demand. Because Xcel has performed regression analyses on each demand area for both residential and commercial customers, the coefficients used to estimate use per customer vary from service area to service area. Consequently, the shifting of customers among demand areas can affect the aggregate forecasts produced by the Avg. Monthly DD method. However, the Company's service areas were unchanged from the 2011-2012 heating season to the 2012-2013 heating season.

c. Average Monthly Design Day Reliability

Xcel Energy used 60 months of data, or the five years covering January 2007-December 2012, as inputs for the Avg. Monthly DD method. The Department notes that Xcel has been increasing the data points each year in its Demand Entitlement filings since the Company made structural revisions to the Company's demand-area regions in 2005 (described in its 2008-2009 Demand Entitlement filing).

The 2011-2012 analysis was the first since the Company made the structural changes where the Company had 60 data points available in five calendar years. Thus, 72 data points from January 2006 to December 2012 are available for the 2012-2013 analysis. Xcel stated that it ran regressions using these 72 data points with the result that 25 percent of the demand-area regions' regressions had higher R-squared scores than when 60 data points were used. Because the R-squared scores were higher for a majority of the demand-area regions' regressions with 60 data points, the Company elected to continue using the analysis with 60 data points. Xcel stated that it believes that 60 data points captures current gas usage trends better than the longer timeframe.

The Department notes that in recent years, the long-term trend in natural-gas usage per customer has been downward. The preference in regression analysis is to have more data points than fewer because using more data points diminishes the effects of outlier data points and cyclical weather changes on the results. However, in this case, adding 12 data points that are six years old carries the risk of including data that is out of date given the long-term downward trend in usage. Whatever gain there is in reliability of the results from adding these older data points for the outlier and weather reasons is likely more than offset by the loss caused by using data from a year when per-customer usage generally was higher. Moreover, 60 data points is a large enough sample to address the problems that outliers and weather cause. Therefore, the Department concludes that Xcel's decision to use 60 data points in this analysis is reasonable.

The Company cited the R-squared values for customer groups within the various service areas as a way of evaluating the reliability of the forecasts. The Department will not repeat the general discussion of the R-squared value from previous comments (e.g. page 4 of the Department's comments in G002/M-11-1076), but notes that the results are similar to the results from 2011-2012; that is, 27 of the 42 R-squared values reported for the customer classes in Xcel's service areas are 95 percent or greater and 22 of these 27 predictions are in Minnesota service areas. Of the 15 cases in the Xcel system where the R-squared values drop below the 95-percent threshold, one small commercial case is in North Dakota, while six small commercial and eight large commercial groups are in Minnesota.

In five of the Minnesota cases of an R-squared value less than 95 percent, the Minnesota service-area commercial customer counts are less than 114. In small sample sizes like these, outliers in the populations can have large impacts on the regression analyses and their explanatory value. Meanwhile, the R-squared values for eight other service areas in the Minnesota cases are between 90.00 percent and 94.99 percent. In the one remaining case of an R-squared value for a service area not meeting the 95-percent mark, the customer count is 573 small commercial customers, and the R-squared score is 89.64, indicating that it is not a poor prediction. The one R-squared value for the North Dakota service area that does not meet the 95-percent standard is 87.45 percent (for 146 customers).

These scores suggest that the Avg. Monthly DD method produces acceptable forecasts, provided that other aspects of the regression analysis are acceptable. At times, random variations in demand factors in a given year, especially factors not recognized in the regression, can cause predictions and consumption to not line up. The Department concludes that Xcel's forecast method is reasonably sound.

The Department notes that the results of Xcel's UPC DD method generally resulted in higher forecasted requirements for design days than the Avg. Monthly DD method. This result could be due to various factors, such as the potential that the increase in natural gas use on very cold days may not be a linear response, the downward trend in energy use, or some other factors. In any case, the Department agrees with Xcel that the Company should continue to use the two methods to develop its Design Day estimate, updating the UPC DD method when appropriate.

3. Xcel's Forecasts

Xcel projected that its system (Minnesota and North Dakota) Design Day requirement will increase by 2,406 Dth to 788,298 Dth in the 2012-2013 heating season, or 0.3 percent. The Company's forecast of its Minnesota Design Day requirement is 702,159 Dth, a decline of 135 Dth and a drop of less than -0.1 percent. Meanwhile, the forecasted usage for North Dakota for 2012-2013 is 86,139 Dth, up 2,541 Dth, or 3.0 percent from 2011-2012.

Xcel's customer forecast shows the number of Minnesota customers increasing by 158 from 438,929 in the 2011-2012 forecast to 439,087 in the 2012-2013 forecast, an increase of less than 0.1 percent. The North Dakota customer count is forecasted to increase 2.1 percent to 48,750 in 2012-2013, up from 47,754 in 2011-2012.

The Department notes that the smaller rate of increase in forecasted Minnesota gas consumption volume indicates that the proportion of Design Day responsibility on the Xcel system has shifted from Minnesota to North Dakota. According to the petition, the consumption allocator for Minnesota for 2010-2011 is 89.07 percent, down from 89.36 percent the year before. Such small changes in apportionment in one year are not significant.

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The percentage changes for forecasted usage and customers in Minnesota in 2012-2013 are both less than 0.1 percent. It does not necessarily follow that the customer counts and usage track so closely. For example, North Dakota's customer count is forecasted to increase 2.1 percent in 2012-2013, while the gas usage forecast increase is 3.0 percent.

The Department concludes from the Company's descriptions of its forecasting techniques that Xcel's forecasting of Design Day levels are performed appropriately.

B. PROPOSED CHANGES IN XCEL ENERGY'S DESIGN DAY RESOURCES

Xcel's filing proposed changes in the resources used to meet its Design Day customer requirements. Overall, the Company's system firm supply entitlements rose slightly, from 833,811 Dth/day to 836,698 Dth/day, or 0.3 percent.

1. Northern Natural Gas Company Entitlements

The majority of Xcel's firm pipeline transportation contracts are with Northern Natural Gas (Northern). Most of these contracts were put in place in 2007 and run through 2017. The Company stated that it made one modification to its Northern entitlement levels since filing its 2011-2012 Demand Entitlement Filing. The change is an increase of 244 Dth/day at Brainerd effective November 1, 2012. This increase is intended to maintain a 5 percent reserve margin in the Brainerd service area. It is also part of an ongoing increase in Brainerd being phased in from 2011-2012 to 2014-2015. A second round of phased increases is expected between 2021-2022 and 2023-2024.

The additional capacity, which has an expiration date of October 31, 2024, is as follows:

Nov 1, 2013 – Oct 31, 2014	4,839 Dth/day
Nov 1, 2014 – Oct 31, 2021	5,075 Dth/day
Nov 1, 2011 – Oct 31, 2022	535 Dth/day
Nov 1, 2022 – Oct 31, 2023	291 Dth/day
Nov 1, 2023 – Oct 31, 2024	55 Dth/day

The Department requests that Xcel indicate in its reply comments what portions of the additional capacity are expected to be used to meet the needs of Xcel's Minnesota customers.

2. ANR Entitlements

Xcel plans to increase ANR entitlements by 9,000 Dth/day to a total of 66,500 Dth/day, scheduled for November 1, 2012 as part of a Precedent Agreement signed with ANR in 2008. This additional capacity would allow the Company to effectuate a Northern Chisago realignment discount option and to have gas supplies for the increased capacity that the Fargo lateral project required. The two projects were discussed in the 2010-2011 Demand Entitlement Filing (Docket No. G002/M-09-1287). The Northern Chisago realignment discount would save Xcel ratepayers $1.875 million per year, while the Fargo lateral project addressed Design Day capacity shortfalls that the Company had identified in that part of its system.

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3. Great Lakes Gas Transmissions (GLGT) Entitlements

Xcel is purchasing backhaul capacity on GLGT of 15,297 Dth/day (less 31 Dth/day for withdrawal fuel) to replace an equal volume of supply displacement contracts it signed for 2011-2012. The Company stated that the backhaul contract will be cheaper than the displacement alternative. The backhaul contract is scheduled to be in effect from November 1, 2012, to March 31, 2013. The volume of the contract is equal to Xcel's ANR Storage withdrawal capability. Xcel stated that if price changes make displacement more economical than backhaul, the Company can diversify its ANR transportation options by acquiring displacement contracts as at least part of its mix.

4. Viking Gas Transmission (Viking) Entitlements

Xcel planned to acquire backhaul capacity on Viking to transport 14,287 Dth/day of gas from Marshfield, Minnesota, to Fargo, North Dakota. This transportation on the interconnect between the systems is needed to serve the Fargo lateral project. The volume is equal to a volume transported by ANR to its terminus at Marshfield.

The Department has analyzed the above changes in Design Day entitlement resources. Xcel supported each change with a reasonable analysis. Although no new savings for ratepayers were identified, the Company continues to take advantage of discounts that it put in place as part of agreements it signed earlier and has increased the volumes acquired under those agreements as planned. The Department, therefore, concludes that the changes for 2012-2013 demand entitlements are reasonable.

C. CHANGE IN XCEL'S RESERVE MARGIN

Xcel proposed to maintain its projected Design Day reserve margin in Minnesota at 6.1 percent[2] in 2012-2013. See Department Attachment 1. Xcel stated that it bases its reserve margin on the firm resources necessary to meet projected firm customer demand plus the capability of either the largest pump at its Wescott facility used to vaporize liquefied natural gas (LNG) or either of its St. Paul metro propane-air peak-shaving plants. The capacity decision reflects Xcel's assessment of the most economical method of adding capacity to meet demand beyond the forecasted Design Day demand. The reserve margin balances protecting against the loss of a firm gas supply source and actual consumer demand under Design Day conditions with the likelihood of experiencing Design Day conditions. Xcel stated that its proposed reserve margin in Minnesota of 43,088 Dth/day is appropriate to meet its Design Day needs. The Company further stated that the most economical method of adding capacity often involves adding increments that do not precisely match expected changes in demand.

[2] The reserve margin increases nominally from 42,800 Dth/day to 43,088 Dth/day due to a small decrease in the Design Day requirement and a small increase in the natural gas available each day. The reserve margin percentage remains 6.1 percent when rounded to one decimal place.

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Xcel's proposed reserve margin is within the 5-7 percent range that serves as a rule of thumb in deciding whether a given margin is reasonable. The Department notes that Xcel's proposed 6.1 percent reserve margin is essentially the same as the prior, 2011-2012 reserve margin. The Company has stabilized its reserve margin after seeing it rise to 7.7 percent in 2009-2010. At that time, Xcel added the Fargo lateral, which caused its Design Day capacity to rise by a large volume. The Design Day requirement did not keep pace immediately, but has grown into the additional capacity in the intervening years.

In its Reply Comments in G002/M-09-1287 the Company explained that its experience with pipeline companies indicated that these counterparties rarely agree to 1-2 percent annual capacity additions. Thus, Xcel stated, it typically has to add capacity in increments that may temporarily exceed customer demand growth for a few years. The Company provided forecasts of its reserve margins from 2009-2010 to 2013-2014 that predicted 2011-2012 reserve margin of 5.0 percent. The reserve margin has not dropped enough to match that forecast, but the level is in keeping with the Company's prediction of where the reserve margin would move. The Department, therefore, concludes that the 2012-2013 reserve margin is reasonable.

D. CHANGES IN XCEL'S JURISDICTIONAL ALLOCATIONS

The previously noted percentage decrease of less than 0.1 percent in forecasted Minnesota usage and 3.0 percent forecasted increase in North Dakota usage is reflected in the new Minnesota Jurisdictional Allocation Factor and, as discussed above, in the allocations of new peak capacity in this petition to Minnesota and North Dakota. The allocation factor is calculated by dividing the Design Day forecasted demand for Minnesota (702,159 Dth/day) by the same demand for the Company's system (788,298 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which fell from 89.36 percent to 89.07 percent.

Small annual changes in the allocation factor such as that identified are almost inevitable. A change in a handful of customers in one state or the other can change the total numbers upon which the allocation factor is based and change the allocation between the states, but not significantly. The small change identified in the above analysis falls into this category. In addition, the Department is aware that the increased economic activity in North Dakota is increasing use of natural gas. Therefore, the Department concludes that Xcel's proposal is reasonable.

The Department notes that Xcel's filing indicates that the majority of the new capacity is needed to serve customers in North Dakota. The Department requests that Xcel show in its reply comments that the costs of the additional capacity will correspondingly be charged to customers in Minnesota and North Dakota.

E. CHANGES IN XCEL'S SUPPLIER RESERVATION FEES

Xcel stated that its Supplier Reservation fees have changed. The proposed decrease is **[TRADE SECRET DATA HAS BEEN EXCISED]** The new total expense level reflects these changes.

Therefore, the Department concludes that Xcel's proposal is reasonable.

F. XCEL'S PLANNED USE OF HEATING-SEASON FINANCIAL INSTRUMENTS

In compliance with reporting requirements of the Commission's Order in Docket No. G002/M-08-46, Xcel included a table summarizing the Company's hedging transactions for the 2012-2013 heating season. See Xcel Trade Secret Attachment 3. The information in the table is not sufficient to determine the cost to the Company of each transaction because the transactions had not closed at the time of the filing. Therefore, the portion of the total dollars shown for each transaction that relate to the Company's cap on hedging costs cannot be determined. The Department concludes that the Company has met its reporting requirement, and requests that Xcel provide updated information when it is available.

G. XCEL'S PGA COST RECOVERY PROPOSAL

Xcel proposed to reflect the costs associated with the demand entitlements in the petition in the PGA effective with November 1, 2012 billing cycles. The Department concludes that this effective date is reasonable because it reflects when its various supply and demand contracts for the 2012-2013 Heating Season demand entitlement take effect.

H. XCEL ENERGY'S PROPOSAL TO ASSIGN DEMAND COSTS TO INTERRUPTIBLE CUSTOMERS

Xcel Energy stated that interruptible sales customers are receiving the benefits of storage and balancing services on non-Design Days. Thus, a portion of these costs could justifiably be recovered from these customers. The Company, therefore, developed a proposal to make such an assignment of costs on a prospective basis and presented it in Comments in the Company's 2007-2008 Demand Entitlement filing (Docket No. G002/M-08-1315). Commission action in that docket is pending, as it is in the Company's 2008-2009 through 2011-2012 Demand Entitlement filings, in which the Company repeated the proposal.

The Department concluded in Comments dated October 7, 2008 that Xcel's proposal represented a systematic approach to determining when interruptible customers benefit from the services associated with demand costs. Therefore, the Department concluded that the proposal was reasonable. The Department position on the matter is unchanged in the current docket. As the Department stated in Docket No. G002/M-07-1395):

> The Company balances both firm and interruptible sales customers' requirements on a daily basis on both the Northern and Viking systems. Hence, the Company believes that a portion of these interstate pipeline balancing service demand charges should be allocated to the interruptible sales customers. The Xcel Energy proposal is to calculate a per-Dth cost by dividing total annual demand costs for the balancing services by budgeted annual sales to be paid on all gas commodity sales....

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> Xcel Energy's proposal represents a systematic approach to determining when interruptible customers benefit from the services associated with demand costs. Therefore, the [Department] concludes that the proposal is reasonable.

The Department concludes that, if approved by the Commission, any changes in allocating storage and balancing charges should be implemented on a going-forward basis.

I. PGA COST RECOVERY ANALYSIS

The demand entitlements in Xcel Attachment 2, Schedule 1, Page 1 of 2, represent the demand entitlements for which the Company's firm customers are currently paying. Department Attachment 2, using data provided by Xcel in response to an informal request, compares the July 2012 PGA costs to the November 2012 PGA costs for the several customer classes. The demand costs of gas shown in Department Attachment 2 are a blend of summer and winter rates for each class and are weighted for actual volumes consumed. The resulting per Dth cost changes for each class are added to the commodity cost of gas change, which is the same for each customer class, to arrive at total per Dth cost changes for the customer classes. The changes shown in Department Attachment 2 combine all of Xcel's proposed changes and results in the following annual rate effects:

- Annual demand cost decrease of $0.0174/Dth, or approximately $1.51 annually per year, for the average Residential customer consuming 87 Dth annually;
- Annual demand cost decrease of $0.0174/Dth, or approximately$4.94 annually , for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand cost decrease of $0.0172Dth, or approximately $25.16 annually, for the average Large Commercial customer consuming 1,463 Dth annually; and
- No change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers consuming, respectively, 8,114 Dth, 60,971 Dth, and 839,818 Dth annually. These customer classes are not allocated demand costs under the current cost allocation plan.

As noted above, the Department requests that Xcel indicate in reply comments that the allocation of costs to jurisdictions reflects cost causation reasonably. Pending review of that information, the Department concludes that the Company's proposal appears to be reasonable.

III. CONCLUSIONS AND RECOMMENDATIONS

The Department concludes that Xcel has sufficiently supported its:

- Proposed Design Day levels of capacity, including the derivation of its forecasting methods;
- Changes in Design Day resources;
- Maintenance of its in reserve margin;

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- Changes in jurisdictional allocations;
- Changes in supplier reservation fees; and
- Proposal to assign demand costs to interruptible customers.

Moreover, the Department concludes that Xcel has met its reporting requirement for planned use of heating-season financial instruments. The Department requests that Xcel provide updated cost information regarding hedging transactions for the 2012-2013 heating season when it is available.

Because Xcel's filing indicates that the majority of the new capacity is needed to serve customers in North Dakota, the Department requests that Xcel show in its reply comments that the costs of the additional capacity will be charged to customers in Minnesota and North Dakota, corresponding with the cost-causation of the two jurisdictions. The Department also requests that Xcel indicate in its reply comments what portions of the additional capacity are expected to be used to meet the needs of Xcel's Minnesota customers. Pending review of that information, the Department recommends that the Commission approve Xcel's proposed level of demand entitlements.

/sm

Docket No. G002/M-12-862
Demand Entitlement--PGA Cost Recovery Analysis

Residential	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/12)	Nov 2012 PGAs with Proposed Demand Entitlement Changes	Nov 2012 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.5042	$7.0824	$2.7422	$3.1604	$3.1604	-42.58%	-55.38%	15.25%	$0.4182
Demand Cost of Gas (1)	$0.9008	$1.0716	$0.9558	$0.9384	$0.9233	4.17%	-12.43%	-1.82%	($0.0174)
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	$5.5571	$5.9579	$5.9428	-27.91%	-39.08%	7.21%	$0.4008
Average Annual Usage (Dth)	87	87	87	87	87				
Average Annual Total Cost	$718.60	$850.43	$483.21	$518.06	$516.75	-27.91%	-39.08%	7.21%	$34.85
Average Annual Total Demand Cost of Gas	$78.33	$93.18	$83.11	$81.60	$80.28			**Current Allocation**	**($1.51)**
								Demand Costs to Non-Firm	**($2.83)**

Small Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/12)	Nov 2012 PGAs with Proposed Demand Entitlement Changes	Nov 2012 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$2.7422	$3.1604	$3.1604	-42.40%	-55.38%	15.25%	$0.4182
Demand Cost of Gas (1)	$0.8984	$1.0873	$0.9533	$0.9359	$0.9209	4.17%	-13.92%	-1.83%	($0.0174)
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	$4.9286	$5.3294	$5.3144	-30.05%	-42.73%	8.13%	$0.4008
Average Annual Usage (Dth)	284	284	284	284	284				
Average Annual Total Cost	$2,163.87	$2,643.22	$1,399.85	$1,513.68	$1,509.42	-30.05%	-42.73%	8.13%	$113.84
Average Annual Total Demand Cost of Gas	$255.17	$308.82	$270.76	$265.82	$261.56			**Current Allocation**	**($4.94)**
								Demand Costs to Non-Firm	**($9.20)**

Large Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/12)	Nov 2012 PGAs with Proposed Demand Entitlement Changes	Nov 2012 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$2.7422	$3.1604	$3.1604	-42.40%	-55.38%	15.25%	$0.4182
Demand Cost of Gas (1)	$0.8917	$1.0569	$0.9463	$0.9291	$0.9143	4.19%	-12.09%	-1.82%	($0.0172)
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	$4.9200	$5.3210	$5.3062	-30.08%	-42.61%	8.15%	$0.4010
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$13,561.15	$7,196.20	$7,782.72	$7,761.07	-30.08%	-42.61%	8.15%	$586.52
Average Annual Total Demand Cost of Gas	$1,304.24	$1,545.86	$1,384.10	$1,358.94	$1,337.29			**Current Allocation**	**($25.16)**
								Demand Costs to Non-Firm	**($46.80)**

Small Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/12)	Nov 2012 PGAs with Proposed Demand Entitlement Changes	Nov 2012 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4926	$7.0824	$2.7422	$3.1604		-42.46%	-55.38%	15.25%	$0.4182
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0757	#DIV/0!	#DIV/0!	#DIV/0!	$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	$3.7057	$4.1239	$4.1239	-36.12%	-48.13%	11.29%	$0.4182
Average Annual Usage (Dth)	8,039	8,039	8,039	8,039	8,039				
Average Annual Total Cost	$51,900.98	$63,909.34	$29,790.49	$33,152.40	$33,152.40	-36.12%	-48.13%	11.29%	$3,361.91
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$608.55			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$608.55**

Medium Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/12)	Nov 2012 PGAs with Proposed Demand Entitlement Changes	Nov 2012 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4696	$7.0824	$2.7422	$3.1604	$3.1604	-42.22%	-55.38%	15.25%	$0.4182
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0622	#DIV/0!	#DIV/0!	#DIV/0!	$0.0000
Distribution Margin	$0.4751	$0.3900	$0.4751	$0.4751	$0.4751	0.00%	21.83%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$7.4724	$3.2173	$3.6355	$3.6977	-38.84%	-51.35%	13.00%	$0.4182
Average Annual Usage (Dth)	72,766	72,766	72,766	72,766	72,766				
Average Annual Total Cost	$432,571.27	$543,733.86	$234,110.30	$264,540.89	$269,066.91	-38.84%	-51.35%	13.00%	$30,430.58
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$4,526.02			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$4,526.02**

Large Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/12)	Nov 2012 PGAs with Proposed Demand Entitlement Changes	Nov 2012 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.5501	$7.0824	$2.7422	$3.1604	$3.1604	-43.06%	-55.38%	15.25%	$0.4182
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0620	#DIV/0!	#DIV/0!	#DIV/0!	$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	$5.9847	$7.4389	$3.1768	$3.5950	$3.6570	-39.93%	-51.67%	13.16%	$0.4182
Average Annual Usage (Dth)	862,845	862,845	862,845	862,845	862,845				
Average Annual Total Cost	$5,163,843.40	$6,418,618.68	$2,741,095.05	$3,101,936.89	$3,155,433.29	-39.93%	-51.67%	13.16%	$360,841.84
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$53,496.40			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$53,496.40**

(1) Does not include 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	$0.4182	15.25%	-$0.0174	-1.82%	($1.51)	$34.85	7.21%
Small Commercial	$0.4182	15.25%	-$0.0174	-1.83%	($4.94)	$113.84	8.13%
Large Commercial	$0.4182	15.25%	-$0.0172	-1.82%	($25.16)	$586.52	8.15%
Small Interruptible	$0.4182	15.25%	$0.0000	#DIV/0!	$0.00	$3,361.91	11.29%
Medium Interruptible	$0.4182	15.25%	$0.0000	#DIV/0!	$0.00	$30,430.58	13.00%
Large Interruptible	$0.4182	15.25%	$0.0000	#DIV/0!	$0.00	$360,841.84	13.16%

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	$0.4182	15.25%	-$0.0325	-3.40%	($2.83)	$33.54	6.94%
Small Commercial	$0.4182	15.25%	-$0.0324	-3.40%	($9.20)	$109.58	7.83%
Large Commercial	$0.4182	15.25%	-$0.0320	-3.40%	($46.80)	$564.87	7.85%
Small Interruptible	$0.4182	15.25%	$0.0757	NA	$608.55	$3,970.47	11.29%
Medium Interruptible	$0.4182	15.25%	$0.0622	NA	$4,526.02	$34,956.61	14.93%
Large Interruptible	$0.4182	15.25%	$0.0620	NA	$53,496.40	$414,338.23	15.12%

Docket No. G002/M-12-862
Demand Entitlement Analysis--Minnesota Jurisdiction*

Northern States Power Company d/b/a Xcel Energy

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
Heating Season	(1) Number of Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Dth)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Design-Day Capacity (Dth)	(8) Change from Previous Year	(9) % Change From Previous Year	(10) Reserve Margin	(11) % of Reserve [(7)-(4)]/(4)
2012-2013**	439,210	155	0.04%	702,159	(135)	-0.02%	745,247	153	0.02%	43,088	6.14%
2011-2012**	439,055	2,461	0.56%	702,294	2,683	0.38%	745,094	1,313	0.18%	42,800	6.09%
2010-2011**	436,594	2,896	0.67%	699,611	5,124	0.74%	743,781	(4,486)	-0.60%	44,170	6.31%
2009-2010**	433,698	4,846	1.13%	694,487	9,482	1.38%	748,267	15,976	2.18%	53,780	7.74%
2008-2009**	428,852	(2,651)	-0.61%	685,005	1,288	0.19%	732,291	10,785	1.49%	47,286	6.90%
2007-2008**	431,503	7,088	1.67%	683,717	5,984	0.88%	721,506	25,249	3.63%	37,789	5.53%
2006-2007	424,415	2,845	0.67%	677,733	6,887	1.03%	696,257	4,568	0.66%	18,524	2.73%
2005-2006	421,570	10,584	2.58%	670,846	21,191	3.26%	691,689	16,569	2.45%	20,843	3.11%
2004-2005	410,986	9,353	2.33%	649,655	46,187	7.65%	675,120	31,805	4.94%	25,465	3.92%
2003-2004	401,633	5,826	1.47%	603,468	(4,388)	-0.72%	643,315	1,040	0.16%	39,847	6.60%
2002-2003	395,807			607,856			642,275			34,419	5.66%
Average:			1.16%			1.64%			1.68%		5.46%

	Firm Peak-Day Sendout						
Heating Season	(12) Firm Peak-Day Sendout (Dth)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess per Customer [(7) - (4)]/(1)	(16) Design Day per Customer (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak-Day Send per Customer (12)/(1)
2012-2013**	NA			0.0981	1.5987	1.6968	NA
2011-2012**	659,263	(16,314)	-2.41%	0.0975	1.5996	1.6970	1.5015
2010-2011	675,577	84,646	14.32%	0.1012	1.6024	1.7036	1.5474
2009-2010	590,931	(10,494)	-1.74%	0.1240	1.6013	1.7253	1.3625
2008-2009	601,425	15,551	2.65%	0.1103	1.5973	1.7076	1.4024
2007-2008	585,874	16,911	2.97%	0.0876	1.5845	1.6721	1.3578
2006-2007	568,963	31,303	5.82%	0.0436	1.5969	1.6405	1.3406
2005-2006	537,660	286	0.05%	0.0494	1.5913	1.6407	1.2754
2004-2005	537,374	(23,876)	-4.25%	0.0620	1.5807	1.6427	1.3075
2003-2004	561,250	26,865	5.03%	0.0992	1.5025	1.6017	1.3974
2002-2003	534,385			0.0870	1.5357	1.6227	1.3501
Average			2.05%	0.0770	1.5699	1.6297	1.3473

*-Some numbers may differ from Xcel Attachments due to rounding
**-Reflects the UPC DD method.

0.893626605

Attachment 1
Prepared by the Minnesota Department of Commerce, Division of Energy Resources

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. G002/M-12-862

Dated this **14th of September, 2012**

/s/Sharon Ferguson

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	Paper Service	No	OFF_SL_12-862_12-862
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_12-862_12-862
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_12-862_12-862
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_12-862_12-862
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Paper Service	No	OFF_SL_12-862_12-862
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_12-862_12-862
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_12-862_12-862
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Paper Service	No	OFF_SL_12-862_12-862
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_12-862_12-862
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_12-862_12-862
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_12-862_12-862

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_12-862_12-862
Ronald	Giteck	ron.giteck@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	Yes	OFF_SL_12-862_12-862
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	No	OFF_SL_12-862_12-862
Lloyd	Grooms	lgrooms@winthrop.com	Winthrop and Weinstine	Suite 3500 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No	OFF_SL_12-862_12-862
Todd J.	Guerrero	tguerrero@fredlaw.com	Fredrikson & Byron, P.A.	Suite 4000 200 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_12-862_12-862
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_12-862_12-862
Karen Finstad	Hammel	Karen.Hammel@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_12-862_12-862
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	OFF_SL_12-862_12-862

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Sandra	Hofstetter	N/A	MN Chamber of Commerce	7261 County Road H Fremont, WI 54940-9317	Paper Service	No	OFF_SL_12-862_12-862
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Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_12-862_12-862
Paula N.	Johnson		Interstate Power and Light Company	200 First Street SE PO Box 351 Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_12-862_12-862
Nancy	Kelly	nancyk@eurekarecycling.org	Eureka Recycling	2828 Kennedy Street NE Minneapolis, MN 55413	Electronic Service	No	OFF_SL_12-862_12-862
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_12-862_12-862
Nikki	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 South Main Street P.O. Box 68 Le Sueur, MN 56058	Paper Service	No	OFF_SL_12-862_12-862
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_12-862_12-862
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper Service	Yes	OFF_SL_12-862_12-862

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_12-862_12-862
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David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_12-862_12-862
John	Moir	N/A	City of Minneapolis	City Hall Rm 301 M 350 South 5th Street Minneapolis, MN 55415-1376	Paper Service	No	OFF_SL_12-862_12-862
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_12-862_12-862
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Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	444 Cedar St Ste 2050 St. Paul, MN 55101	Electronic Service	No	OFF_SL_12-862_12-862
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Paper Service	No	OFF_SL_12-862_12-862

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_12-862_12-862
Lisa	Veith		City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Paper Service	No	OFF_SL_12-862_12-862