COMMERCE DEPARTMENT

February 25, 2021

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-20-633

Dear Mr. Seuffert:

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

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

These Supplemental Comments are in response to Xcel's Supplemental Filing filed on October 29, 2020 and Reply Comments filed on November 9, 2020. The petitioner on behalf of Xcel is:

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

The Department recommends that the Minnesota Public Utilities Commission (Commission) accept the Company's proposed level of demand entitlements and allow Xcel to recover the associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2020. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ja
Attachment

Before the Minnesota Public Utilities Commission

Supplemental Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G002/M-20-633

I. INTRODUCTION

Northern States Power Company (NSP, Xcel, or the Company) filed a demand entitlement petition (Petition) on July 31, 2020, with the Minnesota Public Utilities Commission (Commission). On October 29, 2020 the Minnesota Department of Commerce, Division of Energy Resources (Department) filed Comments in response to the Company's Petition. In its Comments, the Department stated that it would provide its final recommendations to the Commission after the Company filed its update or supplement on November 2, 2020.

On October 29, 2020, the Company filed its *Supplemental Filing* which showed the final demand entitlement volumes and costs that would be charged to ratepayers. The Company noted that there were changes to the firm transport entitlement levels, a change in design day and a cost change since the original July 31, 2020 Petition.

On November 9, 2020, the Company filed its *Reply Comments* providing responses to the Department's Comments and an update on a pipeline refund.

In its Petition, Xcel indicated that it "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."[1] In its *Supplemental Filing*, Xcel stated that, due to market conditions, Viking capacity was sold out for full-path transportation. Instead, the Company acquired an additional delivered supply agreement for 8,700 Dth per day of capacity, for a total of 13,700 Dth/day; approximately 29 Dth per day more than it had originally intended to procure. In its *Supplemental Filing*, the Company stated the following:

> In the Petition, the Company inadvertently listed the wrong rate for one previously acquired delivered supply agreement to meet design day requirements. We have corrected this rate in **Attachment 1, Schedule 2, Pages 1-2**. The change to properly reflect the rate increases the overall costs by $27,000.

[1] Petition at Attachment 1, page 5 of 9. There is a typographical error in the statement. The initial acquisition proposed by Xcel was for 13,671 dekatherms per day (Dth/day) as opposed to 13,761 Dth/day.

> … Delivered supply provides a service comparable to holding firm pipeline capacity by obtaining a firm commitment for gas at the Town Border Station (TBS). In this arrangement the gas supplier holds firm transportation capacity on Viking, and commits to deliver gas to NSP at our TBS thereby performing the transportation themselves. In return for this commitment, we agree to pay the supplier a demand charge. Our payment of the demand charge typically offsets some of the demand charge the supplier owes to Viking. As a result a delivered supply contract, then, functions similarly to a pipeline transportation contract. This allows us the assurance of firm gas supply needed to meet our design requirements, while also being cost effective.

In addition, the Company changed its design day requirements to serve customers in its demand billed rate class. The Company stated the following:

> In this supplement, we refreshed the level of design day requirements to serve customers in our demand billed rate class. The update increases the projected number of demand customers from 130 in our Petition to 136, and the required demand quantity from 25,775 Dth to 27,566 Dth. The increase of 1,792 Dth raises the overall design day by the same amount, and results in an overall reserve margin of 5.5 percent. The change also adjusts the Jurisdiction Allocation Factor for Minnesota from the previously filed 87.12 percent to 87.27 percent.

As discussed in Comments by the Department, in its Petition, Xcel proposed changes in its demand entitlements that, in total, would have decreased costs from all source systems by approximately $6,065,529. In the Company's *Supplemental Filing*, Xcel stated that as a result of the changes in Viking capacity (as noted above); changes to its design day and Jurisdiction Allocation Factor; and the correction to the delivered supply rate, costs increased by approximately $69,313 relative to the estimate from the Petition.[2] This amount is for Minnesota customers.

The Department responds to the Company's *Supplemental Filing* and *Reply Comments* below.

II. DEPARTMENT ANALYSIS

The Department offers the following analysis of the Company's *Supplemental Filing and Reply Comments*, addressing:

[2] See Petition Attachment 2, Schedule 2, Page 4 of 4 Line 3 compared to *Supplemental Filing* Revised Attachment 2, Schedule 2, Page 4 of 4.

- the revised demand entitlement costs,
- the associated Purchased Gas Adjustment (PGA) cost,
- response to the Department's Comments,
- the reserve margin, and
- February 2021 cold weather event.

A. SUPPLIER ENTITLEMENT CHANGES

As noted above, Xcel originally planned to purchase 13,671 Dekatherms (Dth)[3] per day of delivered supply from a producer/marketer on Viking. The Company acquired two delivered supply agreements totaling 13,700 Dth per day of capacity.[4] The acquired capacity is 29 Dth per day more than what the Company anticipated at the time it filed its Petition. However, the Company stated that this was due to contracting in round numbers. Additionally, Xcel stated that it had "inadvertently listed the wrong rate for a previously acquired delivered supply agreement", and the rate was corrected in its *Supplemental Filing*. The changes are provided in detail in the Company's Supplemental Revised Attachments 1 and 2.

The Department concludes that Xcel's proposed supplier entitlement changes appear reasonable.

B. XCEL'S CHANGE TO ITS DESIGN DAY

In its Supplemental Filing, Xcel indicated that the Company had made changes to its design day for customers in its demand billed rate class. The Company stated, in part, the following:

> The update increases the projected number of demand customers from 130 in our Petition to 136, and the required demand quantity from 25,775 Dth to 27,566 Dth. The increase of 1,792 Dth raises the overall design day by the same amount, and results in an overall reserve margin of 5.5 percent. The change also adjusts the Jurisdiction Allocation Factor for Minnesota from the previously filed 87.12 percent to 87.27 percent.[5]

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[3] Id.

[4] 5,000 Dth/day initial acquisition + 8,700 Dth/day supplemental acquisition = 13,700 Dth per day.

[5] Petition at 2. There is a minor error in this statement. The Company's Jurisdiction Allocation Factor in its Petition was 87.18 percent and not 87.12 percent. However, it is still a slight decrease to 87.27 percent from 87.57 percent in its previous Demand Entitlement Petition to reflect the usage patterns in the *Supplemental Filing*.

All of the changes to the demand billed rate class described above are to customers in Minnesota.[6] The Department concludes that Xcel's proposed changes described above appear reasonable.

C. XCEL'S PGA COST RECOVERY PROPOSAL UPDATE

In its *Supplemental Filing*, Xcel proposed to reflect the costs associated with its proposed demand entitlements in the purchased gas adjustment (PGA) effective November 1, 2020. The demand entitlements in Xcel's Trade Secret Revised Attachment 2, Schedule 1, Page 1 of 3, represent the demand entitlements for which the Company's firm customers will pay. The Company's Revised Attachment 2, Schedule 2 compares the October 2020 PGA costs to the November 2020 PGA costs for several customer classes. The resulting cost changes, related strictly to changes in demand costs, have the following annual rate effects:

- Annual demand costs increase by $0.0248/Dth, or approximately $2.16 annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand costs increase by $0.0266/Dth, or approximately $7.56 annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand costs increase by $0.0238/Dth, or approximately $34.81 annually, for the average Large Commercial customer consuming 1,463 Dth annually; and
- There is 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. In addition, the Company provided an update on Northern Natural Gas (NNG) Federal Energy Regulatory Commission (FERC) Section 4 rate case (RP19-1353) by stating the following at page 3 of its *Supplemental Filing*:[7]

> … On September 29, 2020, the FERC approved the Settlement, making the rates included final. No change to the Northern rates included in our original petition are necessary.

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[6] The applicable tariff sheets are as follows: Section No. 5 8th Revised Sheet No. 3; 7th Revised Sheet No. 3.1; 9th Revised Sheet No. 4; and 5th Revised Sheet No. 4.1 and can be viewed electronically here: Section 5 Rate Schedules.

[7] 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 $5,284,064. In its November 9, 2020 *Reply Comments*, Xcel stated the following:

> On October 23, 2020, the Company received a refund of approximately $4.4 million from Northern for the difference between interim rates in effect January 1, 2020 and April 30, 2020 and the rates approved in the settlement between Northern, NSP, other customers of Northern, and FERC Staff in Docket No. RP19 1353. The Company plans to return this refund in January 2021, as a one time bill credit to natural gas customers taking firm gas sales service.

As a result of the above NNG case at FERC, the refund and bill credit adjustment through the PGA will be reflected in the Company's upcoming Annual Automatic Adjustment (AAA) Report filed in compliance with Minnesota Rules 7825.2390 through 7825.2920 in Docket No. G999/AA-21-114 (Docket 21-114). Thus, based on its review, the Department concludes that the Company's proposal appears to be reasonable.

D. RESPONSE TO DEPARTMENT'S COMMENTS

In the Department's October 29, 2020 Comments at pages 10-11, regarding Great Lakes Gas Transmission (GLGT) and ANR Pipeline (ANR), the Department stated the following:

> 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 application for acquisition of the lease capacity in Docket No. CP20-484-000.

> … Lastly, the Lease Agreement does not adversely affect existing customers.
> … 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.

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Footnotes Omitted.

In its November 9, 2020 Reply Comments, the Company stated that it had intervened in both of the above referenced FERC Dockets in order to ensure that its existing service would “not be adversely affected by the Alberta Express Project.” The Company further stated the following:

> We reviewed the pertinent information related to the project and the capacity lease described in these dockets. The capacity lease does not appear to affect any services, while the facilities to be constructed are located well downstream of the facilities used to serve Xcel Energy. Xcel Energy believes that the proposal will have no effect on our transportation agreements or on service to our customers.

Thus, the Department appreciates the Company’s confirmation that the above referenced FERC Dockets will not impact the Company’s transportation agreements with the interstate pipelines and its firm customers.

E. RESERVE MARGIN

As a result of all of Xcel's proposed entitlement changes, the net change to the Company's reserve margin is a decrease of 385 Dth/day on a Minnesota-jurisdictional basis, resulting in a reserve margin of 5.52%.[8] This reflects a decrease in the reserve margin compared to the 2019-2020 heating season's reserve margin of 6.61%. As discussed in the Department's Comments, the 2020-2021 reserve margin is not unreasonable.

F. *FEBRUARY 2021 COLD WEATHER EVENT*

As a result of the recent cold weather event, on February 18, 2021, the Commission issued its Notice of Commission Special Planning Meeting (*February 18, 2021 Notice)* to be held on February 23, 2021 in order to provide the Commission with information about the impacts of the February 2021 cold weather event and the increase in natural gas prices. Questions listed in the *February 18, 2021* Notice included:

1. Why did natural gas prices go up in February 2021 and what were the natural gas spot and index prices before and after this cold weather event?

2. How will this affect customer bills now and in the future?

3. Were any firm customers interrupted during this time period due to natural gas system issues, including low pressure, need to reinforce specific areas of the distribution system, inability to get delivery from suppliers, use of storage and peak shaving? And, if so, in what order were customers interrupted and why?

4. Were any interruptible customers curtailed during this time period and in what order were they curtailed?

Also on February 18, 2021, Commission Staff issued a Memorandum (*Memo*) identifying the dockets gas companies' gas costs are reviewed in and expanding on the list of questions in the *February 18, 2021 Notice*.[9] While one of the questions above refers to customers who fail to curtail or interrupt their use of natural gas supplies when requested to do so by a utility, it does not directly impact Xcel's need to procure entitlements or calculate the design day as those calculations are based on firm requirements and interruptible usage is not included. However, some and/or all the questions raised in the *February 18, 2021 Notice* and *Memo* will be followed up on by the Department in the upcoming

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[8] The 5.52% reserve margin is a slight decrease from the 5.66% reserve margin reflected in Xcel's initial Petition. See Department Supplemental Comments Attachment 1.

[9] See Department Attachment 2.

AAA report in Docket No. 21-114 and/or in Docket No. E,G999/CI-21-135 (Docket 21-135) wherein the Commission has opened an investigation to learn about each utility's operational experiences and the natural gas price impacts during the recent February 2021 Cold Weather Event.

III. DEPARTMENT RECOMMENDATION

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, 2020.

/ja

Supplemental Comments 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**	469,356	3,974	0.85%	750,974	7,278	0.98%	792,448	(385)	-0.05%	41,474	5.52%
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%			1.20%			1.18%		5.75%

	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			0.0884	1.6000	1.6884	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%	0.0914	1.5880	1.6794	1.4743

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

MINNESOTA
PUBLIC UTILITIES COMMISSION

NOTICE OF COMMISSION SPECIAL PLANNING MEETING

Issued: *February 18, 2021*

DATE: Tuesday, February 23, 2021

TIME: 2:30 – 3:30 p.m.

LOCATION: On-line via WebEx

AGENDA: February 2021 Natural Gas Prices

This planning meeting will provide an opportunity for utilities and partner government agencies to provide the Commission with information about the impact of the February 2021 cold weather event and increase in natural gas prices. (A copy of the agenda for this meeting is attached.)

Viewing Instructions and any additional meeting materials, if any, will be posted on the Commission's website.

SCHEDULING CHANGES? Find out if a meeting is canceled. Call (toll-free) 1-855-731-6208 or 651-201-2213 or visit mn.gov/puc

CHANGE YOUR MAILING PREFERENCES: E-mail docketing.puc@state.mn.us or call 651-201-2234

If reasonable accommodations are needed to enable you to fully participate in a Commission meeting such as sign language or large print materials, please call 651-296-0406 or 1-800-657-3782 at least one week in advance of the meeting.

Persons with a hearing or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

MINNESOTA
PUBLIC UTILITIES COMMISSION

Commission Special Planning Meeting

Tuesday, February 23, 2021, 2:30 – 3:30 pm
February 2021 Natural Gas Prices

A. Comments from Minnesota Natural Gas Local Distribution Companies (LDCs)

(no more than 5 to 7 minutes each)

- Xcel Energy
- CenterPoint Energy
- Minnesota Energy Resources
- Great Plains Natural Gas co.
- Greater Minnesota Gas

1. Why did natural gas prices go up in February 2021 and what were the natural gas spot and index prices before and after this cold weather event?

2. How will this affect customer bills now and in the future?

3. Were any firm customers interrupted during this time period due to natural gas system issues, including low pressure, need to reinforce specific areas of the distribution system, inability to get delivery from suppliers, use of storage and peak shaving? And, if so, in what order were customers interrupted and why?

4. Were any interruptible customers curtailed during this time period and in what order were they curtailed?

B. Comments and Questions for the LDCs from State Agencies

- Minnesota Department of Commerce, Division of Energy Resources
- Minnesota Office of the Attorney General, Residential Utilities Division

MINNESOTA
PUBLIC UTILITIES COMMISSION

MEMORANDUM

Date: February 18, 2021

To: Commissioners
Will Seuffert, Executive Secretary

From: Bob Harding, PUC Staff

Re: Commission Special Planning Meeting – February 23, 2021
February 2021 Cold Weather Event and its Impact on Natural Gas Prices

Background Information on Fuel Cost Dockets and Questions and Topics for Further Discussion

On Friday, February 12, 2021, there was a large increase in natural gas prices in the wholesale natural market. Anecdotal reports suggest natural prices increased from approximately $3 per dekatherm to as much as or more than $200 per dekatherm. Most of this increase in price for gas delivered to Minnesota appears to have been weather and demand related. This was evidenced by increases in various index prices for natural gas at locations throughout the United States.

The last time there were significant increases in natural gas prices and disruptions in natural gas service in Minnesota was during the cold weather event of January 28 through February 1, 2019. One of the results of the 2019 investigation was that Xcel Energy and CenterPoint Energy were also required to submit information about system reinforcement projects completed during the year.[1] Another requirement was that the gas utilities update and modify the provisions for failure to curtail penalties in their tariffs and thoroughly review their procedures for handling cold weather events.

The purpose of this memo is to identify the dockets gas companies' gas costs are reviewed in. Also, at the end of this memo is a list of questions that expands on the list of questions that are on the agenda for the special planning meeting on Tuesday, February 23, 2021. If there is interest in collecting additional information, one or more of these questions could be asked at

[1] ORDER APPROVING MODIFICATION OF CURTAILMENT PENALTIES AND TARIFFS AND REQUIRING REPORTS, In the Matter of a Commission Inquiry into the Impact of Severe Weather in January and February 2019 on Utility Operations and Service, Docket No. E,G-999/CI-19-160 (November 6, 2019)

the Commission meeting or the gas companies could be asked to respond to these questions in writing after the meeting.

There is also a brief discussion about the impact this increase in natural gas prices could have on electric prices, however, staff expects this will be discussed at the Commission's MISO Quarterly Review on March 5, 2021.

Gas Cost Dockets

The month-to-month changes in the commodity cost of gas that are applied to customer bills are reported and reviewed by the Department of Commerce. These reports are typically submitted towards the end of the month and include the LDC's forecasted commodity cost of gas for the following month.[2] The wholesale prices the gas companies expect to pay in March would be applied to customer bills for gas consumed in March. These filings are not submitted to or routinely reviewed by the Commission.

The gas utilities are also required to obtain approval for changes (increases and decreases) in the amount of pipeline capacity they have an entitlement to under contract with the pipelines. These are the annual change in demand entitlement filings that are reviewed to ensure the LDCs have enough capacity under contract to provide service under design-day weather conditions. As a result of the planning issues that were discovered in the 2019 investigation, the Department has begun to include a review of whether the LDCs have coordinated its planning for the amount of pipeline capacity it needs with the planning for how much distribution capacity is needed on its own system. The changes in demand entitlement are provisionally approved when filed pursuant to Commission rules.[3]

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[2] Minn. Rules, part 7825.2910, subpart 1. Filing By Gas Utilities. Monthly reports. Gas utilities shall submit monthly to the department purchased gas adjustment reports, which must include: A. a summary of adjustments that were implemented in the previous month and the computation of each adjustment; B. an explanation of significant changes between the base gas cost and current cost, quantified as to changes in price and source of gas; C. the estimated previous month's and year-to-date commodity-delivered gas cost by supplier; D. estimated gas volumes purchased from suppliers whose gas rates are not regulated by the Federal Energy Regulatory Commission; and E. estimated costs of gas purchased in item D expressed as a percentage of all commodity-delivered gas costs and demand-delivered gas costs. The department shall summarize the monthly reports every three months and submit the summary to the commission for review.

[3] Minn. Rules, part 7825.2910, subpart 2. Filing By Gas Utilities. Filing upon change in demand. Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another. A filing must contain: A. a description of the factors contributing to the need for changing demand; B. the utility's design-day demand by customer class and the change in design-day demand, if any, necessitating the demand revision; C. a summary of the levels of winter versus summer usage for all customer classes; and D. a description of design-day gas supply from all sources under the new level, allocation, or form of demand.

2020-2021 Change in Demand Entitlement filings

Company	Docket No.	Status
Xcel Energy	M-20-633	Pending
CenterPoint Energy	M-20-565 & M-21-102	Pending
MERC	M-20-636 & M-20-637	Order - 1/25/2021
Great Plains Natural Gas	M-20-562	Pending
Greater Minnesota Gas	M-20-391	Commission meeting – 3/11/2021

Total annual gas costs are reviewed when the LDCs submit their automatic adjustment of charges reports on September 1st for the previous gas year that includes the twelve-month period of July 1st through June 30th.[4] These reports also include an annual true-up rate adjustment filing for the previous gas year. In the annual true-up, the gas companies are allowed to collect/refund the difference between what they collected from customers and what they paid suppliers.

Annual Automatic Adjustment Reports

Gas Year	Docket No.	Status
Jul. ’17 – Jun. ‘18	AA-18-374	Order – 11/13/2019
Jul. ’18 – Jun. ‘19	AA-19-401	DOC Report - Expected 5/20/2021
Jul. ’19 – Jun. ‘20	AA-20-172	DOC Report – Expected 5/20/2021
Jul. ’20 – Jun. ‘21	AA-21-114	Initial Filings Expected - 9/1/2021

Xcel, CenterPoint and MERC are also authorized to recover the cost of using financial instruments to hedge their cost of gas. Costs are recovered through their monthly purchased gas rate adjustments. These are multi-year rule variances and they have been in effect for a long time and extended several times for each utility.

Gas Hedging – Rule Variances

	Docket No.	Status
Xcel Energy	M-19-703	Order – 2/12/2020
CenterPoint Energy	M-19-699	Order – 1/13/2020
MERC	M-20-833	Pending

One of the conditions of the financial hedging rule variance granted to CenterPoint is that CenterPoint submit its gas supply plan each year in a compliance filing. In addition, CPE typically meets with PUC and Department staff to go over their plan.

Staff does not believe any of the other gas utilities are required to submit annual compliance filings with their gas supply plans. However, it is staff’s understanding that Xcel meets with the Department each year to review Xcel’s plan.

[4] Minn. Rules, part 7825.2910, subpart 4. Filing By Gas Utilities. True-up filing. Gas utilities shall file and implement on September 1 of each year the true-up adjustment computed under part 7825.2700, subpart 7, for the previous year commencing July 1 and ending June 30.

In addition, in 1994, the Commission declined to adopt a formal gas integrated resource planning process in which a gas supply plan would probably have been required as well as a recognition of the LDC's DSM programs.[5]

Electric Price Issues

The cold weather and increase in natural gas prices appear to have also had an impact on the electric utilities. Mainly through MISO energy prices (LMPs) which impact utilities' energy prices in different ways. (Day-ahead vs Real-time LMP, long or short in energy position.) Most of the Minnesota utilities clear the majority of their load in the day ahead market; hence the day-ahead LMP will have the most impact on ratepayers' rates.

The real-time LMP is very volatile and receives the most attention in the media. However, it can have lesser impact to ratepayers. Also, electric utilities have a natural hedging position with their own generators. As long as the utility is not short with energy, the maximum risk exposure to a utility is capped by its own fuel price for generators. If Minnesota electric utilities were able to sell energy into the MISO market they may have benefitted from this cold weather event or if they were short on generation, they may have incurred additional energy cost based on their generation capability.

Staff does not have specific information about whether Xcel, MP or Otter Tail were net sellers or buyers of energy during this time period, however, if they were short capacity and buying energy, then any excess energy costs above forecast would flow through the FCA. Under the Commission's revised FCA procedures, if actual (total) FCA costs for the year exceed forecasted costs then, when they make their annual compliance filing, the utilities may seek to recover the additional costs.

If the electric utilities were net sellers then ratepayers may be due refunds. In an April 15, 2020 compliance letter, Docket No. E-002/AI-19-622, Xcel explained how it handles merchant energy trading activity:

> Xcel Energy's proprietary, or non-asset based, trading activity is one of two main categories of short-term wholesale trading, the other being asset-based trading. Asset-based transactions involve the sales of excess energy or capacity from Company-owned generation assets. Non-asset based (or proprietary) transactions, on the other hand, are undertaken as energy market opportunities to make revenues, and are unrelated to meeting the needs of the "native load" customers (retail customers and requirements wholesale customers taking service at cost based rates).

[5] ORDER DECLINING TO ADOPT TWO FEDERAL STANDARDS, In the Matter of an Investigation into Standards Regarding the Encouragement of Investments in Conservation and Energy Efficiency by Gas Utilities under 15 USC 3203 as amended by Section 115 of the Energy Policy Act of 1992, Docket No. G-999/CI-93-895 (May 4, 1994)

> Xcel Energy's traders conduct both proprietary and asset-based trading. The Company does not, however, intermix its proprietary and asset-based trades. In other words, proprietary transactions are only made to or from the Proprietary Book, and asset-based trades are only made to or from the Generation Book.
>
> Prior to the Company's 2010 Rate Case (Docket No. E002/GR-10-971), we shared non-asset based margins (revenues less costs) with customers. In the settlement of the 2010 Rate Case, however, the Company agreed to change the ratemaking treatment of non-asset based trading margins: non-asset based margins, as well as the fully-allocated costs of those activities, now are removed from the cost of service.

Staff also notes that in 2020, the Commission approved MP's request to shift its accounting for wholesale sales credits to its fuel clause adjustment rather than including them in its calculations for establishing base rates.[6] The majority of MP's sales credits are for a single large wholesale customer, however, asset-based wholesale sales credits may also arise from opportunity-based transactions in the MISO market. The Commission may want to ask MP to explain how it handles this revenue for fuel cost recovery purposes.

Staff is unaware of possible cost impacts to Otter Tail's customers; however, a review of Otter Tail's forecasted February 2021 FCA costs were $10.2 million of which $5.2 million, or 51%, was purchased power. OTP's asset-based margins were only forecasted to be $84,000. Based on this information, Staff suspects that actual February 2021 FCA costs may be higher than forecasted.

Staff expects this could be explored in more detail at the Commission's MISO Quarterly Review on March 5, 2021.

[6] In the Matter of the Emergency Petition of Minnesota Power for Approval to Move Asset-Based Wholesale Sales Credits to the Fuel Clause Adjustment and Resolve Rate Case, Docket No. E-015/M-19-429

Possible Questions and Topics for Further Discussion

1. Why did natural gas prices go up in February 2021, how high are natural gas prices now, and how long are natural gas prices expected to stay at this level?

2. How much higher are these prices than the forecasted cost of gas in the February 2021 monthly Purchased Gas Adjustment (PGA) report?

3. How will this affect gas customers' bills for February 2021, March 2021 and the annual true-up of gas costs for the July 1, 2020 through June 30, 2021 gas year?

4. For the Minnesota LDCs that engage in natural gas price hedging, please describe the effect this had on your company's cost of gas during this time period?

5. How will this affect customers who may already be having trouble paying their gas bills?

6. Has this cold weather event and the high gas prices had a disproportionate impact on Minnesota's BIPOC communities or the gas utilities ability to provide service to Minnesota BIPOC communities?

7. Were there any problems during the February 2021 cold weather with the delivery of natural gas into the facilities and systems operated by Minnesota LDCs?

8. Have any Minnesota LDCs had to provide local reinforcement to their distribution systems to maintain service to firm customers or have any firm customers been interrupted during this time period?

9. Have any Minnesota LDCs curtailed service to interruptible customers and to what extent?

10. Have interruptible customers complied with curtailment requests from their LDCs?

11. Have the cold weather related events in Texas and elsewhere had any clearly identifiable impact on any aspect of Minnesota utilities operations and ability to maintain expected levels of customer service?

12. Have the Minnesota LDCs communicated effectively with their customers about gas prices during this cold weather?

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
Supplemental Comments

Docket No. G002/M-20-633

Dated this 25th day of February 2021

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_20-633_M-20-633
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-633_M-20-633
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-633_M-20-633
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_20-633_M-20-633
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_20-633_M-20-633
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-633_M-20-633
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_20-633_M-20-633
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_20-633_M-20-633
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-633_M-20-633
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-633_M-20-633

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-633_M-20-633
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_20-633_M-20-633
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_20-633_M-20-633
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_20-633_M-20-633
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_20-633_M-20-633
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-633_M-20-633
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-633_M-20-633
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-633_M-20-633
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-633_M-20-633
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-633_M-20-633

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_20-633_M-20-633
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_20-633_M-20-633
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-633_M-20-633
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-633_M-20-633
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_20-633_M-20-633
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-633_M-20-633
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_20-633_M-20-633
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_20-633_M-20-633
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-633_M-20-633
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-633_M-20-633

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_20-633_M-20-633
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-633_M-20-633
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_20-633_M-20-633
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-633_M-20-633
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_20-633_M-20-633
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_20-633_M-20-633