COMMERCE DEPARTMENT

February 28, 2018

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-17-586

Dear Mr. Wolf:

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

> In the Matter of Northern States Power Company, doing business as Xcel Energy's (Xcel or the Company) Petition for Approval of Changes in Contract Demand Entitlements.

The Petition was filed on August 1, 2017 by:

> Lisa Peterson
> Manager, Regulatory Analysis
> Xcel Energy
> 414 Nicollet Mall
> Minneapolis, Minnesota 55401

On November 1, 2017, Xcel filed its Supplemental Filing.

The Department recommends that the Minnesota Public Utilities Commission (Commission) accept the Company's proposed level of demand entitlement, changes in the jurisdictional allocation for demand costs, and allow Xcel to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2017. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/lt
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G002/M-17-586

I. SUMMARY OF XCEL'S REQUEST

Northern States Power Company, doing business as Xcel Energy (Xcel or the Company) filed a demand entitlement petition (Petition) on August 1, 2017, 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, 2017. The Company stated that, in the event that the Commission does not act by November 1, 2017, 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, 2017, subject to later Commission approval.

On November 1, 2017, the Company filed its Supplemental Filing, which showed the final demand entitlement volumes and costs that would be charged to ratepayers. The Company noted three changes to the cost levels since the original August 1, 2017 filing.

In its Petition and Supplemental Filing, Xcel requested approval from the Commission to implement its proposed interstate pipeline transportation, storage entitlement, and other demand-related contracts for 2017-2018 effective November 1, 2017. 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 4,922 dekatherms per day (Dth/day), about 0.68% (4,922 Dth/725,225 Dth);
- change the capacity resources used to meet the design-day requirements and increase the amount of capacity resources (total entitlements) for Minnesota by 10,764 Dth/day or 1.41% (10,764 Dth/765,534 Dth);
- increase the reserve margin from 5.56% to 6.32% for Minnesota;

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[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.

- slightly decrease the jurisdictional allocation to Minnesota (rather than North Dakota) to 87.57% from 87.98% to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

Specifically, Xcel requested the following changes in demand volumes for the Minnesota Company. The Company has supply entitlements with three companies, Northern Natural Gas (NNG or Northern), Viking Gas Transmission Company (VGT), and ANR Pipeline (ANR). Table 1 shows a summary by pipeline. The full detail by contract is located in Department Attachment 1.

Table 1: Proposed Changes in Entitlements by Pipeline 2017-2018

Pipeline	Proposed Dth/day Change	Proposed Annual Cost Change
NNG	12,737	$ 1,875,173.47
VGT*	(16,371)	$ (466,642.26)
ANR	(4,894)	$ (303,844.72)
GLT	-	$ -

*VGT capacity of 16,371 Dth/day was replaced by 20,000 Dth/day of delivered supply. Given that a third party owns the pipeline transportation in a delivered transaction, the cost moved to the Commodity section.

As indicated in full detail in Department Attachment 1, Xcel proposed a number of changes in its demand entitlements that, in total, would increase costs from all source systems by approximately $1,104,686. This amount is for Minnesota and North Dakota customers. As discussed further below, the capacity increases are related to reliability needs across the Xcel system. The cost increases are due to not only the capacity increases on NNG, but also increased cost to contracts already owned and negotiated by Xcel.

The Company proposed increased supply entitlements from NNG. VGT will be supplied 20,000 Dth/day via delivered supply instead of the 16,371 Dth/day of capacity that the Company previously owned. Small reductions were made to ANR Pipeline and storage entitlements. The net change is an increase of 10,764 Dth/day. Xcel noted that there is an increase in the reserve margin, from 5.56% to 6.32%, due to the increase in entitlements relative to the increased design-day consumption, but the addition of entitlements is mainly to bolster specific regional sections of its system.

Xcel also continued treating storage-capacity demand charges as commodity costs instead of demand costs beginning with the Company's July 2014 PGA as ordered in Xcel's grouped 2007-

2013 Contract Demand Entitlement Filings.[2] Xcel provided a summary of hedging transactions in place for the upcoming heating season in response reporting requirements established in the Commission's May 27, 2008 and April 22, 2016 *Orders* in Docket No. G002/M-08-46 and Docket No. G002/M-16-88, respectively.

In Section II below, the Department's analysis of the Company's request includes the following areas:

- design-day requirements;
- proposed overall demand entitlement levels;
- reserve margins;
- jurisdictional allocation;
- supplier reservation fees; and
- the PGA cost recovery proposals.

II. DEPARTMENT'S ANLAYSIS OF XCEL'S REQUEST

A. XCEL'S PROPOSED DESIGN-DAY LEVELS

1. Xcel's Customer Base

Xcel expects an increase of 3,373 customers between the 2016-2017 and 2017-2018 heating seasons in the Minnesota jurisdiction (from 454,396 to 457,769). The Company projected that this increase in customer base would increase the Design Day (DD) requirements for Minnesota by 4,922 Dth.

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 2017-2018 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.

[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.

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. 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 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.

While January 6, 2014 was the coldest day, Xcel's analysis using the UPC DD and the Avg. Monthly DD resulted in an equivalent total expected design-day demand for the Xcel system.[3] If either cold temperatures or differences in results compared 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 linear regression analysis to estimate design-day demand. Xcel performs a separate regression on each demand area for both residential and commercial customers.[4] 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 2016-2017 heating season to the 2017-2018 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),[5] and to the usage characteristics of customers in a given demand area.

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[3] See Attachment 1, Schedule 3 page 1 of 2 and Attachment 1 Schedule 1 pages 1 through 5.

[4] 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.

[5] In its Attachment 1, page 3 of 8, Xcel stated the following:

> The Avg. Monthly DD calculation is based on linear regression using 60 data points, from January 2011-December 2016, as shown on Attachment 1, Schedule 1, Pages 2-5.

However, the period used in the regression analyses is from January 2012 through December 2016.

The Company summarizes its output statistics for each of its demand areas in Attachment 1, Schedule 1, of its *Petition*. Of the R-squared values for its various statistical models, 70% are 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. The models that have R-squared values less than 0.90 are generally associated with models that have a smaller number of customers. This result is not surprising, or even of 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* suggest 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 because it assumes natural gas consumption is constant at all temperatures; the Avg. Monthly DD estimates the average demand area 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 results in higher forecasted requirements than those produced using the UPC DD method.

In addition, the Department notes that the Company's METRO SM COMM Model had autocorrelation present in the regression analysis. The presence of autocorrelation in a regression analysis implies that the errors are not independent of each other. This would violate one of the basic assumptions in typical regression analysis which is that one normally assumes that the errors are all independent of one another. Hence, the presence of autocorrelation would affect the validity of the statistical tests that are typically applicable to regression analysis such as, for example, the coefficient of determination ("R-squared") test statistic, and the t-statistic. When forecasting with an ordinary least squares (OLS) regression model, absence of autocorrelation between the errors is very important. Thus, in the Company's future demand entitlement filings, Xcel should check and correct its regression models for autocorrelation

Thus, overall the Department believes that Xcel's forecast methodology is acceptable 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 9,560 Dth/day to 833,829 Dth/day in the 2017-2018 heating season, or a 1.2% increase. The Company's forecast of its Minnesota design-day requirements is 730,147 Dth/day, an increase of 4,922 Dth/day, or an increase of 0.7%. In addition, the forecasted North Dakota usage for 2017-2018 is 103,683 Dth/day, an increase of 4,638 Dth/day, or a 4.7% increase from the 2016-2017 heating season.

Xcel's customer forecast shows the number of Minnesota customers increasing by 3,373, from 454,258 in the 2016-2017 forecast to 457,631 in the 2017-2018 forecast, an increase of approximately 0.7%. The North Dakota customer count is forecasted to increase by approximately 2.8% to 56,599 in 2017-2018, up from 55,035 in 2016-2017.

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 2016-2018 heating season is 87.57%, down from 87.98% during the 2016-2017 heating season. The higher overall economic growth rate 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.

The Department concludes from the Company's descriptions of its forecasting techniques that Xcel's forecasting of design-day levels were performed appropriately.

B. DEMAND ENTITLEMENT LEVELS

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 870,123 Dth/day to 886,489 Dth/day, or 1.88%.

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 ran through October 2017. As described in last year's filing, Xcel already renewed the long-term contacts for another 10-year term through October 2027 due to a required one-year advanced notice for extension. As part of the extension, the renewal includes a $0.01/Dth rate increase beginning November 1, 2017.

In addition to the added renewal cost, the Company added three new entitlements for the 2017-2018 heating season that serve peak demand. According to the Company, 918 Dth/day of incremental capacity at St. Cloud, Minnesota, 3,333 Dth/day in the Lake Elmo, Minnesota area, and 8,486 Dth/day in the Twin Cities were added, effective November 1, 2017.[6]

2. Viking Gas Transmission

The Company also made one adjustment to demand entitlements needed to serve peak demand on its VGT pipeline. Xcel stated that it did not purchase short-term Viking capacity as it has over the prior several years (16,371 Dth/day for the 2016-2017 heating season). The Company evaluated its options and elected not to bid on the Viking open season because it would have cost ratepayers more as Xcel would have had to bid on the capacity for the long-term basis. Xcel determined that the best option was to acquire 20,000 Dth/day of delivered supply for the upcoming winter to cover the design-day need that was covered by the VGT seasonal contract. Although the delivered supply contract is not directly compared to the expiring VGT contract it still results a net increase of 3,629 Dth/day of capacity for the Company.

It is important to note that delivered supply is not reported in the demand section of the PGA, but instead in the commodity portion due to the fact that Xcel does not own the pipeline capacity and the third party's pipeline cost is imbedded with the commodity cost to form a delivered price. Therefore, the $466,642 in demand cost reduction from the non-renewal of last year's 6-month VGT contract is not a cost reduction, but rather a cost shift from the demand component to the commodity component.

3. Great Lakes Gas Transmission

Xcel renewed three Great Lakes firm capacity entitlements resulting in no change to contract quantity or price. The Company stated that the capacity supports withdrawal and summer injection of ANR storage quantities.[7]

4. ANR Pipeline

The Company renewed one contract with ANR storage to support greater supply flexibility and price protection due to the gas being injected in the summer and withdrawn in the winter. There was also a small reduction to capacity on ANR Pipeline pursuant to the ANR Pipeline tariff.

[6] Petition Attachment 1, page 4.
[7] Petition Attachment 1, page 5.

5. Conclusion

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 2017-2018 demand entitlements appear reasonable to accept.

C. TELEMETRY

On April 28, 2016, the Commission issued its Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724 for the 2015-2016 heating season (2016 Order). In the 2016 Order, Ordering point 13 states:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

On December 6, 2017, the Commission issued its Order in Docket Nos. G011/M-16-650, G011/M-16-651, and G011/M-16-652 for the 2016-2017 heating season (2017 Order). In the 2017 Order, Ordering point 4 states:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions.

Xcel does not use interruptible data in the development of its design day requirements. In Docket No. G002/M-16-649, Xcel stated the following:[8]

> We note that the Commission has asked the Department to examine whether the inclusion of telemetered data would yield

[8] Docket No. G002/M-16-649 at Attachment 1 pages 3-4 of 7.

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

In addition, the Department requested information from Xcel addressing the 2016 and 2017 Orders noted above. (See Department Attachment 6). Typically, given the long-term nature and size of interstate pipeline contracts, it is not clear to the Department how use of telemetering would "reduce costs." Please see pages 7 – 15 of the Department's January 29, 2018 Comments in Docket No. G011/M-17-588 for our response to the Commission's above requests.

D. RESERVE MARGIN

Xcel's proposed design-day reserve margin in Minnesota is 6.32% for 2017-2018, which is a slight increase from the 5.56% figure in 2016-2017. As the Company stated, the reserve margin serves to protect against the loss of a firm gas-supply source and the risk of actual consumer demand exceeding the design-day. Xcel stated that its proposed reserve margin of 46,151 Dth/day, as shown in further detail below in Department Attachment 2, is appropriate to meet its design-day needs. Xcel further stated the following:[9]

> To our knowledge, reserve levels are not set or specified by any state or federal agency for utility gas service. However, the Commission has generally found between 5 and 7 percent to be reasonable. We plan for no system outages related to upstream resources when considering our gas reserve margin. Any outage could result in the loss of heat for our customers during some of the coldest parts of the year and would necessitate extraordinary and time-consuming measures to resume service. We deem such an event unacceptable and design our system and entitlements accordingly.

[9] See Petition at Attachment 1, page 7 of 8.

> This use of reserve margin differs from the electric industry. For the electric transmission system managed by the Midwest Independent System Operator (MISO), for example, the reserve margin is two to three times higher than our gas reserve margin and based on an assumed loss of load one day in every ten years.

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 2017-2018 reserve margin is not unreasonable.

In general, the Department notes that, in contrast to the electric utility industry, natural gas reserve margins are utility-specific rather than regionally specific, as more fully discussed in Attachment 4. However, given Minnesota's efforts to expand natural gas use in under- and unserved areas, and the increasing use of natural gas for electricity generation, there is a growing need to more closely examine reserve margins and to integrate natural gas supply planning with electric resource planning. In light of this recognition, the Department has issued information requests (see Attachment 5) and intends to follow-up with the utilities to ask for updated information. The Department will review those responses, in addition to information provided in the annual service quality and annual automatic adjustment reports, to ascertain, among other things, the number and timing of interruptions (curtailments) that may be occurring, and the causes of those curtailments, as a first step in assessing whether the demand entitlements procured, including reserve margins in place at those times, were sufficient or justified, and to continue monitoring the growing inter-relationship between the natural gas and electric industries.

E. JURISDICTIONAL ALLOCATIONS

The 2017-2018 heating season jurisdictional allocation factor, which is used to allocate new peak capacity to Minnesota and North Dakota, remained within 0.50 percentage points of the projection for the prior heating season. The allocation factor is calculated by dividing the design-day forecasted demand for Minnesota (730,147 Dth/day) by the same demand for the Company's system (833,829 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which fell from 87.98% to 87.57%.[10]

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

[10] Petition Attachment 1, page 6.

changes are typically not significant. The Department concludes that Xcel's proposed jurisdictional allocation change is reasonable.

F. SUPPLIER RESERVATION FEES

Xcel stated that its Supplier Reservation fees have changed. The resulting net change is an increase of $159,657.50 annually based on the addition of 5,000 Dth/day year-over-year. Each of the supplier contracts is listed in the Trade Secret version of the Company filings. The Department will not comment on each individual contract, but has reviewed the filings and can confirm that Xcel's proposal appears reasonable.[11]

G. XCEL'S PGA COST RECOVERY PROPOSAL

Xcel proposed to reflect the costs associated with the demand entitlements identified in the Petition and updated in the Supplemental Filing in the PGA effective November 1, 2017. The demand entitlements in Xcel Attachment 2, Schedule 2, Page 1 of 2, represent the demand entitlements for which the Company's firm customers will pay. Department Attachment 3 compares the October 2017 PGA costs to the November 2017 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 costs increase by $0.0121/Dth, or approximately $1.05 more annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand costs increase by $0.0226/Dth, or approximately $6.42 more annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand costs increase of $0.0057/Dth, or approximately $8.34 more 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. 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 demand data provided by the Company. Based on its review, the Department concludes that the Company's proposal appears to be reasonable.

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[11] Supplemental Filing Attachment 1, Schedule 2, page 1.

III. CONCLUSIONS AND 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, 2017.

The Department requests that, in future demand entitlement filings, Xcel check the regression models it ultimately uses for autocorrelation and correct the model if autocorrelation is present.

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Department Attachment 1
Docket No. G002/M-17-586
Proposed Changes in Entitlements 2017-2018

Type of Entitlement	Proposed Dth/day Change	Rate	Months	Proposed Annual Cost Change
NNG TFX (Nov-Mar)	8,486	$ 15.1530	5	$ 642,941.79
NNG TFX (Apr-Oct)	8,486	$ 5.6830	7	$ 337,581.57
NNG TFX (Nov-Mar)	3,333	$ 6.1032	5	$ 101,709.83
NNG TFX (Apr-Oct)	3,333	$ 4.5000	7	$ 104,989.50
NNG TFX (Nov-Mar)	918	$ 9.3568	5	$ 42,947.71
NNG TFX (Apr-Oct)	918	$ 4.0000	7	$ 25,704.00
NNG TF5 (Nov-Mar)	(13,233)	$ 3.6480	5	$ (241,369.92)
NNG TF5 (Nov-Mar)	13,233	$ 3.9520	5	$ 261,484.08
NNG TF12 (Jan-Dec)	(31,801)	$ 3.6480	12	$ (1,392,120.58)
NNG TF12 (Jan-Dec)	31,801	$ 3.9520	12	$ 1,508,130.62
NNG TF5 (Nov-Mar)	(15,338)	$ 4.2560	5	$ (326,392.64)
NNG TF5 (Nov-Mar)	15,338	$ 4.5600	5	$ 349,706.40
NNG TF12 (Jan-Dec)	(32,608)	$ 4.2560	12	$ (1,665,355.78)
NNG TF12 (Jan-Dec)	32,608	$ 4.5600	12	$ 1,784,309.76
NNG TF5 (Nov-Mar)	(1,028)	$ 3.8000	5	$ (19,532.00)
NNG TF5 (Nov-Mar)	1,028	$ 4.1040	5	$ 21,094.56
NNG TF12 (Jan-Dec)	(30,118)	$ 3.8000	12	$ (1,373,380.80)
NNG TF12 (Jan-Dec)	30,118	$ 4.1040	12	$ 1,483,251.26
NNG TFX (Nov-Mar)	(48,576)	$ 3.6480	5	$ (886,026.24)
NNG TFX (Nov-Mar)	48,576	$ 3.9520	5	$ 959,861.76
NNG TFX (Jan-Dec)	(10,000)	$ 3.0400	12	$ (364,800.00)
NNG TFX (Jan-Dec)	10,000	$ 3.3440	12	$ 401,280.00
NNG TFX (Jan-Dec)	(1,680)	$ 3.9520	12	$ (79,672.32)
NNG TFX (Jan-Dec)	1,680	$ 4.2560	12	$ 85,800.96
NNG TFX (Nov-Mar)	(2,270)	$ 4.2560	5	$ (48,305.60)
NNG TFX (Nov-Mar)	2,270	$ 4.5600	5	$ 51,756.00
NNG TFX (Nov-Mar)	(8,546)	$ 3.8000	5	$ (162,374.00)
NNG TFX (Nov-Mar)	8,546	$ 4.1040	5	$ 175,363.92
NNG TFX (Apr-May, Sep-Oct)	(7,701)	$ 3.8000	5	$ (146,319.00)
NNG TFX (Apr-May, Sep-Oct)	7,701	$ 4.1040	5	$ 158,024.52
NNG TFX (Jul-Aug)	(3,376)	$ 3.8000	2	$ (25,657.60)
NNG TFX (Jul-Aug)	3,376	$ 4.1040	2	$ 27,710.21
NNG TFX (Nov-Mar)	(13,333)	$ 5.3736	5	$ (358,231.04)
NNG TFX (Nov-Mar)	13,333	$ 6.1032	5	$ 406,869.83
NNG TFX (Nov-Mar)	(9,373)	$ 8.6272	5	$ (404,313.73)
NNG TFX (Nov-Mar)	9,373	$ 9.3568	5	$ 438,506.43
VGT FT-A (Nov-Apr)*	(16,371)	$ 4.7507	6	$ (466,642.26)
ANR FSS (Jan-Dec)	(65)	$ 1.7820	12	$ (1,389.96)
ANR FSS (Jan-Dec)	(4,829)	$ 12.4690	7	$ (421,489.61)
ANR FSS (Jan-Dec)	4,829	$ 9.1300	7	$ 308,621.39
ANR FTS (Nov-Mar)	(4,829)	$ 7.8520	5	$ (189,586.54)
GLT FT (Nov-Mar)	(9,248)	$ 11.4420	5	$ (529,078.08)
GLT FT (Nov-Mar)	9,248	$ 11.4420	5	$ 529,078.08
GLT FT (Apr-Oct)	(895)	$ 11.4420	7	$ (71,684.13)
GLT FT (Apr-Oct)	895	$ 11.4420	7	$ 71,684.13
Total for Change in Pipeline Entitlement				**$ 1,104,686.49**
		Summary by Pipeline		
Pipeline	**Proposed Dth/day Change**			**Proposed Annual Cost Change**
NNG	12,737			$ 1,875,173.47
VGT*	(16,371)			$ (466,642.26)
ANR	(4,894)			$ (303,844.72)
GLT	-			$ -

*VGT capacity of 16,371 Dth/day was replaced by 20,000 Dth/day of delivered supply. Given that a third party owns the pipeline transpo

Department Attachment 2
Docket No. G002/M-17-586
Demand Entitlement Analysis*

	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)
2017-2018**	457,769	3,373	0.74%	730,147	4,922	0.68%	776,298	10,764	1.41%	46,151	6.32%
2016-2017**	454,396	3,766	0.84%	725,225	7,747	1.08%	765,534	3,382	0.44%	40,309	5.56%
2015-2016**	450,630	4,221	0.95%	717,478	1,533	0.21%	762,152	5,234	0.69%	44,674	6.23%
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:			0.98%			1.25%			1.28%		5.66%

	Firm Peak-Day Sendout			**Per Customer Metrics**			
	(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)
2017-2018**	NA			0.1008	1.5950	1.6958	NA
2016-2017**	733,711	14,382	2.00%	0.0887	1.5960	1.6847	1.6147
2015-2016**	719,329	31,828	4.63%	0.0991	1.5922	1.6913	1.5963
2014-2015**	687,501	(2,489)	-0.36%	0.0918	1.6038	1.6956	1.5401
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	(16,404)	-2.43%	0.0975	1.5996	1.6970	1.5015
2010-2011	675,667	84,736	14.34%	0.1012	1.6024	1.7036	1.5476
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			2.38%	0.0898	1.5862	1.6759	1.4485

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

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

Department Attachment 3
Docket No. G002/M-17-586
Demand Entitlement - PGA Cost Recovery Analysis*

Residential	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Most Recent PGA: 10/1/17	Proposed Demand Changes 11/1/17	% Change From Last Rate Case	% Change From Last Demand Change	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5042	$2.8801	$2.6718	$2.7995	-49.14%	-2.80%	4.78%	$0.1277
Demand Cost of Gas**	$0.9008	$0.8350	$0.8538	$0.8659	-3.87%	3.70%	1.42%	$0.0121
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.5742	$5.3847	$5.5245	-33.15%	-0.89%	2.60%	$0.1398
NNG TFX (Nov-Mar)	87	87	87	87				
Average Annual Total Cost	$718.60	$484.70	$468.22	$480.38	-33.15%	-0.89%	2.60%	$12.16
Average Annual Total Demand Cost of Gas	$78.33	$72.61	$74.24	$75.29			**Current Allocation**	**$1.05**

Small Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Most Recent PGA: 10/1/17	Proposed Demand Changes 11/1/16[1]	% Change From Last Rate Case	% Change From Last Demand Change	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.4871	$2.8801	$2.6718	$2.7995	-48.98%	-2.80%	4.78%	$0.1277
Demand Cost of Gas**	$0.8984	$0.8306	$0.8493	$0.8719	-2.95%	4.97%	2.66%	$0.0226
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.9438	$4.7542	$4.9045	-35.62%	-0.79%	3.16%	$0.1503
NNG TFX (Nov-Mar)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,404.16	$1,350.31	$1,393.00	-35.62%	-0.79%	3.16%	$42.69
Average Annual Total Demand Cost of Gas	$255.17	$235.91	$241.22	$247.64			**Current Allocation**	**$6.42**

Large Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Most Recent PGA: 10/1/17	Proposed Demand Changes 11/1/16[1]	% Change From Last Rate Case	% Change From Last Demand Change	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.4871	$2.8801	$2.6718	$2.7995	-48.98%	-2.80%	4.78%	$0.1277
Demand Cost of Gas**	$0.8917	$0.8306	$0.8492	$0.8549	-4.13%	2.93%	0.67%	$0.0057
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.9422	$4.7525	$4.8859	-35.80%	-1.14%	2.81%	$0.1334
NNG TFX (Nov-Mar)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,228.67	$6,951.21	$7,146.32	-35.80%	-1.14%	2.81%	$195.12
Average Annual Total Demand Cost of Gas	$1,304.24	$1,214.87	$1,242.07	$1,250.41			**Current Allocation**	**$8.34**

Small Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Most Recent PGA: 10/1/17	Proposed Demand Changes 11/1/16[1]	% Change From Last Rate Case	% Change From Last Demand Change	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.4926	$2.8801	$2.6718	$2.7995	-49.03%	-2.80%	4.78%	$0.1277
Demand Cost of Gas**	$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	$3.8436	$3.6353	$3.7630	-41.71%	-2.10%	3.51%	$0.1277
NNG TFX (Nov-Mar)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,235.93	$30,503.13	$28,850.06	$29,863.49	-41.71%	-2.10%	3.51%	$1,013.43
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00			**Current Allocation**	**$0.00**

Medium Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Most Recent PGA: 10/1/17	Proposed Demand Changes 11/1/16[1]	% Change From Last Rate Case	% Change From Last Demand Change	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.4696	$2.8801	$2.6718	$2.7995	-48.82%	-2.80%	4.78%	$0.1277
Demand Cost of Gas**	$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	$3.3552	$3.1469	$3.2746	-44.92%	-2.40%	4.06%	$0.1277
NNG TFX (Nov-Mar)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,676.89	$217,112.93	$203,634.05	$211,897.39	-44.92%	-2.40%	4.06%	$8,263.34
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-16-649)	Most Recent PGA: 10/1/17	Proposed Demand Changes 11/1/16[1]	% Change From Last Rate Case	% Change From Last Demand Change	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5501	$2.8801	$2.6718	$2.7995	-49.56%	-2.80%	4.78%	$0.1277
Demand Cost of Gas**	$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	$3.3147	$3.1064	$3.2341	-45.96%	-2.43%	4.11%	$0.1277
NNG TFX (Nov-Mar)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,464,438.14	$2,472,704.05	$2,317,316.63	$2,412,578.14	-45.96%	-2.43%	4.11%	$95,261.52
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00			**Current Allocation**	**$0.00**

Current Allocation Summary Change from most recent PGA Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.1277	4.78%	$0.0121	1.42%	$1.05	$12.16	2.60%
Small Commercial	$0.1277	4.78%	$0.0226	2.66%	$6.42	$42.69	3.16%
Large Commercial	$0.1277	4.78%	$0.0057	0.67%	$8.34	$195.12	2.81%
Small Interruptible	$0.1277	4.78%	$0.0000	NA	$0.00	$1,013.43	3.51%
Medium Interruptible	$0.1277	4.78%	$0.0000	NA	$0.00	$8,263.34	4.06%
Large Interruptible	$0.1277	4.78%	$0.0000	NA	$0.00	$95,261.52	4.11%

*Some numbers may differ from Xcel Attachments due to rounding

**Includes demand smoothing

Attachment 4 – Natural Gas Reserve Margins

Below is a brief summary of the differences between the electric and natural gas industries in terms of setting reserve requirements, and the factors impacting how natural gas reserve margins are developed.

A retail natural gas distribution utility acquires the product demanded by its customers through contracting with a natural gas transmission pipeline company for certain levels of product for specified time periods. A vertically integrated electricity provider supplies most of its own product (through owned generation or purchased power agreements), relying on the non-contractual market [for Minnesota, the Midcontinent Independent System Operator (MISO)] when consumption exceeds the levels planned or outages prevent supply at the planned levels. Thus, the electric industry structure requires interdependency among market participants, necessitating a common reserve margin to ensure balanced reliance on the larger system.

A major factor differentiating electricity and natural gas is a greater availability of storage options for natural gas as opposed to electricity. For example, if natural gas utilities are aware in advance of a cold snap in weather, they may use “line pack” as a way to “store” natural gas temporarily in the pipe for use during the cold snap. Further, when natural gas consumption exceeds the levels planned or pipelines are damaged causing a loss of supply, natural gas utilities may turn to their own storage resources, propane or liquefied natural gas peaking plant capabilities, curtail natural gas supplied to interruptible customers, or seek to procure capacity release opportunities, if any exist at that time and location.

Moreover, there is not an energy market or independent system operator to dispatch resources, as there is in the electric industry, in part because the natural gas systems are less interdependent on each other. Therefore, reserve margins on the natural gas system are utility-specific rather than regionally specific.

Natural gas reserve margins are not only utility-specific, but there may in effect be different levels of reserve margins in different places on the natural gas utility’s system. That is, it may be misleading to consider one reserve margin as accurately reflecting the ability of the utility to supply natural gas. A utility may have what appears to be a reasonable overall reserve margin, but still experience curtailments at a certain Town Border Station (TBS) due to the inability to physically move available product to that location. Similarly, a utility may have what appears to be an unreasonably low reserve margin but still have large reserve margins at certain locations, with the flexibility (through a loop, for example) to move the excess gas to another location to avoid curtailments.

Appropriate natural gas reserve margins can be set using various methods. For instance, a natural gas reserve margin could be set equal to the output capability of a utility's propane or liquefied natural gas peaking plant because the function of that peaking plant is to provide product at times when demand exceeds pipeline supply. Therefore, it may be reasonable to set the reserve margin at the level of the peaking plant's capacity in order to ensure that peak demand is met should the peaking plant experience an outage. (This approach is called an "N minus one" approach.)

Natural gas utilities procure pipeline supply considering both minimum demand and peak demand. Minimum usage (minimum day load) on a winter day is estimated to ensure that base load gas acquired does not exceed the ability of the company to either use the gas for system load or to inject the gas into storage. The natural gas design-day calculation estimates the maximum firm demand anticipated under the most extreme weather conditions. The extent to which a utility procures entitlements in excess of its estimate of maximum firm demand may vary by utility depending on factors such as how much storage is in place, whether the utility has a peaking plant and the size of the plant, past experience, and expectation for load growth. Further, there may be a need to procure additional entitlements to meet design-day requirements, but the pipeline suppliers may not offer entitlements at the specific level needed. The excess amount procured could be considered, or proposed as, that utility's reserve margin, but the percentage represented by that reserve margin is not the result of a calculation; rather, it was dictated by the need to fulfill design-day needs. In other words, under certain circumstances a reserve margin may exceed the levels traditionally considered reasonable by the Commission, but be legitimately dictated by the availability of supply to meet the obligation to provide firm service.

At this time, the Commission should continue to determine the reasonableness of natural gas resources on a case-by-case basis.

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G999/AA-16-524	☐Nonpublic ☒Public
Requested From:	All Regulated Natural Gas Utilities	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us; michael.ryan@state.mn.us; angela.byrne@state.mn.us; stephen.rakow@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **22**
Topic: Distribution Planning
Reference(s): Department Information Request No. 18

Request:

Please provide the above reference, including any and all subparts, updated to the most recent date available.

If this information has already been provided in the application or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G999/AA-16-524	☐Nonpublic ☒Public
Requested From:	All regulated gas utilities	Date of Request: 3/10/2017
		Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **18**
Topic: Distribution Planning

Request:

A. Please provide a detailed discussion of how the utility plans, constructs, and maintains its distribution system. As part of this response, include a discussion about how the utility decides to add capacity or expand in to new, or growing, service territory.
B. Please provide daily throughput data, by each individual Town Border Station (TBS) or delivery point, on the utility's system since November 1, 2012. If available, please provide these data divided by firm, interruptible, and transport load. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
C. Please provide the number of interruption days, by TBS or delivery point, by month since November 2012. To the extent possible, please identify the number of interruption days that are non-weather related (*e.g.,* reliability purposes). Please also provide these data in Microsoft Excel format with all links, and formulae intact.
D. Please provide, on a daily basis since November 1, 2012 by TBS or delivery point, the maximum deliverable throughput by customer type. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
E. Please provide, by TBS or delivery point, on a daily basis since November 1, 2012 the percentage of deliverable capacity subscribed by the utility. If applicable, please identify other parties, and their percentages of subscribed capacity, at the TBS. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
F. Please provide the following forecasted data, in Microsoft Excel format with all links and formulae intact, by TBS, or delivery point, for the next three heating seasons. If the utility expects daily fluctuation, please provide these data on a daily basis:
    a. Total utility throughput, if possible, divided by customer type (*i.e.*, firm, interruptible, transport); and
    b. Expected firm and total throughput available at the TBS or delivery point.
G. Please provide maps, by county, identifying the location (and name) of any, and all, TBSs or delivery points on the utility's system. If possible, please provide these maps in pdf and GIS executable formats.

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G999/AA-16-524	☐Nonpublic ☒Public
Requested From:	All regulated gas utilities	Date of Request: 3/10/2017
		Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

a. Please identify, by county, on the maps in Part F, the location of any, and all, transmission assets on the utility's system.
b. If the utility has an affiliate transmission or intrastate pipeline utility, please also identify these assets on the maps provided in Part F, by county.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

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☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	G002/M-17-586		
Response To:	MN Department of Commerce	Information Request No.	3
Requestor:	Sachin Shah/Michael Ryan		
Date Received:	December 6, 2017		

Question:

Topic: Demand Entitlement
Reference(s): August 16, 2017 Public Utilities Commission (Commission or PUC) Staff Briefing Papers in Docket No. G011/M-16-650

On page 12 of the Briefing Papers, staff stated the following:

> If the Department has not begun the investigation, requested in Commission Order Point 13, in Docket Nos. 15-722, 15-723, and 15-724, into how other natural gas utilities acquire and use daily customer usage data:
>
> > 5. Request the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

The final order in Docket No. G011/M-16-650 has not been issued, but in the agenda meeting the Commission and staff expressed interest having the Department review the use of metered daily interruptible data. Based on this anticipated order, please:

- Provide general discussion on how interruptible customers and their data are incorporated into design-day analysis;
- Provide general discussion of telemetering requirements for interruptible customers;

- Explain if the Company has any interruptible customers without telemetering and if so, provide the number of interruptible customers without telemetering and explain why this is the case;
- Reference and provide any tariff language that requires interruptible customers to have telemetering; and
- Explain if the Company has reduced its design day and/or interstate pipeline demand entitlements in the prior five years as a result of having daily interruptible data.

If this information has already been provided in the application, written testimony or in response to an earlier Department information request (IR), please identify the specific testimony cite(s) or IR number(s).

Response:

Interruptible Customers and their data in design-day analysis
As we detail in our Demand Entitlements filing, we use two methods to estimate design day requirements. First, as approved in our 2004-05 filing, we use the Actual Peak Use per Customer (UPC) method. The UPC method established a Dth Use per Customer on the coldest day (Jan 29, 2004 -15 degrees), by taking total throughput minus all interruptible and 3rd party use divided by the number of firm retail customers. Annually, we use the UPC and our current forecast of firm retail customers to establish the projected design day requirements.

Second, we continue to use our Average Monthly Design Day methodology. This uses firm retail customers billed usage and monthly Heating Degree Days (HDD) within a linear regression for the previous five years (60 months). The regression then estimates a projected design day based on forecasted firm retail customers and design temperature.

The UPC model more precisely represents the effects of fluctuating temperature on gas use. The Avg. Monthly model provides more detail on our regional source of requirements, and customer class specificity. However, because the data is monthly it may smooth the effects of large temperature swings, and so may understate the use on the coldest days.

Interruptible customers and their data are not a part of either model. We continue to maintain and compare both methodologies. We believe that the models are adequately estimating natural gas needs during cold weather and the current use per customer estimate should be maintained. However, we will continue to evaluate the models each year to determine if they are adequately projecting natural gas supply needs and adjust the use per customer estimate if necessary.

Telemetering requirements for interruptible customers
The customer has to provide (at the customer's expense) an analog phone line in order for hourly time-stamped consumption data to be retrieved remotely by an Xcel Energy-owned communication device.

Interruptible customers without telemetering
We have 170 interruptible customers without telemetry installed. Some interruptible customers do not have telemetering because they have never installed a phone line or they have not maintained it. Consistent with our tariff, those customers have Cellnet meters.

Tariff language requiring interruptible customers have telemetering
From our Minnesota Gas Rate Book, MPUC No. 2:

Interruptible Service
Rate Codes: Small 105 & 111, Medium 106, Large 120
Sheet No. 5-10, Revision 8

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company. Service shall be provided through a Company owned and maintained meter with telemetering or other automated meter reading capabilities installed. Customer shall provide, install, and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment.

If the Customer fails to provide phone and/or electrical service that meets Company requirements, then the Company may take one of the following actions and charge the Customer for the costs:

1. Equip customer with cellular meter reading technology, if service is available, for an initial cost of $1,800 and a monthly cost of $10.00 for cellular service and maintenance.
2. Equip customer with a recording instrument for an initial cost of $2,100 and a monthly cost of $52.44 for reading the recording instrument manually each month by the Company via laptop computer.
3. A Small Interruptible customer that meets size requirements may be moved to service on Commercial Firm Service (does not require telemetering).

Interruptible Transportation Service
Rate Codes: Small 123, Medium 107, Large 124
Sheet No. 5-16, Revision 4

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company. Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station. Service shall be provided through a Company owned and maintained meter with telemetering or other automated meter reading capabilities installed. Customer shall provide, install, and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment.

If the Customer fails to provide phone and/or electrical service that meets Company requirements, then the Company may take one of the following actions and charge the Customer for the costs:

1. Equip customer with cellular meter reading technology, if service is available, for an initial cost of $1,800 and a monthly cost of $10.00 for cellular service and maintenance.
2. Equip customer with a recording instrument for an initial cost of $2,100 and a monthly cost of $52.44 for reading the recording instrument manually each month by the Company via laptop computer.

Design day and/or interstate pipeline demand entitlements

As mentioned above, interruptible customers and their use data are not a part of either of the design day models we employ. Their use is not present in either data set, and so does not need to be removed. As a result, we have not adjusted our design day in the past five years as a result of interruptible customer data.

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