BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

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

SERVICE DATE: October 16, 2015

DOCKET NO. G-002/M-14-654

In the Matter of a Petition by Northern States Power Company (Xcel) for Approval of Changes in Contract Demand Entitlements for the 2014-2015 Heating Season Supply Plan effective November 1, 2014

The above entitled matter has been considered by the Commission and the following disposition made:

1) **Approved Xcel's proposed level of demand entitlements as amended by its October 31, 2014 Supplemental filing;**

2) **Allowed Xcel to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2014;**

3) **Required Xcel to explain why daily interruptible data is not available for use in a design day regression analysis model in a compliance filing within 30 days of the Commission's order in this matter; and**

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

The Commission agrees with and adopts the recommendations of the Department of Commerce, which are attached and hereby incorporated into the Order. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

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MINNESOTA DEPARTMENT OF COMMERCE

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September 2, 2014 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-14-654

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 (Xcel or Company) for Approval of Changes in Contract Demand Entitlements.

The petition was filed on August 1, 2014. 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 proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2014 supplemental filing;
- allow Xcel to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2014 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2014;
- approve changes in the jurisdictional allocation for demand costs.

The Department also recommends that the Company provide, in its November 1, 2014 supplemental filing, an update on any hedging transactions that are entered into for the 2014-2015 heating season.

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

Sincerely,

/s/ MICHAEL N. ZAJICEK
Rates Analyst

MNZ/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

**PUBLIC DOCUMENT**

# BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

DOCKET NO. G002/M-14-654

## I. SUMMARY OF XCEL'S REQUEST

Northern States Power Company (Xcel or the Company) filed a demand entitlement petition (*Petition*) on August 1, 2014, with the Minnesota Public Utilities Commission (Commission). The Company requested Commission approval to place the Purchased Gas Adjustment (PGA) changes into effect on November 1, 2014. The Company stated that, in the event that the Commission does not act by November 1, 2014, the Company, pursuant to Minnesota Statute §216B.16, Subd. 7, Minnesota Rule 7825.2920, and Xcel's PGA tariffs, will provisionally place the PGA changes into effect on November 1, 2013, subject to later Commission approval.

In its *Petition*, Xcel requested approval from the Commission to implement its proposed interstate pipeline transportation, storage entitlement, and other demand-related contracts for 2014-2015 effective November 1, 2014. The Company requested that the adjustments be made through the PGA to reflect changes in its firm pipeline demand entitlement levels[1] as follows:

- increase its Minnesota jurisdictional design-day capacity by 9,010 dekatherms per day (Dth/day), about 1.27 percent (9,010 Dth/706,935 Dth);
- change the capacity resources used to meet the design-day requirements and increase the amount of capacity resources (total entitlements) for Minnesota by 12,029 Dth/day or 1.61 percent (12,029 Dth/749,325 Dth);

[1] The entitlement levels discussed in Xcel's filing are for the total Minnesota Company which encompasses the combined entitlements for Xcel'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 2, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

- with these changes in Minnesota's need and resources, the reserve margin increases slightly from 6.0 percent to 6.3 percent for Minnesota;
- slightly decrease the jurisdictional allocation to Minnesota (rather than North Dakota) to 88.42 percent from 88.95 percent 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 Entitlements for Xcel**

| Type of Entitlement | Proposed Dth Change | Rate | Months | Proposed Cost Change |
|---|---|---|---|---|
| NNG TFX (Nov-Mar) | 1,100 | $15.1530 | 5 | $83,341.50 |
| NNG TFX (Apr-Oct) | 1,100 | $5.6830 | 7 | $43,759.10 |
| NNG TFX (Nov-Mar) | 1,050 | $15.1530 | 5 | $79,553.25 |
| NNG TFX (Apr-Oct) | 1,050 | $5.6830 | 7 | $41,770.05 |
| NNG TFX (Nov-Mar) | 431 | $8.6272 | 5 | $18,591.62 |
| NNG TFX (Apr-Oct) | 431 | $4.0000 | 7 | $12,068.00 |
| NNG TFX (Nov-Mar) | 4,036 | $15.1530 | 5 | $305,787.54 |
| NNG TFX (Apr-Oct) | 4,036 | $5.6830 | 7 | $160,556.12 |
| VGT FT-A (Jan-Dec) | 15,000 | $4.4954 | 12 | $809,172.00 |
| VGT FT-A (Dec-Feb) | (10,542) | $3.7671 | 3 | $(119,138.30) |
| VGT FT-A (Dec-Feb) | 10,646 | $3.6918 | 3 | $117,908.71 |
| VGT FT-A (Apr-Oct) | (5000) | $3.4671 | 7 | $(121,348.50) |
| GLGT FT (Nov-Mar) | (6,706) | $9.4560 | 5 | $(317,059.68) |
| GLGT FT (Nov-Mar) | 9,248 | $14.6460 | 5 | $677,231.04 |
| ANR FTS (Jan-Dec) | 80 | $4.1600 | 7 | $2,329.60 |
| ANR FSS (Jan-Dec) | 84 | $2.0400 | 12 | $2,056.32 |
| ANR FSS (Jan-Dec) | 434 | $0.4000 | 12 | $2,083.20 |
| ANRS FS (Jan-Dec) | (6,049) | $1.0924 | 12 | $(79,295.13) |
| ANRS FS (Jan-Dec) | 170,880 | $0.0133 | 12 | 27,169.92 |
| Total for Change in Pipeline Entitlement | | | | $1,746,536.34 |

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 $1,746,536.34. This amount is for Minnesota and North Dakota customers. As discussed further below, the increases are related to various reliability needs across the Xcel service territory.

The Company proposed to increase its net supply entitlements from Northern Natural Gas (NNG or Northern), Viking Gas Transmission Company (VGT), and Great Lakes Transmission Company (GLGT). The net change is an increase of 18,654 Dth/day in total, but only 12,029 Dth/day for Xcel's Minnesota jurisdiction. Xcel noted that there is a small increase in the reserve margin – from 6.0 percent to 6.3 percent – due to an increase in entitlements in order to meet increased design-day consumption in the most economical manner.

Xcel also began treating storage-capacity demand charges as commodity costs instead of demand costs in the Company's July 2014 PGA as ordered in Xcel's grouped 2007-2013 Contract Demand Entitlement Filings.[2] Xcel also provided a summary of hedging transactions in place for the 2014-2015 heating season in response reporting requirements established in the Commission's May 27, 2008 *Order* in Docket No. G002/M-08-46.

## II. DEPARTMENT'S ANLAYSIS OF XCEL'S REQUEST

The Department's analysis of the Company's request includes a description and an evaluation of the Company's *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 expects an increase of 4,836 customers between the 2013-2014 and 2014-2015 heating seasons in the Minnesota jurisdiction (from 441,573 to 446,409). This includes Xcel's addition of two Minnesota communities in the process of converting from propane to natural gas service.[3]

#### *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 the 2013-2014 heating season: 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/day 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.[4] Xcel multiplied the 1.57393 Dth/day 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

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[2] Docket Nos. G002/M-07-1395, G002/M-08-1315, G002/M-09-1287, G002/M-10-1163, G002/M-11-1076, G002/M-12-862, and G002/M-13-663, Order dated June 9, 2014.
[3] In Docket No. G002/M-14-583 the Company requested New Area Surcharge riders for Barnesville, Holdingford, and Pillager.
[4] The Department notes that, while January 2014 was the coldest month in recent years, for design day purposes only the coldest single day is important. None of the days during January 2014 had temperatures as low as the January 29, 2004 low temperature.

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/day peak-day use-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 slope analysis to estimate design-day demand. Xcel performs a separate slope analysis on each demand area for both residential and commercial customers.[5] These separate demand areas have their own specific usage characteristics based on the input data; as such, 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. The Company's service areas were unchanged from the 2013-2014 heating season to the 2014-2015 heating season; therefore, any changes in the aggregate forecast numbers using the Avg. Monthly DD method are related to typical growth dynamics and data turnover (Xcel uses the 60 most recent months of data in its analysis), and to the usage characteristics of customers in a given demand area.

The Company summarizes its output statistics for each of its demand areas in Attachment 1, Schedule 1, of its *Petition*. The R-squared values for its various statistical models are generally greater than 0.90, which suggests that a high level of the predictive quality of the model is included in the input data for the specified variables. There are seven models that have R-squared values less than 0.90. These lower predictive models are generally associated with models that have a smaller number of customers. This result is not surprising, or even of a concern, because a smaller number of customers will inherently increase data variability because changes in consumption by a single customer, or group of customers will have a much greater impact on total consumption than an estimation group that has a larger number of customers.

The statistics presented by the Company in its *Petition* suggests that the Avg. Monthly DD method produces acceptable forecasts. In Docket No. G002/M-13-663, the Department noted that, while acceptable, the Avg. Monthly DD method might not represent the best option available for forecasting natural gas needs. The Department noted that there were potential issues related to the model assuming natural gas consumption is constant at all temperatures and that the average monthly design day estimates the average demand area

[5] Xcel has 15 separate demand areas. The demand areas that the Company conducts separate analyses on are as follows: Metro, Brainerd, Mainline, Mainline—Welcome, Willmar, Paynesville, VGT-Chisago, Watkins, Tomah, Red Wing, Grand Forks MN, Fargo MN, Grand Forks ND, Fargo ND, and WBI ND.

consumption based on a given temperature, instead of for a peak day where consumption is likely to be above average. After conversations with the Company it was concluded that utilizing a regression model based on daily consumption data would be very difficult due the fact that it would require estimation of daily interruptible load. Further Xcel's duel method approach counteracts some of the issues inherent in the Avg. Monthly DD method as it generally resulted in higher forecasted requirements than those produced using the UPC DD method. Thus the Department believes that Xcel's forecast methodology is reasonable and 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 (Minnesota and North Dakota) design-day requirements will increase by 14,899 Dth/day to 809,671 Dth/day in the 2014-2015 heating season, or a 1.8 percent increase. The Company's forecast of its Minnesota design-day requirements is 715,945 Dth/day, an increase of 9,010 Dth/day, or an increase of 1.3 percent. In addition, the forecasted North Dakota usage for 2014-2015 is 93,726 Dth/day, an increase of 5,889 Dth/day, or a 6.3% increase from the 2013-2014 heating season.

Xcel's customer forecast shows the number of Minnesota customers increasing by 4,836 from 441,573 in the 2013-2014 forecast to 446,409 in the 2014-2015 forecast, an increase of approximately 1.0 percent. The North Dakota customer count is forecasted to increase by approximately 4.0 percent to 52,067 in 2014-2015, up from 50,006 in 2013-2014.

The Department notes that the smaller rate of increase in forecasted Minnesota gas consumption indicates that the proportion of design-day responsibility on the Xcel system continues to shift from Minnesota to North Dakota. According to the *Petition*, the consumption allocator for Minnesota for the 2014-2015 heating season is 88.42 percent, down from 88.95 percent during the 2013-2014 heating season. The higher overall economic growth rates in North Dakota, relative to Minnesota, has been on-going and has led to incremental decreases in the allocator factor over the past few years. These small changes in apportionment year to year have not been significant.

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 CHANGED 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, which include entitlements for Minnesota and North Dakota, rose slightly, from 842,411 Dth/day to 861,065 Dth/day, or 2.2 percent.

### 1. *Northern Natural Gas*

The majority of Xcel's firm pipeline transportation contracts are with Northern. Most of these contracts were put in place in 2007 and run through October 2017. The Company made four changes to its Northern entitlements for its 2014-2015 heating season that serve peak demand. According to the Company, the first change relates to the addition of 3,981 Dth/day of incremental capacity at Brainerd, MN in order to ensure adequate capacity to meet demand for firm customers and maintain a 5 percent reserve margin.[6] The capacity at Brainerd, MN further increased by 55 Dth/day as capacity was scheduled to ratchet up for the 2014-2015 heating season. Combined, this amounted to a 4,036 Dth/Day increase.

Xcel indicated that the second change to its Northern entitlements relates to the addition of 1,100 Dth/day of incremental capacity for Red Wing, MN in order to provide sufficient incremental capacity and maintain a 5 percent reserve margin.[7]

The third change relates to an increase in capacity of 1,050 Dth/day at Kandiyohi, MN. Xcel stated that consistently higher than expected demand at Kandiyohi made additional capacity necessary in order for the Company to meet the updated design-day requirement, maintain a 5 percent reserve margin, and to serve expected propane conversions in the area.[8]

Finally, the fourth change relates to the addition of 431 Dth/day of incremental capacity for the St. Cloud and Becker, MN areas. Xcel indicated that additional capacity was needed to meet firm customer requirements at design-day temperatures.[9]

### 2. *Viking Gas Transmission*

The Company also made two adjustments to demand entitlements to serve peak demand on its VGT pipeline. First, Xcel allowed 10,542 Dth/day of capacity to expire and instead the Company plans to purchase 10,646 Dth/day of short-term capacity to meet design-day projections for the Grand Forks/East Grand Forks area, the Fargo/Moorhead area, and the Minneapolis/St. Paul metro area.[10]

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[6] *Petition* Attachment 1, pages 4 - 5.
[7] *Id.*
[8] *Id.*
[9] *Id.*
[10] *Petition* Attachment 1, pages 5-6.

Second, the Company added 15,000 Dth/day of year-round capacity with a Marshfield receipt point to serve new design-day needs identified this year. Xcel also proposed to decrease its contract delivery at [TRADE SECRET DATA HAS BEEN EXCISED] The Company did not provide an explanation for why they made this adjustment, but it appears that this delivery reduction would not jeopardize Xcel's ability to serve its design-day needs. Finally, the Company removed a [TRADE SECRET DATA HAS BEEN EXCISED].[11]

When these entitlement changes are added together, they result in an increase in peak-day entitlements of 18,654 Dth/day, which corresponds to the entitlement figures presented in Xcel's *Petition*. The Department has analyzed the above changes in design-day entitlement resources and each change appears reasonable to serve firm customers on a peak day. The Department, therefore, concludes that Xcel's proposed changes for 2014-2015 demand entitlements are reasonable.

### *C. CHANGE IN XCEL'S RESERVE MARGIN*

Xcel's proposed design-day reserve margin in Minnesota is 6.3 percent for 2014-2015, which is a slight increase from the 6.0 percent figure in 2013-2014 (DOC 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 vaporized 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 of 51,394 Dth/day, of which 45,409 Dth/day is for the Minnesota jurisdiction, 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. 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, therefore, concludes that the 2014-2015 reserve margin is reasonable.

### *D. CHANGES IN XCEL'S JURISDICTIONAL ALLOCATIONS*

The previously noted faster economic growth in North Dakota versus Minnesota is reflected in the revised Minnesota jurisdictional allocation factor which is used to allocate new peak capacity to Minnesota and North Dakota. The allocation factor is calculated by dividing the design day forecasted demand for Minnesota (715,945 Dth/day) by the same demand for the Company's system (809,671 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which fell from 88.95 percent to 88.42 percent.[12]

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[11] *Id.*
[12] *Petition* Attachment 1, page 8.

Small annual changes in the allocation factor are almost inevitable. A locational change of a handful of customers in one state or the other can change the total numbers upon which the allocation factor is based and therefore change the allocation between the states. Again, such changes are typically not significant. 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 proposed jurisdictional allocation change is reasonable.

*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.[13]

*F. XCEL'S PGA COST RECOVERY PROPOSAL*

Xcel proposed to reflect the costs associated with the demand entitlements in the *Petition* in the PGA effective November 1, 2014. The demand entitlements in Xcel Trade Secret Attachment 2, Schedule 1, Page 1 of 2, represent the demand entitlements for which the Company's firm customers will pay. Department Attachment 2 compares the July 2014 PGA costs to the anticipated November 2014 PGA costs for several customer classes. The resulting per Dth cost changes related strictly to changes in demand costs have the following annual rate effects.

- Annual demand cost increase by $0.0062/Dth, or approximately $0.54 annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand cost increase of $0.0059/Dth, or approximately $1.68 annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand cost increase of $0.0110/Dth, or approximately $16.09 annually, for the average Large Commercial customer consuming 1463 Dth annually; and
- No Change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers. These customer classes are not allocated demand costs under the current cost allocation plan.

Based on its review, the Department concludes that the Company's proposal appears to be reasonable. The Department is aware that minor changes in cost and entitlement levels may occur between the filing of these *Comments* and November, 1, 2014. As such, the Department recommends that the Company provide a supplemental filing on November 1, 2014 detailing final demand entitlement levels and costs.

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[13] *Id.*

## III. CONCLUSIONS AND RECOMMENDATIONS

The Department recommends that the Commission:

- approve Xcel's proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2014 supplemental filing;
- allow Xcel to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2014 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2014; and
- approve changes in the jurisdictional allocation for demand costs.

The Department also recommends that the Company provide, in its November 1, 2014 supplemental filing, an update on any hedging transactions that are entered into for the 2014-2015 heating season.

/lt

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November 25, 2014

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

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-14-654

Dear Dr. Haar:

Attached are the *Supplemental Comments* of the Minnesota Department of Commerce, Division of Energy Resources (Department) in response to the *Supplemental Filing* submitted in the following matter:

Petition of Northern States Power Company (Xcel or the Company) for Approval of Changes in Contract Demand Entitlements.

The *Supplemental Filing* was filed on October 31, 2014. 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

To ensure that the record is complete in this docket, the Department provides the following response to Xcel's October 31, 2014 *Supplemental Filing.* The Department recommends that the Commission accept the Company's proposed level of demand entitlement and allow Xcel to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2014.

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

Sincerely,

/s/ MICHAEL N. ZAJICEK
Rates Analyst

MNZ/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

# BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

# SUPPLEMENTAL COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. G002/M-14-654

## I. BACKGROUND

Northern States Power Company (Xcel or the Company) filed a demand entitlement petition (*Petition*) on August 1, 2014 for the 2014-2015 heating season, with the Minnesota Public Utilities Commission (Commission). On September 2, 2014 the Minnesota Department of Commerce, Division of Energy Resources (Department) filed *Comments* in response to the Company's *Petition.* In its *Comments*, the Department supported the Company's *Petition* and recommended that the Commission approve the Company's proposed cost recovery and demand entitlement levels, subject to possible adjustment in the Company's November 1, 2013 supplemental filing.

On October 31, 2014, The Company filed its *Supplemental Filing* which shows the final demand entitlement volumes and costs that will be charged to ratepayers. The Company notes that there have been several changes to the firm transport entitlement levels since the original August 1, 2014 filing. The Department responds to the *Supplemental Filing* below.

## II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S SUPPLEMENTAL FILLING

The Department's analysis of the Company's request includes a description and an evaluation of the Company's *Supplemental Filing*.

### *A. XCEL'S DEMAND ENTITLEMENT CHANGES*

The Company's *Supplemental Filing* lists several changes to the demand entitlement levels and costs shown in the August 1, 2014 *Petition.* First, Xcel indicated that Viking Gas Transmission (Viking) is unable to supply the Company's planned purchase of 10,646 decatherms (Dth) per day of firm, winter-only capacity. To account for the lack of availability from Viking, Xcel purchased all available capacity of Northern Natural Gas (Northern) from Carlton, MN to Chisago, MN. This amounts to 5,629 Dth/day of capacity, at a cost of

$286,000 more than the Viking capacity projected in the *Petition* due to Northern's higher reservation rates. To offset the remainder of the planned capacity purchase Xcel proposed to use its reserve capacity, reducing their reserve margin to 5.7 percent from a planned 6.3 percent reserve margin. This reserve margin is still within the Company's normal operating range.

Second, the Company also renewed some existing transportation and storage contracts with ANR Pipeline, ANR Storage, and Great Lakes Gas Transmission to enable Xcel to to meet the Company's design day requirements. By extending the terms of service, costs were reduced by $13,000 for this winter and by $560,000 over the next three years when considering reservation and usage costs.

Finally, the Company noted that demand rates for Viking have increased, resulting in an annual cost increase of $1,298,000.

The Department agrees that these changes are reasonable to serve firm customers on a peak day.

### *B. CHANGE IN XCEL'S RESERVE MARGIN*

In Xcel's original *Petition* additional demand entitlements were required, and the most economical manner of doing this raised the reserve margin from 6.0 percent in 2013-2014 to 6.3 percent in 2014-2015. Due to the inability of Viking to provide the planned additional entitlements, the Company revised its reserve margin down to 5.7 percent for 2014-2015. Xcel stated that its proposed reserve margin of 47,639 Dth/day, of which 42,390 Dth/day is for the Minnesota jurisdiction, is appropriate to meet its design-day needs (DOC Attachment 1). 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, therefore, concludes that Xcel's proposed 2014-2015 reserve margin is reasonable.

### *C. HEDGING TRANSACTIONS*

The Company updated its hedging transactions, showing that seven call options were executed for the 2014-2015 heating season, covering the Company's entire targeted supply quantity. The Department will not comment on these hedging transactions here, as our analysis will be included in a future Annual Automatic Adjustment Report.

### *D. XCEL'S PGA COST RECOVERY PROPOSAL UPDATE*

Xcel proposed to reflect the costs associated with its proposed demand entitlements in the PGA effective November 1, 2014. The demand entitlements in Xcel's Trade Secret Revised Attachment 2, Schedule 1, Page 1 of 2, represent the demand entitlements for which the Company's firm customers will pay. Department Attachment 2 compares the October 2014 PGA costs to the anticipated November 2014 PGA costs for several customer classes (DOC Attachment 2). The resulting per-Dth cost changes related strictly to changes in demand costs have the following annual rate effects.

- Annual demand cost increase by $0.0232/Dth, or approximately $2.02 annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand cost increase of $0.0233/Dth, or approximately $6.62 annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand cost increase of $0.0227/Dth, or approximately $33.20 annually, for the average Large Commercial customer consuming 1463 Dth annually; and
- No change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers. These customer classes are not allocated demand costs under the current cost allocation plan.

The bill impacts described above relate solely to changes in demand cost and are based on the difference between demand data provided by the Company. Based on its review, the Department concludes that the Company's proposal appears to be reasonable.

## III. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission:

- Approve Xcel's proposed level of demand entitlements as amended by its *Supplemental Filing;* and
- Allow Xcel to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2014.

/lt

Docket No. G002/M-14-654
Demand Entitlement Analysis-Minneosta Jurisdiction
DOC Attachment 1

**Northern States Power Company d/b/a Xcel Energy**

| | Number of Firm Customers | | | Design-Day Requirement | | | Total Entitlement Plus Peak Shaving | | | Reserve Margin | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| Heating Season | Number of Customers | Change from Previous Year | % Change From Previous Year | Design Day (Dth) | Change from Previous Year | % Change From Previous Year | Total Design-Day Capacity (Dth) | Change from Previous Year | % Change From Previous Year | Reserve Margin | % of Reserve [(7)-(4)]/(4) |
| 2014-2015** | 446,409 | 4,836 | 1.10% | 715,945 | 9,010 | 1.27% | 756,918 | 7,593 | 1.01% | 40,973 | 5.72% |
| 2013-2014** | 441,573 | 2,363 | 0.54% | 706,935 | 4,776 | 0.68% | 749,325 | 4,078 | 0.55% | 42,390 | 6.00% |
| 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: | | | 1.00% | | | 1.41% | | | 1.42% | | 5.56% |

| | Firm Peak-Day Sendout | | | | | | |
|---|---|---|---|---|---|---|---|
| | (12) | (13) | (14) | (15) | (16) | (17) | (18) |
| Heating Season | Firm Peak-Day Sendout (Dth) | Change from Previous Year | % Change From Previous Year | Excess per Customer [(7) - (4)]/(1) | Design Day per Customer (4)/(1) | Entitlement per Customer (7)/(1) | Peak-Day Send per Customer (12)/(1) |
| 2014-2015** | NA | | | 0.0918 | 1.6038 | 1.6956 | NA |
| 2013-2014** | 689,990 | 243 | 0.04% | 0.0960 | 1.6009 | 1.6969 | 1.5626 |
| 2012-2013** | 689,747 | 30,484 | 4.62% | 0.0981 | 1.5987 | 1.6968 | 1.5704 |
| 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** | | | 2.71% | 0.0880 | 1.5827 | 1.6706 | 1.4012 |

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

# Docket No. G002/M-14-654
## Demand Entitlement--PGA Cost Recovery Analysis
## DOC Attachment 2

| **Residential** | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | October PGA (10/1/14) | Nov 2013 PGAs with Proposed Demand Entitlement Changes | 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 | $3.7332 | $4.0675 | $4.4059 | -19.95% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.9008 | $0.9347 | $0.8215 | $0.8447 | -6.23% | -9.63% | 2.82% | $0.0232 |
| Distribution Margin | $1.8591 | $1.8591 | $1.8591 | $1.8591 | 0.00% | 0.00% | 0.00% | $0.0000 |
| Total per Dth Cost | $8.2641 | $6.5270 | $6.7481 | $7.1097 | -13.97% | 8.93% | 5.36% | $0.3616 |
| Average Annual Usage (Dk) | 87 | 87 | 87 | 87 | | | | |
| Average Annual Total Cost | $718.60 | $567.55 | $586.77 | $618.22 | -13.97% | 8.93% | 5.36% | $31.44 |
| Average Annual Total Demand Cost of Gas | $78.33 | $81.28 | $71.43 | $73.45 | | | **Current Allocation** | **$2.02** |

| **Small Commercial** | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | October PGA (10/1/14) | Nov 2013 PGAs with Proposed Demand Entitlement Changes | 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 | $3.7332 | $4.0675 | $4.4059 | -19.70% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.8984 | $0.9323 | $0.8246 | $0.8479 | -5.62% | -9.05% | 2.83% | $0.0233 |
| Distribution Margin | $1.2331 | $1.2331 | $1.2331 | $1.2331 | 0.00% | 0.00% | 0.00% | $0.0000 |
| Total per Dth Cost | $7.6186 | $5.8986 | $6.1252 | $6.4869 | -14.85% | 9.97% | 5.91% | $0.3617 |
| Average Annual Usage (Dk) | 284 | 284 | 284 | 284 | | | | |
| Average Annual Total Cost | $2,163.87 | $1,675.35 | $1,739.71 | $1,842.44 | -14.85% | 9.97% | 5.91% | $102.73 |
| Average Annual Total Demand Cost of Gas | $255.17 | $264.80 | $234.21 | $240.82 | | | **Current Allocation** | **$6.62** |

| **Large Commercial** | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | October PGA (10/1/14) | Nov 2013 PGAs with Proposed Demand Entitlement Changes | 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 | $3.7332 | $4.0675 | $4.4059 | -19.70% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.8917 | $0.9116 | $0.8097 | $0.8324 | -6.65% | -8.69% | 2.80% | $0.0227 |
| Distribution Margin | $1.2315 | $1.2315 | $1.2315 | $1.2315 | 0.00% | 0.00% | 0.00% | $0.0000 |
| Total per Dth Cost | $7.6103 | $5.8763 | $6.1087 | $6.4698 | -14.99% | 10.10% | 5.91% | $0.3611 |
| Average Annual Usage (Dk) | 1,463 | 1,463 | 1,463 | 1,463 | | | | |
| Average Annual Total Cost | $11,131.14 | $8,594.91 | $8,934.84 | $9,463.00 | -14.99% | 10.10% | 5.91% | $528.16 |
| Average Annual Total Demand Cost of Gas | $1,304.24 | $1,333.34 | $1,184.30 | $1,217.50 | | | **Current Allocation** | **$33.20** |

| **Small Interruptible** | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | October PGA (10/1/14) | Nov 2013 PGAs with Proposed Demand Entitlement Changes | 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 | $3.7332 | $4.0675 | $4.4059 | -19.78% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | NA | NA | NA | $0.0000 |
| Distribution Margin | $0.9635 | $0.9635 | $0.9635 | $0.9635 | 0.00% | 0.00% | 0.00% | $0.0000 |
| Total per Dth Cost | $6.4561 | $4.6967 | $5.0310 | $5.3694 | -16.83% | 14.32% | 6.73% | $0.3384 |
| Average Annual Usage (Dk) | 7,936 | 7,936 | 7,936 | 7,936 | | | | |
| Average Annual Total Cost | $51,235.93 | $37,273.01 | $39,926.33 | $42,611.88 | -16.83% | 14.32% | 6.73% | $2,685.54 |
| Average Annual Total Demand Cost of Gas | $0.00 | $0.00 | $0.00 | $0.00 | | | **Current Allocation** | **$0.00** |

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## Demand Entitlement--PGA Cost Recovery Analysis
## DOC Attachment 2

| **Medium Interruptible** | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | October PGA (10/1/14) | Nov 2013 PGAs with Proposed Demand Entitlement Changes | 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 | $3.7332 | $4.0675 | $4.4059 | -19.45% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | NA | NA | NA | $0.0000 |
| Distribution Margin | $0.4751 | $0.4751 | $0.4751 | $0.4751 | 0.00% | 0.00% | 0.00% | $0.0000 |
| Total per Dth Cost | $5.9447 | $4.2083 | $4.5426 | $4.8810 | -17.89% | 15.99% | 7.45% | $0.3384 |
| Average Annual Usage (Dk) | 64,709 | 64,709 | 64,709 | 64,709 | | | | |
| Average Annual Total Cost | $384,676.89 | $272,314.88 | $293,948.40 | $315,845.92 | -17.89% | 15.99% | 7.45% | $21,897.53 |
| Average Annual Total Demand Cost of Gas | $0.00 | $0.00 | $0.00 | $0.00 | | | **Current Allocation** | **$0.00** |

| **Large Interruptible** | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | October PGA (10/1/14) | Nov 2013 PGAs with Proposed Demand Entitlement Changes | 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 | $3.7332 | $4.0675 | $4.4059 | -20.62% | 18.02% | 8.32% | FALSE |
| Demand Cost of Gas (1) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | NA | NA | NA | $0.0000 |
| Distribution Margin | $0.4346 | $0.4346 | $0.4346 | $0.4346 | 0.00% | 0.00% | 0.00% | $0.0000 |
| Total per Dth Cost | $5.9847 | $4.1678 | $4.5021 | $4.8405 | -19.12% | 16.14% | 7.52% | $0.3384 |
| Average Annual Usage (Dk) | 745,979 | 745,979 | 745,979 | 745,979 | | | | |
| Average Annual Total Cost | $4,464,438.14 | $3,109,091.28 | $3,358,479.52 | $3,610,918.81 | -19.12% | 16.14% | 7.52% | $252,439.29 |
| Average Annual Total Demand Cost of Gas | $0.00 | $0.00 | $0.00 | $0.00 | | | **Current Allocation** | **$0.00** |

(1) Does not include demand smoothing
(2) WACOG held constant to isolate price changes related solely to demand changes.

| **Current Allocation**<br>Summary<br>Change from most recent PGA<br>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 | $0.3384 | 8.32% | $0.0232 | 2.82% | $2.02 | $31.44 | 5.36% |
| Small Commercial | $0.3384 | 8.32% | $0.0233 | 2.83% | $6.62 | $102.73 | 5.91% |
| Large Commercial | $0.3384 | 8.32% | $0.0227 | 2.80% | $33.20 | $528.16 | 5.91% |
| Small Interruptible | $0.3384 | 8.32% | $0.0000 | NA | $0.00 | $2,685.54 | 6.73% |
| Medium Interruptible | $0.3384 | 8.32% | $0.0000 | NA | $0.00 | $21,897.53 | 7.45% |
| Large Interruptible | FALSE | 8.32% | $0.0000 | NA | $0.00 | $252,439.29 | 7.52% |