MINNESOTA DEPARTMENT OF COMMERCE

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September 28, 2016 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-16-649

Dear Mr. Wolf:

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

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

The petition was filed on August 1, 2016. The petitioner on behalf of Xcel is:

Amy A. Liberkowski
Director, Regulatory Pricing & Analysis
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

The Department recommends that the Commission:

- approve Xcel's proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2016 supplemental filing;
- allow Xcel to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2016 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2016;
- approve changes in the jurisdictional allocation for demand costs.

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

Sincerely,

/s/ MICHAEL RYAN
Rates Analyst

MR/ja
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

DOCKET NO. G002/M-16-649

I. SUMMARY OF XCEL'S REQUEST

Northern States Power Company (Xcel or the Company) filed a demand entitlement petition (*Petition*) on August 1, 2016, 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, 2016. The Company stated that, in the event that the Commission does not act by November 1, 2016, 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, 2016, 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 2016-2017 effective November 1, 2016. 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 7,747 dekatherms per day (Dth/day), about 1.08 percent (7,747 Dth/717,478 Dth);
- change the capacity resources used to meet the design-day requirements and increase the amount of capacity resources (total entitlements) for Minnesota by 26,964 Dth/day or 3.65 percent (26,964 Dth/738,570 Dth);

[1] The entitlement levels discussed in Xcel's filing are for the total Minnesota Company which encompasses the combined entitlements for Xcel's Minnesota and North Dakota jurisdictions. Minnesota's portion of the entitlements is the total combined entitlements times the Minnesota allocation factor discussed below. The Department has included Department Attachment 4, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

- with these changes in Minnesota's need and resources, the reserve margin increases from 2.9 percent to 5.6 percent for Minnesota[2];
- slightly decrease the jurisdictional allocation to Minnesota (rather than North Dakota) to 87.98 percent from 87.99 percent to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

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

Table 1: Proposed Changes in Entitlements for Xcel 2016-2017

Type of Entitlement	Proposed Dth Change	Rate	Months	Proposed Cost Change
NNG TFX (Nov-Mar)	1,539	$8.6272	5	$66,386.30
NNG TFX (Apr-Oct)	1,539	$4.0000	7	$43,092.00
VGT FT-A (Dec-Feb)	(12,428)	$4.7507	3	$(177,125.10)
VGT FT-A (Nov-Mar)	16,371	$4.7507	5	$388,868.55
ANR FSS (Jan-Dec)	(44)	$1.7820	12	$(940.90)
ANR FSS (Jan-Dec)	(15,300)	$1.7820	12	$(327,175.20)
ANR FSS (Jan-Dec)	15,300	$0.6801	12	$124,866.36
ANR FTS (Jan-Dec)	(4,829)	$9.4000	12	$(544,711.20)
ANR FTS (Jan-Dec)	4,829	$22.5453	12	$1,306,455.04
ANR FTS (Nov-Mar)	(15,171)	$4.4000	5	$(333,762.00)
ANR FTS (Nov-Mar)	15,171	$8.0342	5	$609,434.24
ANR FTS (Apr-Oct)	(4,935)	$4.4000	7	$(151,998.00)
ANR FTS (Apr-Oct)	4,935	$8.0342	7	$277,541.44
Total for Change in Pipeline Entitlement				**$ 1,280,931.54**

As indicated in the table above, Xcel proposed a number of changes in its demand entitlements that would increase costs from all source systems by approximately $1,280,931.54. This amount is for Minnesota and North Dakota customers. As discussed further below, the increases are related to various reliability needs across the Xcel system.

The Company's largest increase to its net supply entitlement is largely driven by the Sibley Propane Plant which had limited output in 2015-2016 heating season, but is expected to be

[2] Xcel initially set a reserve margin for the 2015-2016 heating season at 6.2% in Docket No. G002/M-15-727; however, in Xcel's October 30, 2015 Supplemental Comments the Company stated that the Sibley Propane Plant would have limited reliable output above 19,200 Dth/day. This limitation was a reduction from the original design day assumption that the plant would provide 46,000 Dth/day of peak shaving capacity. The Company explored additional capacity options with Northern Natural Gas (NNG), but NNG did not have any open capacity to serve the system where the propane plant is located. As a result, Xcel reduced its reserve margin to 2.9%.

operational in the upcoming winter season. The Company also proposed increased supply entitlements from Northern Natural Gas (NNG or Northern) and Viking Gas Transmission Company (VGT) while renewing entitlements from ANR Pipeline and a slight decrease in storage entitlement from ANR Storage Company. The net change is an increase of 30,743 Dth/day in total (26,964 Dth/day for Xcel's Minnesota jurisdiction). Xcel noted that there is an increase in the reserve margin – from 2.9 percent to 5.6 percent – due to the Sibley Propane Plant availability, and that an increase in entitlements is needed in order to meet increased design-day consumption in the most economical manner and to raise the reserve margin back to previously targeted levels.

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.[3] Xcel provided a summary of hedging transactions in place for the 2014-2015 heating season in response reporting requirements established in the Commission's May 27, 2008 and April 22, 2016 *Orders* in Docket No. G002/M-08-46 and Docket No. G002/M-16-88, respectively.

II. DEPARTMENT'S ANLAYSIS OF XCEL'S REQUEST

The Department's analysis of the Company's request includes a description and an evaluation of the Company's *Petition*. The Department discusses each part of the Company's request below.

A. XCEL'S PROPOSED DESIGN-DAY LEVELS

1. Xcel's Customer Base

Xcel expects an increase of 3,814 customers between the 2015-2016 and 2016-2017 heating seasons in the Minnesota jurisdiction (from 450,444 to 454,258). The Company projected that this increase in customer base would increase the Design Day (DD) requirements for Minnesota by 7,747 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 2016-2017 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.

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[3] 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, the coldest day in recent years.[4] Xcel multiplied the 1.57393 Dth/day value by estimates of total firm customers in all of Xcel's service areas and added the contracted billing demand for Small and Large Demand Billed Customers to arrive at the total expected design-day demand for the Xcel system. Thus, the way customers are distributed among service areas does not affect the aggregate forecasts produced by the UPC DD method because the total number of customers and the resulting total volume is unchanged no matter where the customers are assigned.

If either cold temperatures or differences 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.[5] These separate demand areas have their own specific usage characteristics based on the input data; as such, the coefficients used to estimate use per customer vary from service area to service area. Consequently, the shifting of customers among demand areas can affect the aggregate forecasts produced by the Avg. Monthly DD method. The Company's service areas were unchanged from the 2015-2016 heating season to the 2016-2017 heating season; therefore, any changes in the aggregate forecast numbers using the Avg. Monthly DD method are related to typical growth dynamics and data turnover (Xcel uses the 60 most recent months of data in its analysis), and to the usage characteristics of customers in a given demand area.

The Company summarizes its output statistics for each of its demand areas in Attachment 1, Schedule 1, of its *Petition*. Of the R-squared values for its various statistical models, 70% are greater than 0.95, 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 0.95 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

[4]The Department notes that, while January 2014 was the coldest month in recent years, for design day purposes only the coldest single day is important. None of the days during January 2014 had temperatures as low as the January 29, 2004 low temperature.

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

customers will inherently increase data variability because changes in consumption by a single customer, or group of customers will have a much greater impact on total consumption than an estimation group that has a larger number of customers.

The statistics presented by the Company in its *Petition* suggests that the Avg. Monthly DD method produces acceptable forecasts. In Docket No. G002/M-13-663 the Department noted that, while acceptable, the Avg. Monthly DD method might not represent the best option available for forecasting natural gas needs. The Department noted that there were potential issues related to the model 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. Thus the Department believes that Xcel's forecast methodology is reasonable and the Department agrees with Xcel that the Company should continue to use the two methods to develop its design-day estimate, updating the UPC DD method when appropriate.

3. Xcel's Forecasts

Xcel projected that its (Minnesota and North Dakota) design-day requirements will increase by 8,819 Dth/day to 824,269 Dth/day in the 2016-2017 heating season, or a 1.1 percent increase. The Company's forecast of its Minnesota design-day requirements is 725,225 Dth/day, an increase of 7,747 Dth/day, or an increase of 1.1 percent. In addition, the forecasted North Dakota usage for 2016-2017 is 99,044 Dth/day, an increase of 1,071 Dth/day, or a 1.1% increase from the 2015-2016 heating season.

Xcel's customer forecast shows the number of Minnesota customers increasing by 3,814, from 450,444 in the 2015-2016 forecast to 454,258 in the 2016-2017 forecast, an increase of approximately 0.8 percent. The North Dakota customer count is forecasted to increase by approximately 2.9 percent to 55,035 in 2016-2017, up from 53,490 in 2015-2016.

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 2016-2017 heating season is 87.98 percent, down from 87.99 percent during the 2015-2016 heating season. The higher overall economic growth rates in North Dakota, relative to Minnesota, has been on-going and has led to incremental decreases in the allocator factor over the past few years.

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

B. PROPOSED CHANGED IN XCEL ENERGY'S DESIGN-DAY RESOURCES

Xcel's filing proposed changes in the resources used to meet its design-day customer requirements. Overall, the Company's system firm supply entitlements, which include entitlements for Minnesota and North Dakota, rose slightly, from 866,180 Dth/day to 870,123 Dth/day, or 0.45 percent.

1. Northern Natural Gas

The majority of Xcel's firm pipeline transportation contracts are with Northern. Most of these contracts were put in place in 2007 and run through October 2017. MERC has noted in the petition that the long-term contacts have been renewed 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. The Company made one change to its Northern entitlements for its 2016-2017 heating season that serve peak demand. According to the Company, the change relates to the addition of 1,539 Dth/day of incremental capacity at St. Cloud, MN.[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 the Company plans to purchase 16,371 Dth/day of capacity for this winter as is consistent with its practices over the last several years. The planned amount replaces 12,428 Dth/day that was planned for 2015-2016 or a net increase of 3,943 Dth/day of Viking capacity. This capacity is available to serve the Grand Forks/East Grand Forks area, and the Minneapolis/St. Paul metro area throughout the winter.[7] The Department followed up with the Company to discuss the rationale of increasing the Viking contract from a 3-month term to a 5-month term. Xcel stated that due to market conditions and competition for Viking capacity, the pipeline indicated that the Company would likely have to purchase the capacity for greater than last year's 3-month term. The Company also indicated that since the filing of the docket on August 1st, the contract has been obtained. In order to ensure that the Company received the capacity, Xcel increased to a 6-month term for 16,371 Dth/day. The Company will reflect this change in the supplemental filing due in November.[8]

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

3. *Great Lakes Gas Transmission*

Xcel renewed two Great Lakes firm capacity entitlements totaling 9,248 Dth/day of winter-only capacity for two years. The Company also renewed 895 Dth/day of summer capacity to support the withdrawal and summer injection of ANR storage quantities. [9]

4. *ANR Pipeline*

As shown in Table 2 below, there is substantial year-over-year increase in ANR capacity cost even though no new capacity is being added. Based on follow up with the Company, the increase is entirely due to ANR's pending rate case with the Federal Energy Regulatory Commission (FERC). The filed rates are set to take effect August 1, 2016, subject to the pending rate case.

Table 2: Proposed Changes in ANR Entitlements for Xcel 2016-2017

Type of Entitlement	Proposed Dth Change	Rate	Months	Proposed Cost Change
ANR FSS (Jan-Dec)	(44)	$1.7820	12	$(940.90)
ANR FSS (Jan-Dec)	(15,300)	$1.7820	12	$(327,175.20)
ANR FSS (Jan-Dec)	15,300	$0.6801	12	$124,866.36
ANR FTS (Jan-Dec)	(4,829)	$9.4000	12	$(544,711.20)
ANR FTS (Jan-Dec)	4,829	$22.5453	12	$1,306,455.04
ANR FTS (Nov-Mar)	(15,171)	$4.4000	5	$(333,762.00)
ANR FTS (Nov-Mar)	15,171	$8.0342	5	$609,434.24
ANR FTS (Apr-Oct)	(4,935)	$4.4000	7	$(151,998.00)
ANR FTS (Apr-Oct)	4,935	$8.0342	7	$277,541.44
Total for Change in Pipeline Entitlement				**$ 959,709.79**

Xcel indicated that they are an intervening party in the rate case and that an Agreement of Principal has been reached on settlement terms. The settlement is expected to lower the cost increase shown in Table 2. Subject to FERC approval, Xcel has indicated that the lower cost increase will be included in the November supplemental filing.[10]

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 2016-2017 demand entitlements

[9] *Petition* Attachment 1, pages 5.
[10] DOC Attachment 2.

appear to be reasonable, and looks forward to reviewing the updated information that will be included in the Company's November supplemental filing.

C. CHANGE IN XCEL'S RESERVE MARGIN

Xcel's proposed design-day reserve margin in Minnesota is 5.6 percent for 2016-2017, which is an increase from the 2.9 percent figure in 2015-2016. But it is important to remember that the Company initially set a reserve margin for the 2015-2016 heating season at 6.2% in Docket No. G002/M-15-727, which was subsequently reduced due to the limited reliable output of the Sibley Propane Plant. This output limitation was a reduction from the original design day assumption that the plant would provide 46,000 Dth/day of peak-shaving capacity. The Company explored additional capacity options with NNG, but NNG did not have any open capacity to serve the system where the propane plant is located.

The reserve margin balances protecting against the loss of a firm gas-supply source and actual consumer demand under design-day conditions, with the likelihood of experiencing design-day conditions. Xcel stated that its proposed reserve margin of 45,854 Dth/day, of which 40,309 Dth/day is for the Minnesota jurisdiction, is appropriate to meet its design-day needs. 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 2016-2017 reserve margin is not unreasonable.

D. CHANGES IN XCEL'S JURISDICTIONAL ALLOCATIONS

The 2016-2017 heating season jurisdictional allocation factor, which is used to allocate new peak capacity to Minnesota and North Dakota, remained within 0.01 percent of the projection for the prior heating season. The allocation factor is calculated by dividing the design-day forecasted demand for Minnesota (725,225 Dth/day) by the same demand for the Company's system (824,269 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which fell from 87.99 percent to 87.98 percent.[11]

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

[11] *Petition* Attachment 1, page 6.

E. CHANGES IN XCEL'S SUPPLIER RESERVATION FEES

Xcel stated that its Supplier Reservation fees have changed. The resulting net change is a decrease of $221,249.50 annually. [TRADE SECRET DATA HAS BEEN EXCISED]. The new total expense level reflects these changes. Therefore, the Department concludes that Xcel's proposal is reasonable.[12]

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, 2016. The demand entitlements in Xcel Trade Secret Attachment 2, Schedule 1, Page 1 of 2, represent the demand entitlements for which the Company's firm customers will pay. Department Attachment 4 compares the July 2016 PGA costs to the anticipated November 2016 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 $0.0107/Dth, or approximately $0.93 more annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand costs increase by $0.0029/Dth, or approximately $0.82 more annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand costs increase of $0.0184/Dth, or approximately $26.91 more annually, for the average Large Commercial customer consuming 1463 Dth annually; and
- No Change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers. These customer classes are not allocated demand costs under the current cost allocation plan.

Based on its review, the Department concludes that the Company's proposal appears to be reasonable. The Department is aware that minor changes in cost and entitlement levels may occur between the filing of these *Comments* and November, 1, 2016. As such, the Department recommends that the Company provide a supplemental filing on November 1, 2016 detailing final demand entitlement levels and costs, particularly in light of the ANR Pipeline rate case.

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[12] *Petition* Attachment 1, Schedule 2, page 1.

III. CONCLUSIONS AND RECOMMENDATIONS

The Department recommends that the Commission:

- approve Xcel's proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2016 supplemental filing;
- allow Xcel to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2016 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2016; and
- approve changes in the jurisdictional allocation for demand costs.

/ja

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☒ Public Document

Xcel Energy			
Docket No.:	G002/M-16-649		
Response To:	MN Department of Commerce	Informal Information Request No.	1
Requestor:	Michael Ryan		
Date Received:	August 25, 2016		

Question:

Reference: Viking transportation entitlement (Att. 1, Schedule 2, pg. 1):

- Xcel increased Viking contract from 3 to 5 months according to the calculation (the label for the new contract shows Dec-Feb). Can you confirm that it is indeed for the 5-month term?
- Why was the Viking contract increased to 5 months (e.g. insufficient shoulder month capacity)?

Response:

The referenced Viking contract is actually for six months. While preparing our winter plans, we projected a need for a three month contract. However, recent market conditions on Viking – largely a significant spot gas price differential between Emerson and Marshfield, WI –resulted in an increase in demand for capacity on the pipeline. As such, Viking indicated that there were other shippers interested in the remaining unsold capacity and that we would likely need to purchase a five-month contract to obtain the capacity. At that time, we submitted our Contract Demand Entitlement filing to the MPUC with costs reflecting the expected five-month term.

Subsequently, Viking placed our five-month contract out for competitive bidding pursuant to its tariff. Another potential shipper submitted a bid to Viking for a six-month contract (thus exceeding our offer of a five-month contract on a net present value basis). Viking advised that they had no other capacity available for this winter and that we should match the six-month bid or risk going without capacity for this winter. As we needed the capacity to meet our design day needs for this winter, we agreed to the six-month term and obtained the contract.

The additional month of capacity costs will be reflected in our supplemental filing at the beginning of November.

Preparer:	Richard Derryberry
Title:	Manager
Department:	Gas Resource Planning
Telephone:	303-571-7104
Date:	September 6, 2016

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy		
Docket No.:	G002/M-16-649	
Response To:	MN Department of Commerce	Informal Information Request No. 2
Requestor:	Michael Ryan	
Date Received:	August 25, 2016	

Question:

Reference: ANR transportation entitlement (Att. 1, Schedule 2, pg. 1):

- Can you expand on the reasoning for why ANR transport increased so much year over year?
- ANR is less transparent than other pipelines and it hard to verify ANR pricing with ratchets against the posted rates on the ANR website. What drove the increase in the contracts? Can you provide additional clarification and the breakout of pricing?
- It appears that the ANR transportation contracts that increased are short term contracts. Will the company be exploring other options once the contracts expire? Can you provide what the options might be?

Response:

The year-over-year increase in transportation costs on ANR Pipeline, reflected in our Contract Demand Entitlement filing is due to a Rate Case proceeding pending at the Federal Energy Regulatory Commission (FERC), where we are an active participant in the case. The filed rates were set to take effect August 1, 2016, subject to refund pending the outcome of the case. ANR proposed an average 86% increase in their various applicable rates purportedly to cover the capital costs of numerous projects to replace or upgrade numerous system facilities. Our year-over-year cost increase on ANR is entirely due to ANR's proposed transportation rate increase offset by a smaller decrease in storage rates as shown on the table below.

		Dth	Previous Rate	Filed Rate	Annual Cost Difference
106209	FTS-1	4,829	$ 9.4000	$22.5453	$ 761,744
106211 (Winter)	FTS-1	15,171	$ 4.4000	$ 8.0342	$ 275,672
106211 (Summer)	FTS-1	4,935	$ 4.4000	$ 8.0342	$ 125,543
114492	FTS-1	66,500	$ 5.3660	$ 5.3660	$ -
106212	FSS	15,300	$ 1.7820	$ 0.6801	$ (202,308.84)
				Total:	**$ 960,651**

Ratchets on ANR apply to storage services and provide injection/withdrawal capacity that decreases as the quantity stored declines. NSP's ANR storage contract is for seasonal service with ratchets to allow us to match our storage to the winter days where it is most needed.

ANR's proposed rate increases apply both to short-term and long-term contracts. However, our long-term contract (114492) is based on an incremental, system-expansion rate, that is unaffected by ANR's proposed rate increases. The transportation agreements on ANR provide the company with additional regional diversity and transportation flexibility. The storage also provides potential price protection from gas price spikes. It is our policy to evaluate all reasonable options for providing reliable, regionally diverse gas service at reasonable cost when entering into new or amended service agreements.

In the intervening time since the submittal of our Contract Demand Entitlement filing, ANR and the intervening parties (including Xcel Energy - Northern States Power) reached an Agreement in Principle on settlement terms. The settlement is expected to significantly lower our projected cost increase. A settlement document is being drafted to memorialize those terms, which will then be submitted to FERC for approval. Pending the outcome of the settlement, ANR filed to move into effect lower rates to substitute for the higher rates originally proposed. If these settlement rates are approved by FERC, the lower cost increase will be reflected in our November supplemental filing.

Xcel Energy offers to provide further information on the ANR rate case settlement by phone or in person if the Department would find further discussion helpful.

Preparer: Richard Derryberry
Title: Manager
Department: Gas Resource Planning
Telephone: 303-571-7104
Date: September 6, 2016

Docket No. G002/M-16-649
Demand Entitlement Analysis-Minnesota Jurisdiction

Northern States Power Company d/b/a Xcel Energy

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
Heating Season	(1) Number of Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Dth)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Design-Day Capacity (Dth)	(8) Change from Previous Year	(9) % Change From Previous Year	(10) Reserve Margin	(11) % of Reserve [(7)-(4)]/(4)
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:			0.99%			1.29%			1.27%		5.62%

	Firm Peak-Day Sendout						
Heating Season	(12) Firm Peak-Day Sendout (Dth)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess per Customer [(7) - (4)]/(1)	(16) Design Day per Customer (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak-Day Send per Customer (12)/(1)
2016-2017**	NA			0.0887	1.5960	1.6847	NA
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			2.41%	0.0890	1.5856	1.6746	1.4366

*-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

Docket No. G002/M-16-649

Demand Entitlement--PGA Cost Recovery Analysis

Residential	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July (7/1/16)	Nov 2016 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.5042	$2.8402	$2.8137	$3.1517	-42.74%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.9008	$0.8220	$0.8327	$0.8434	-6.37%	2.60%	1.28%	$0.0107
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.5213	$5.5055	$5.8542	-29.16%	6.03%	6.33%	$0.3487
Average Annual Usage (Dk)	87	87	87	87				
Average Annual Total Cost	$718.60	$480.10	$478.72	$509.05	-29.16%	6.03%	6.33%	$30.32
Average Annual Total Demand Cost of Gas	$78.33	$71.48	$72.41	$73.34			**Current Allocation**	**$0.93**

Small Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July (7/1/16)	Nov 2016 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4871	$2.8402	$2.8137	$3.1517	-42.56%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.8984	$0.8254	$0.8361	$0.8390	-6.61%	1.65%	0.35%	$0.0029
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.8987	$4.8829	$5.2238	-31.43%	6.64%	6.98%	$0.3409
Average Annual Usage (Dk)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,391.35	$1,386.87	$1,483.69	-31.43%	6.64%	6.98%	$96.82
Average Annual Total Demand Cost of Gas	$255.17	$234.43	$237.47	$238.30			**Current Allocation**	**$0.82**

Large Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July (7/1/16)	Nov 2016 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4871	$2.8402	$2.8137	$3.1517	-42.56%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.8917	$0.8099	$0.8206	$0.8390	-5.91%	3.59%	2.24%	$0.0184
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.8816	$4.8658	$5.2222	-31.38%	6.98%	7.32%	$0.3564
Average Annual Usage (Dk)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,140.04	$7,116.93	$7,638.21	-31.38%	6.98%	7.32%	$521.28
Average Annual Total Demand Cost of Gas	$1,304.24	$1,184.59	$1,200.24	$1,227.15			**Current Allocation**	**$26.91**

Small Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July (7/1/16)	Nov 2016 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4926	$2.8402	$2.8137	$3.1517	-42.62%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	NA	NA	NA	$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9635	$0.9635	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.8037	$3.7772	$4.1152	-36.26%	8.19%	8.95%	$0.3380
Average Annual Usage (Dk)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,235.93	$30,186.48	$29,976.18	$32,658.54	-36.26%	8.19%	8.95%	$2,682.37
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00			**Current Allocation**	**$0.00**

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Demand Entitlement--PGA Cost Recovery Analysis

Medium Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-15-727)	Last Month PGA: July (7/1/16)	Nov 2016 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4696	$2.8402	$2.8137	$3.1517	-42.38%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	NA	NA	NA	$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4751	$0.4751	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$3.3153	$3.2888	$3.6268	-38.99%	9.40%	10.28%	$0.3380
Average Annual Usage (Dk)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,676.89	$214,531.04	$212,816.25	$234,687.90	-38.99%	9.40%	10.28%	$21,871.64
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-15-727)	Last Month PGA: July (7/1/16)	Nov 2016 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.5501	$2.8402	$2.8137	$3.1517	-43.21%	10.97%	12.01%	$0.3380
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	NA	NA	NA	$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4346	$0.4346	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9847	$3.2748	$3.2483	$3.5863	-40.08%	9.51%	10.41%	$0.3380
Average Annual Usage (Dk)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,464,438.14	$2,442,939.49	$2,423,171.05	$2,675,311.95	-40.08%	9.51%	10.41%	$252,140.90
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00			**Current Allocation**	**$0.00**

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

Current Allocation Summary Change from most recent PGA Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.3380	12.01%	$0.0107	1.28%	$0.93	$30.32	6.33%
Small Commercial	$0.3380	12.01%	$0.0029	0.35%	$0.82	$96.82	6.98%
Large Commercial	$0.3380	12.01%	$0.0184	2.24%	$26.91	$521.28	7.32%
Small Interruptible	$0.3380	12.01%	$0.0000	NA	$0.00	$2,682.37	8.95%
Medium Interruptible	$0.3380	12.01%	$0.0000	NA	$0.00	$21,871.64	10.28%
Large Interruptible	$0.3380	12.01%	$0.0000	NA	$0.00	$252,140.90	10.41%

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public Comments

Docket No. G002/M-16-649

Dated this 28th day of September 2016

/s/Sharon Ferguson

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