COMMERCE DEPARTMENT

October 30, 2020

Will Seuffert
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-20-633

Dear Mr. Seuffert:

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 July 31, 2020 by:

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

The Department will provide its final recommendations to the Minnesota Public Utilities Commission (Commission) after the Company files its Update or Supplement on November 2, 2020. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ar
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G002/M-20-633

I. SUMMARY OF XCEL'S REQUEST

Northern States Power Company, doing business as Xcel Energy (NSP, Xcel or the Company) filed a demand entitlement petition (Petition) on July 31, 2020, 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, 2020. The Company stated that, in the event that the Commission does not act by November 1, 2020, 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, 2020, 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 2020-2021 effective November 1, 2020. 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 (DD) capacity by 5,496 dekatherms per day (Dth/day), about 0.74% (5,496 Dth/743,696 Dth);
- change the capacity resources used to meet the design-day requirements and decrease the amount of capacity resources (total entitlements) for Minnesota by 1,202 Dth/day or 0.15% (1,202 Dth/792,833 Dth);
- decrease the reserve margin from 6.61% to 5.66% for Minnesota;
- slightly decrease the jurisdictional allocation to Minnesota (rather than North Dakota) to 87.18% from 87.57% to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

The Company has supply entitlements with five companies, Northern Natural Gas (NNG or Northern), Viking Gas Transmission Company (VGT), ANR Pipeline (ANR), Great Lakes Gas Transmission Company (GLGT), and Williston Basin (WBI). Xcel requested approval of renewals of existing contract entitlements for ANR (and some minor changes), GLGT, and Viking. Table

[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 1, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

1 shows a summary by pipeline. The full detail by contract is located in Attachment 1, Schedule 2 and Attachment 2, Schedule 1 of the Petition.

Table 1: Proposed Changes in Entitlements by Pipeline 2020-2021

Pipeline	Proposed Dth/day Change	Proposed Annual Cost Change
NNG	-	$ (4,482,341.06)
VGT	-	$ (1,670,937.62)
ANR	(16)	$ (417.02)
GLT	-	$ -
WBI	-	$ -

As indicated in Attachments 1 and 2 of the Petition, Xcel proposed a number of changes in its demand entitlements that, in total, would decrease costs from all source systems by approximately $6,065,529. This amount is for Minnesota and North Dakota customers. As discussed further below, the capacity changes are related to reliability needs across the Xcel system. The cost decreases are due to not only the capacity renewals, but also the decreased cost of contracts already owned and negotiated by Xcel for NNG, VGT, and ANR.

The Company proposed no changes to be made to NNG, VGT, GLGT, and WBI Pipeline capacity and entitlements. The net change to the design-day capacity is a decrease of 1,202 Dth/day on a Minnesota jurisdictional basis. Xcel noted that there is a decrease in the reserve margin, from 6.61% to 5.66%, due to the small decrease in entitlements relative to the increased design-day consumption. Xcel also stated that the "reserve margin is appropriate given the need to balance the uncertainty of: (a) experiencing DD conditions; (b) actual consumer demand during DD conditions; and (c) the need to protect against the potential loss of a source of firm natural gas supply."

Xcel continued to treat 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 to reporting requirements established in the Commission's May 27, 2008; April 22, 2016; and February 12, 2020 *Orders* in Docket No. G002/M-08-46; Docket No. G002/M-16-88, and Docket No. G002/M-19-703, respectively.

[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.

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 3,968 customers between the 2019-2020 and 2020-2021 heating seasons in the Minnesota jurisdiction (from 465,382 to 469,350). The Company projected that this increase in customer base would increase the design-day requirements for Minnesota by 5,496 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 for the 2020-2021 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, which was a day for which only firm customers were on the system (See Attachment 1, Schedule 3, page 2 of 2). 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, unlike the Avg. Monthly DD method, 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 located.

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

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

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 2019-2020 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 used the 60 most recent months of data in its analysis),[5] and to the usage characteristics of customers in a given demand area.

The Company summarized 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, Xcel stated that 82% are greater than 0.80, 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 0.80 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 using a regression model based on daily consumption data would be very difficult due

[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 9, Xcel stated the following:

> The Avg. Monthly DD calculation is based on linear regression using 60 data points, from January 2015-December 2019, as shown on Attachment 1, Schedule 1, Pages 2-5. …
> .

the fact that it would require a forecast of daily interruptible load in order to isolate firm load. Further, Xcel's duel method approach counteracts some of the issues inherent in the Avg. Monthly DD method as the Avg. Monthly DD method generally results in higher forecasted requirements than those produced using the UPC DD method.

Xcel noted that some of the Company's SM COMM Models 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. As recommended in the Company's previous demand entitlement filings, Xcel did check and correct its regression models for autocorrelation and the Department appreciates Xcel doing so.

Xcel also noted that in three regression models, Fargo MN Residential, WBI Residential and Grand Forks MN Small Commercial, the analysis resulted in negative intercept coefficients which would indicate negative usage at zero Heating Degree Days (HDDs). The Company stated the following:[6]

> This would indicate negative gas use at 0 HDD, which is not realistically possible. To correct for this, we adjusted the heating degree day values to 0 for each summer month for the affected areas. This supports our base use of gas during the summer months, which is not temperature dependent, and is more reflective of reality. We then performed the regression analysis on the three areas, which resulted in positive intercept coefficients, though not statistically significant from zero.

The Department agrees with Xcel that negative usage at zero HDDs is impossible and appreciates Xcel's correction.

Thus, overall the Department concludes 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.

[6] See Petition's Attachment 1, pages 3-4 of 9.

3. Xcel's Forecasts

Xcel projected that its Minnesota and North Dakota design-day requirements will increase by 9,502 Dth/day to 858,750 Dth/day in the 2020-2021 heating season, or a 1.1% increase. The Company's forecast of its Minnesota design-day requirements is 749,192 Dth/day, an increase of 5,496 Dth/day, or an increase of 0.7%. In addition, the forecasted North Dakota usage for 2020-2021 is 109,559 Dth/day, an increase of 4006 Dth/day, or a 3.8% increase from the 2019-2020 heating season.

Xcel's customer forecast shows the number of Minnesota customers increasing by 3,968, from 465,382 in the 2019-2020 forecast to 469,350 in the 2020-2021 forecast, an increase of approximately 0.9%. The North Dakota customer count is forecasted to increase by approximately 3.9% to 60,014 in 2020-2021, up from 57,711 in 2019-20.

The Department notes that the bigger rate of increase in forecasted North Dakota gas consumption indicates that the proportion of design-day responsibility on the Xcel system shifted to North Dakota from Minnesota, which is typical of the trend in the past several years.[7] According to the *Petition*, the consumption allocator for Minnesota for the 2020-2021 heating season is 87.18%, down from 87.57% during the 2019-2020 heating season.

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 Petition 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, from 905,371 Dth/day to 908,042 Dth/day, or 0.3%.

1. Northern Natural Gas

The majority of Xcel's firm pipeline transportation contracts are with NNG. Most of these contracts were put in place in 2007 and ran through October 2017. As described in 2016-2017 filing, Xcel already renewed the long-term contacts for another 10-year term through October 2027 due to a required one-year advance notice for extension. As part of the extension, the renewal included a $0.01/Dth rate increase beginning November 1, 2017.

As described in the 2017-2018 filing, 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

[7] The exception was the Minnesota allocation increase from 87.51% to 87.57% for the 2019-2020 heating season (Docket No. G002/M-19-498).

in the Twin Cities were added, effective November 1, 2017.[8] As described in a previous filing, Xcel stated the following:[9]

> In addition, as NSP continues to look at long-term customer and design day forecasts we have contracted for additional entitlements on Northern's system to meet growing demand to be effective November 1, 2019. These expansions are part of NSP's discount agreement with Northern and will provide NSP with capacity to meet design day requirements. The costs will be reflected in next year's Contract Demand Entitlement filing.

In last year's filing, Xcel stated the following:[10]

> As discussed in the 2018-2019 Contract Demand Entitlement filing, NSP has contracted for incremental capacity on Northern's system as part of its Northern Lights 2019 project and existing contract rights, to be effective November 1, 2019 to meet growing demand. This expansion, for an additional 10,482 Dth/day on a year-round basis, is part of NSP's existing discount agreement with Northern, and provides NSP with capacity to meet design day requirements. Specifically, the incremental capacity provides for growth in the St. Cloud, MN area, as well as the Twin Cities. The incremental capacity is priced at the existing substantial discount, and is in effect for the remainder of the contract term.

In the instant Petition, Xcel stated the following:[11]

> As part of Northern's Northern Lights 2021 expansion project, NSP has contracted to acquire an additional 9,459 Dth/day to be effective November 1, 2021 to meet growing demand. Of this quantity, 3,600 Dth/day on a year-round basis, is significantly discounted as part of NSP's existing discount agreement with Northern, and provides for growth in the St. Cloud area. The remaining 5,859 Dth/day is at Northern's maximum tariff rate and will serve new growth areas on NSP's system and will provide NSP with capacity to meet future design day requirements. The discounted capacity will be provided through the remaining term of NSP's discount agreements. The tariff rate portion will be for a term of 10 years from November 1, 2021. Annual costs are expected to be $1.14 million per year and will be included in next year's filing.

[8] Docket G002/M-17-586 - Petition Attachment 1, page 4.
[9] Docket No. G002/M-18-528 Petition Attachment 1, page 5 of 8.
[10] Docket No. G002/M-19-498 Petition Attachment 1, page 5 of 10.
[11] See Petition Attachment 1, pages 4-8 of 9.

The additional entitlements that Xcel has described above are part of Northern's "Northern Lights 2021" expansion that is currently underway in Federal Energy Regulatory Commission (FERC) Docket No. CP20-503-000. In NNG's July 31, 2020 filing in the FERC Docket, NNG stated the following:[12]

> … Northern received requests in the Northern Lights 2021 Open Season from CenterPoint, Xcel and Midwest Natural Gas for 45,693 Dth/day for service commencing November 1, 2021, for incremental residential, commercial and industrial end users within Minnesota and Wisconsin[9]. [Footnote omitted.]
> … Northern has binding commitments for firm throughput service with three shippers for service commencing November 1, 2021. These commitments total an aggregated incremental peak winter entitlement of 45,693 Dth/day. … The following table summarizes the individual shippers and their winter peak day firm entitlement. (See Table below).

Shipper	Winter Dth/day
CenterPoint Energy Resources Corporation	34,880
Northern States Power Company, a Minnesota Corporation	9,459
Midwest Natural Gas	1,354

Given that the above Northern changes do not impact the instant Petition, the Department expects that Xcel in its next demand entitlement petition will provide not only the detailed costs to Xcel of the "Northern Lights 2021" project described above but also a detailed description of the incremental annual and/or winter peak-day capacity that Xcel has contracted with NNG.

In the instant Petition, Xcel stated the following:[13]

> FERC initiated a Section 5 (complaint) rate proceeding against Northern on January 16, 2019 (RP19-59), stating that Northern may be over-recovering its cost of service. In response, on July 1, Northern filed a Section 4 rate case (RP19-1353) proposing a 91% rate increase to the Market Area, including NSP's service territory, effective August 1, 2019.

[12] See NNG's July 31, 2020 Petition in Docket No. CP20-503-000 at FERC – pages 7 and 25.
[13] See Petition Attachment 1, page 7 of 9.

> … On May 18, Northern, NSP, other customers, and FERC Staff reached a settlement in principle, which results in an increase in market area rates of 28 percent from the pre-January 1 rates. The settlement rates reflect a 63 percent reduction from Northern's proposed rates and save NSP's customers approximately $9.2 million per year over Northern's originally filed rates as a result. The Settlement Agreement was filed with FERC on June 19, and an order addressing the settlement is expected in the fall of 2020.

The Department has previously addressed the impact of the above Northern rate case in its October 3, 2019 Comments and April 15,2020 Response Comments in last year's demand entitlement filing in Docket No. G002/M-19-498. The above Northern changes impact the instant Petition, and are a large part of the decrease in Minnesota jurisdiction demand related costs of approximately $5,287,928.

2. Viking Gas Transmission

The Company also made two adjustments to demand entitlements needed to serve peak demand on its VGT pipeline. Xcel stated that it renewed one Viking firm capacity entitlements of 1,500 Dth/day, that expires on October 31, 2020 at the same terms for an additional one-year term. Over the past several years, Xcel has purchased short-term capacity on Viking. The Company stated that "favorable spot market price differential between Emerson and Chicago City Gates, have resulted in higher than normal demand on Viking." Xcel for the 2020-2021 heating season stated that "NSP plans to acquire 13,761 Dth/day of delivered supply from a producer/marketer of Viking capacity for December through February, to meet seasonal peaking needs. NSP has already secured 5,000 Dth/day of this requirement and will look to complete the remaining acquisition before the winter season."[14]

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 would not own the pipeline capacity and the third party's pipeline cost will be imbedded in the commodity cost to form a delivered price. Therefore, Xcel will provide an update or supplement to its Petition in November 2020 that shows the final pipeline and supply entitlements for the 2020-2021 heating season.

Xcel stated the following:[15]

> On June 28, 2019 Viking filed with the FERC a general Section 4 rate case (RP19-1340) to change rates effective August 1, 2019 in accordance with its previous rate case settlement. Viking proposed an average seven percent rate increase to the rates for NSP. On July 10, NSP filed a protest requesting the proposed rates be suspended for the maximum five-

[14] Petition at Attachment 1, page 5 of 9.
[15] Petition at Attachment 1, pages 7-8 of 9.

> months, implemented thereafter subject to refund, and set for hearing. Following several settlement conferences between Viking, NSP, other customers, and FERC Staff, a Settlement was reached which reduces the maximum tariff rate below the previously effective tariff rate by approximately 12 percent. Viking filed to implement the settlement rates on February 14, 2020, subject to refund pending the approval of the Settlement Agreement. The formal settlement agreement was filed with FERC on February 28, 2020 and approved on July 1, 2020.
>
> The Settlement rates provide NSP customers annual savings of approximately $1.77 million from Viking's filed rates and are included in the instant filing.

The Department has previously addressed the impact of the above Viking rate case in its October 3, 2019 Comments and April 15,2020 Response Comments in last year's demand entitlement filing in Docket No. G002/M-19-498. The above Viking changes impact the instant Petition, and contribute to the decrease in Minnesota jurisdiction demand related costs of approximately $5,287,928.

3. Great Lakes Gas Transmission

Xcel had one change to its Great Lakes firm capacity entitlements resulting in no change to contract quantity. Xcel stated that it "extended two Great Lakes firm transportation agreements for additional two-year terms effective April 1, 2021 at the same terms as the original agreements." The Company stated that the GLGT capacity supports withdrawal and summer injection of ANR storage quantities in addition to supporting its Northern capacity.[16] In its June 22, 2020 filing in FERC Docket No. CP20-485-000, GLGT stated the following:[17]

> GLGT hereby submits an abbreviated application ("Application") for authorization to abandon firm capacity by a lease agreement with ANR Pipeline Company ("ANR"). This application is related to an application filed by ANR on June 22, 2020, in Docket No. CP20-484-000, for the authorizations necessary to construct, own, and operate the Alberta XPress Project ("Project" or "AXP Project"), including the authorization to acquire firm capacity from GLGT pursuant to the capacity lease agreement between GLGT and ANR dated June 19, 2020 ("Lease Agreement"). To accommodate the needs of GLGT and ANR AXP Project Shippers, GLGT respectfully requests that the Commission issue an order approving this Application contemporaneously with any order approving ANR's

[16] Petition Attachment 1, Schedule 5 and Attachment 1 pages 5-6 of 9.
[17] See GLGT's June 22, 2020 Petition in Docket No. CP20-485-000 at FERC – page 1-4.

> application for acquisition of the lease capacity in Docket No. CP20-484-000.
> … Lastly, the Lease Agreement does not adversely affect existing customers. The charges under the Lease Agreement will fully compensate GLGT for the leased capacity, and the Lease Agreement provides GLGT with the ability to provide service on existing capacity without subsidization by its existing customers. GLGT will not incur any additional construction costs to facilitate the Lease Agreement.

The Department requests that Xcel in its Reply Comments and/or in its supplement or November update briefly explain if the above-mentioned GLGT and below-mentioned ANR FERC dockets will impact Xcel and its firm customers.

4. ANR Pipeline

There was also a small reduction to capacity on the ANR Pipeline pursuant to the ANR Pipeline tariff. In its June 22, 2020 filing in FERC Docket No. CP20-484-000, ANR stated the following:[18]

> ANR Pipeline Company ("ANR") hereby submits for filing an abbreviated application ("Application") for a certificate of public convenience and necessity, requesting authorization to construct, own, and operate the Alberta XPress Project ("Project" or "AXP Project").
>
> … The Project will match this growing demand at several points on the ANR system[6] with low cost natural gas supply from multiple supply basins, including imports from Western Canadian supply. The proposed Project has been optimized using a mix of existing upstream capacity on the GLGT interstate pipeline system; existing ANR capacity; and expanded facilities on ANR's SEML, which together provide 165,000 Dth/d of incremental firm transportation capacity from the GLGT Emerson receipt point to delivery locations along the ANR system, with primary delivery points along ANR's SEML at Duralde and ANR's SE Headstation[7] ("SEHS"), a virtual pooling point located adjacent to the Eunice Compressor Station in Acadia Parish, Louisiana. The Project will also strengthen the reliability of the region's natural gas transportation infrastructure and available supply sources, in part by increasing throughput on ANR's pipeline system and enabling interconnected pipelines to deliver more gas into ANR's pipeline system. Additionally, the Project will provide the Project Shippers with a seamless service from GLGT to ANR from Emerson to Duralde and the SEHS, with access to secondary points on ANR's system, increasing the utilization of

[18] See ANR's June 22, 2020 Petition in Docket No. CP20-484-000 at FERC – page 1-4.

> the GLGT system. ANR has executed two binding precedent agreements with the Project Shippers to provide 140,000 Dth/d of firm transportation service for a 21-year primary term and 25,000 Dth/d of firm transportation service for an 11-year primary term, together representing 100% of the Project capacity. The total estimated cost for the Project facilities proposed herein is approximately $81.1 million. (Footnotes Omitted).

The Department requests that Xcel in its Reply Comments and/or in its supplement or November update briefly explain if the above-mentioned GLGT and ANR FERC docket(s) will impact Xcel and its firm customers.

5. ANR Storage Co (ANRS)

The Company stated that it had extended a service agreement with ANRS for two more years, effective April 1, 2021. The agreement allows for storage of gas supplies in Michigan. In addition, the Company stated the following:[19]

> This agreement allows for the storage of gas supplies in Michigan and provides cost effective method to meet our obligation to supply gas at the Carlton interconnect with Northern. In addition, the capacity provides regional supply diversity, and increased reliability of gas supplies during extreme cold events.

6. Conclusion

The Department has analyzed the above changes in design-day entitlement resources and each change appears reasonable at this time to serve firm customers on a peak day. The Department will provide its final conclusions and recommendations once Xcel has filed a supplement or update to its Petition in November 2020 that shows the final pipeline and supply entitlements for the 2020-2021 heating season.

C. PROPOSED RESERVE MARGIN

Xcel's proposed design-day reserve margin in Minnesota is 5.66% for 2020-2021, which is a slight decrease from the 6.61% figure in 2019-2020. 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 42,439 Dth/day, as shown in further

[19] Id.

detail in Department Attachment 1, is appropriate to meet its design-day needs.[20] Xcel has previously stated the following:[21]

> 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.
>
> 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 2020-2021 reserve margin is not unreasonable.

In general, the Department notes that it has previously provided a detailed discussion and update on the reserve margin discussion in its August 1, 2019 Supplemental Comments in Docket No. G002/M-18-528.

D. JURISDICTIONAL ALLOCATIONS

The 2020-2021 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 (748,632 Dth/day) by the same demand for the Company's system (858,751 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which decreased from 87.57% to 87.18%.[22]

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

[20] See Xcel's Petition at Attachment 1, page 8 of 9 and Attachment 1 Schedule 1 page 5.
[21] See Xcel's 8-1-2017 Petition in Docket No. G002/M-17-586 at Attachment 1, page 7 of 8.
[22] Petition Attachment 1, pages 6 and 7.

based and therefore change the allocation between the states. Again, such changes are typically not significant. The Department concludes that Xcel's proposed jurisdictional allocation change is reasonable.

E. SUPPLIER RESERVATION FEES

Xcel stated that its Supplier Reservation fees have changed. The resulting net change is an increase of $88,166 annually based on the proposed addition of 2,671 Dth/day year-over-year. Each of the supplier contracts is listed in the Trade Secret version of the Company's Petition. The Department will not comment on each individual contract but has reviewed the filings and can confirm that Xcel's proposal appears reasonable.[23]

F. XCEL'S PGA COST RECOVERY PROPOSAL

Xcel proposed to reflect the costs associated with the demand entitlements identified in the Petition in the PGA effective November 1, 2020. The demand entitlements in Xcel Attachment 2, Schedule 2, Page 1 of 4, represent the demand entitlements for which the Company's firm customers will pay. Attachment 2 Schedule 2 of the Petition compares the July 2020 PGA costs to the currently proposed November 2020 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 $0.0443/Dth, or approximately $3.85 more annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand costs increase by $0.0472/Dth, or approximately $13.41 more annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand costs increase of $0.0436/Dth, or approximately $63.77 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 at this time and recommends that Xcel in its supplement update its comparison to the October PGA rather than the July PGA.

[23] See Xcel's Petition at Attachment 1, page 8 of 9 and Attachment 1, Schedule 2, page 1.

III. CONCLUSIONS AND RECOMMENDATIONS

In Reply Comments or November supplement or update, the Department requests that Xcel briefly explain if the above-mentioned GLGT and ANR FERC docket(s) will impact Xcel and its firm customers.

The Department will file its final recommendations after the Company's November 2020 supplement or update to its demand entitlement proposal.

/ar

Department Attachment 1
Docket No. G002/M-20-633
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)
2020-2021**	469,350	3,968	0.85%	749,192	5,496	0.74%	791,631	(1,202)	-0.15%	42,439	5.66%
2019-2020**	465,382	4,304	0.93%	743,696	7,955	1.08%	792,833	12,969	1.66%	49,137	6.61%
2018-2019**	461,078	3,309	0.72%	735,741	5,594	0.77%	779,864	3,566	0.46%	44,123	6.00%
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	798	0.10%	44,674	6.23%
2014-2015**	446,409	4,836	1.10%	715,945	9,010	1.27%	761,354	12,029	1.61%	45,409	6.34%
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:			0.95%			1.18%			1.18%		5.76%

	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)
2020-2021**	NA			0.0904	1.5962	1.6867	NA
2019-2020**	738,210	2,388	0.32%	0.1056	1.5980	1.7036	1.5862
2018-2019**	735,822	(9,309)	-1.25%	0.0957	1.5957	1.6914	1.5959
2017-2018**	745,131	11,420	1.56%	0.1008	1.5950	1.6958	1.6277
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%	0.1017	1.6038	1.7055	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			2.00%	0.0915	1.5878	1.6793	1.4743

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

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Comments

Docket No. G002/M-20-633

Dated this **29th** day of **October 2020**

/s/Sharon Ferguson

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