April 13, 2022 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/AA-20-417

Dear Mr. Seuffert:

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

The Petition of Northern States Power Company d/b/a/ Xcel Energy (Xcel) for Approval of its Annual True-up Compliance Report for its 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges.

The Petition was filed on March 1, 2022 by:

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

The Department recommends the Minnesota Public Utilities Commission (Commission) **approve Xcel's Petition**. The Department is available to answer any questions the Commission may have in this matter.

Sincerely,

/s/ MARK JOHNSON
Financial Analyst Coordinator

MJ/ar
Attachment

Before the Minnesota Public Utilities Commission

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

Docket No. E002/AA-20-417

I. INTRODUCTION

On March 1, 2022, Northern States Power d/b/a Xcel Energy (Xcel or the Company) filed its Annual True-up Compliance Report for its 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges (Petition) with the Minnesota Public Utilities Commission (Commission). The Company submitted its Petition pursuant to the Commission's June 12, 2019 *Order* in Docket No. E999/CI-03-802 and the applicable reporting requirements provided for in the rules that govern the automatic adjustment of charges, Minnesota Rules 7825.2800 to 7825.2840. Xcel requests the Commission approve its 2021 True-up Report, its proposal to recover its 2021 under-collected fuel costs of $81.8 million, and its Electric AAA reporting requirements included in its report.[1]

II. DEPARTMENT ANALYSIS

The Minnesota Department of Commerce, Division of Energy Resources (Department) reviewed Xcel's Petition to determine (1) whether the Company's actual 2021 Fuel Clause Adjustment (FCA) costs were reasonable and prudent, (2) whether the Company correctly calculated the 2021 true-up amount and recovery factors for its FCA, and (3) whether the Petition complies with the reporting requirements set forth in the applicable Minnesota Rules and Commission Orders.

A. SUMMARY OF RECENT FUEL CLAUSE ADJUSTMENT REFORM

Minn. Stat. § 216B.16, subd. 7, authorizes the Commission to allow a public utility to automatically adjust charges for the cost of fuel. Prior to 2020, utilities would (1) adjust their FCA rates monthly to reflect, on a per kWh basis, deviations from the base cost of energy established in the utility's most recent general rate case and (2) file monthly and annual reports to be reviewed for accuracy and prudence.

In 2003, the Commission initiated an investigation (Docket No. E999/CI-03-802) to explore possible changes to the FCA and invited stakeholders to comment on the purpose, structure, rationale, and relevance of the FCA. The Commission's December 19, 2017 *Order* in Docket No. E999/CI-03-802 approved certain reforms to the FCA mechanism. Specifically, Point 1 of the December 19, 2017 *Order* approved the Department's FCA reform proposals as follows:

[1] Petition at 18.

a. the Commission will set recovery of the utility's fuel, power purchase agreements, and other related costs (fuel rates) in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact.

b. each electric utility will publish the monthly fuel rates in advance of each year to give customers notice of the next year's monthly electric fuel rates.

c. the monthly fuel clause adjustment will not operate – each electric utility will charge an approved monthly rate.

d. utilities will be allowed to track any changes in $/MWh fuel costs that occur over the year and there will be no carrying charge on the tracker.

e. annually, each electric utility will report actual $/MWh fuel costs in each month by fuel type (including identification of costs from specific power purchase agreements) and compare the annual revenue based on the fuel rates set by the Commission with annual revenues based on actual costs for the year.

f. each electric utility will refund any over-collections and show prudence of costs before allowing recovery of under-collections. If annual revenues collected ($/MWh) are higher than total actual costs, the utility must refund the over-collection through a true-up mechanism. If annual revenues collected are lower than total actual costs), the utility must show why it is reasonable to charge the higher costs (under-collections) to ratepayers through a true-up mechanism.

The Commission's December 12, 2018 *Order* in Docket No. E999/CI-03-802 modified the FCA reform previously approved in the Commission's December 19, 2017 *Order* in the same docket. In particular, the December 12, 2018 *Order*:

- Established a January 1, 2020 implementation date for the FCA reform.
- Required the utilities, following the implementation of the FCA reform, to file an annual true-up by March 1 of each year following the relevant calendar year.
- Discontinued the requirement for utilities to submit monthly automatic adjustment filings.
- Granted the relevant utilities a variance to Minnesota Rule 7825.2600, subp. 3, which requires that the FCA be applied to base recovery of fuel costs on a monthly basis. Under the new FCA process, the monthly FCA would be irrelevant, because, instead, the Commission would use an annual forecast of fuel costs to adjust base fuel rates annually.

The Commission's June 12, 2019 *Order* in Docket No. E999/CI-03-802 provided additional details to finalize the FCA reform. Specifically, the June 12, 2019 *Order* approved, among other things:

- Variances to Minnesota Rules 7825.2800 through 7825.2840 to accommodate the new FCA process by modifying the filing deadlines contained in these rules.
- A procedural schedule, as shown in Appendix A of the *Order*.
- A threshold of plus or minus five percent of all FCA costs and revenues to determine whether an event qualifies as a significant, unforeseen impact that may justify an adjustment to the approved fuel rates. Utilities are permitted to implement revised rates following a 30-day notice period, subject to a full refund, if no party objects to the revised rates.
- Tracking under or over-recovered FCA costs as regulatory assets or liabilities, respectively, using FERC Account 182.3.
- Information requirements for the annual forecast and true-up filings for all electric utilities, including the reporting requirement changes outlined in Attachments 1, 2, and 3 of the March 1, 2019 joint comments[2] in Docket No. E999/CI-03-802 and the requirement that the annual true-up filings include a complete analysis and discussion of the consequences of self-commitment and self-scheduling of their generators, including the annual difference between production costs and corresponding prevailing market prices.
- Tariff changes reflected in Attachments 4, 5, and 6 of the March 1, 2019 joint comments[3] in Docket No. E999/CI-03-802.
- Discontinuation of Xcel's reporting of Part H, Section 4 narrative and Schedule 1 (transformers); Part I (MISO Day 1); Part J, Section 5, Schedules 1, 3-6 (MISO Day 2); Part K, Section 5, Schedule 3 (transformer maintenance); Part K, Section 4, Schedule 3 (designated resource planning for MISO).

The June 12, 2019 *Order* also permitted utilities to provide wind curtailment reporting as part of their annual true-up filings and permitted Xcel to implement its November and December 2019 true-up on March 1, 2020, subject to Commission review and approval.

On December 19, 2019, Xcel filed a petition requesting Commission approval to operate its King and Sherco 2 coal-fired plants on a seasonal basis in Docket No. E002/M-19-809. The Commission approved Xcel's request in its July 15, 2020 Order in the same docket.

On May 1, 2020, in Docket No. E002/AA-20-417, Xcel filed its initial petition requesting approval of its 2021 annual forecast for its FCA. On July 31, 2020, the Company filed reply comments and revised its 2021 annual forecast for its FCA which included 26,988,067 megawatt hours (MWhs) in Minnesota sales and $749,743,000 in Minnesota fuel/purchased power costs, for an average fuel/purchased

[2] In the March 1, 2019 joint comments, Attachment 3 corresponds to Xcel.

[3] In the March 1, 2019 joint comments, Attachment 6 corresponds to Xcel and reflects the Company's current FCA Rate Schedule, Section 5, Sheet Nos. 91.0 – 91.3, as approved by the Commission's June 12, 2019 *Order* in Docket No. E-999/CI-03-802 (Part A, Attachment 9 to the instant Petition is the proposed nineteenth revision of the Company's FCA tariff).

power cost per MWh of $27.78.[4] The Commission approved Xcel's revised 2021 forecast in its December 22, 2020 *Order* in Docket No. E002/AA-20-417.

On August 27, 2021, Xcel filed a petition in Docket No. E002/AA-20-417 requesting the Commission approve the Company's request to adjust its 2021 fuel forecast rates to collect an under-recovered balance of $25.2 million in FCA costs through June 2021. Since no party objected to the Company's proposal, Xcel implemented the $25.2 million increase to fuel costs for the months of October through December 2021.[5]

The instant Petition provides the true-up between the Company's actual fuel/purchased power cost recovery through its FCA and the actual corresponding fuel/purchased power costs Xcel incurred for the period of January 1 through December 31, 2021. The Company's Rate Schedule Section 5-91 provides for the FCA.

B. PURPOSE OF XCEL'S PETITION

In its Petition, Xcel: (1) demonstrated that the Company's fuel/purchased power costs for 2021 were reasonable and prudent, (2) requested Commission approval of the Company's 2021 FCA true-up amount of $81.8 million to be collected over the 12-month period beginning September 1, 2022, and (3) requested Commission approval of the FCA true-up compliance reporting required by Minnesota Rules 7825.2800 – 7825.2840 and applicable Commission Orders. The Department discusses each of these three areas in the following sections.

C. PRUDENCY AND REASONABLENESS OF XCEL'S ACTUAL 2021 FUEL/PURCHASED POWER COSTS

1. Summary of 2021 Fuel/Purchased Power Costs and Sales

Xcel's actual 2021 fuel/purchased power costs were significantly higher than the forecasted costs the Commission approved in its December 22, 2020 Order. However, Xcel's actual MWh sales were also higher than forecasted. The combination of these two factors resulted in an under-recovery of $81.8 million for the Minnesota jurisdiction.

The following table summarizes and compares select energy sales and cost data relevant to Xcel's 2021 FCA true-up:

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[4] See Xcel's July 31, 2020 Reply Comments in Docket No. E002/AA-20-417, Attachment D.
[5] The Department recommended approval of Xcel's proposal in its September 24, 2021 Letter in Docket No. E002/AA-20-417.

Department Table 1: Comparison of Select Forecasted to Actual Data for Xcel's 2021 Fuel Clause Adjustment True-up for Minnesota Jurisdiction[6]

Data Description	*2021 Actual (A)*	*2021 Forecast (B)*	*Percentage Difference (A-B)/B*
MWh Sales Subject to Cost of Energy	28,195,869	26,988,067	4.5%
Total Cost of Fuel/Purchased Power	$894,089,000	$749,743,000	19.3%
Average Fuel/Purchased Power Cost Per MWh	$31.71	$27.78	14.1%

Department Table 1 shows that Xcel's relevant 2021 MWh sales were approximately 4.5 percent higher than forecasted and that the Company's total system actual fuel/purchased power costs recoverable through the FCA for 2021 were about 19.3 percent higher than forecasted, which results in an approximate 14.1 percent increase in the average fuel/purchased power cost on a per MWh basis.

The cost and offsetting credit/revenue components of the Company's actual and forecasted 2021 fuel/purchased power costs recoverable through the FCA can be broken into several major categories, as summarized in the following table:

[6] Data in Department Table 1 retrieved from Petition, Part A, Attachment 1.

Department Table 2: Xcel's Forecasted and Actual 2021 FCA Cost Summary (in 1000's)

		2021 Actuals[7]	2021 Forecast[8]	Percentage Difference
1	Xcel's Generating Stations	$563,490	$407,117	38.4%
2	Plus: LT Purchased Energy	$559,674	$497,118	12.6%
3	Plus: LT CSG[9]	$183,652	$189,834	(3.3%)
4	Plus: ST Market Purch[10]	$315,027	$9,302	3,286%
5	Total System Costs	$1,621,843	$1,103,372	46.9%
6	Less: Sales Revenues[11]	($437,200)	($136,299)	220.8%
7	Less: CSG-AMC[12]	($110,745)	($157,160)	(29.6%)
8	Less: Windsource	($12,169)	($6,004)	102.7%
9	Less: Renewable Connect	($6,190)	($6,286)	(1.5%)
10	Net System FCA Costs	$1,055,539	$797,623	32.3%
11	Total System Sales MWh	39,923,939	38,215,037	
12	Less: Windsource MWh	(440,556)	(212,927)	
13	Less: Renewable Connect	(177,779)	(183,055)	
14	Net System Sales MWh	39,305,604	37,819,056	(3.9%)
15	MN Juris. Sales MWh's	28,814,204	27,384,049	
16	Less: Windsource MWh's	(440,556)	(212,927)	
17	Less: Renewable Connect	(177,779)	(183,055)	
18	**Net MN Sales MWh's**	**28,195,869**	**26,988,067**	**4.5%**
19	MN FCA Costs	$758,124	$569,448	33.1%
20	Add: CSG-AMC[13]	$110,646	$157,160	(29.6%)
21	Add: Laurentian Buyout	$13,192	$13,069	0.9%
22	Add: Pine Bend Buyout	$0	$0	
23	Add: Benson Buyout	$10,249	$10,066	1.8%
23a	Other[14]	$1,834	-	-
24	**Net MN FCA Costs**	**$894,089**	**$749,743**	**19.3%**
25	**Net MN FCA Costs $/MWh**	**$31.71**	**$27.78**	**14.1%**

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[7] Data in Department Table 2 retrieved from Petition, Part A, Attachment 2.
[8] Per Xcel's July 1, 20 Comments, Page 8, Table 2; Per Xcel's Response to Department Information Request No. 5, Attachment A. Also from Petition, Part A, Attachment 1.
[9] Long-term purchased energy from Community Solar Gardens (CSGs).
[10] Includes ST Market Purchases of $85,141 + MISO Costs of $229,886.
[11] Revenues received from MISO attributable to the Company's asset-based sales.
[12] Community Solar Gardens – Above Market Costs.
[13] *Id*.
[14] Includes SES Exemption Recovery, Saver's Switch Discount Adjustment, and Other. See Petition at 14-15.

Department Table 2 shows that Xcel's actual 2021 FCA costs were 19.3 percent higher than forecasted on a Minnesota jurisdictional basis (line 24). However, Xcel's actual 2021 sales were also 4.5 percent less than forecasted on a Minnesota jurisdictional basis (line 18). Taken together, these changes resulted in a 14.1 percent increase to Minnesota's net FCA costs on a per MWh basis (line 25).

2. Explanation of Variances

Beginning on page one of its Petition, Xcel stated its 2021 actual fuel/purchased power costs and sales were higher than forecasted primarily because of:

- higher congestion costs from the MISO market than forecasted;
- increased fuel costs for gas generation due to higher gas prices; and
- increased fuel costs for coal generation in response to higher gas prices and resulting market LMPs.

Xcel also stated higher market LMPs led to greater than forecasted asset-based sales volumes and revenues, which also increased generation volume from both gas and coal generators. According to Xcel, the higher asset-based sales revenues served to offset some of the increased costs for 2021. A more detailed explanation of variances by generation type is provided on pages 6-15 of the Petition.

The Department discusses these and other significant issues in greater detail below.

a. Retail Sales

Beginning on page 13 of its Petition, Xcel stated its actual 2021 sales were 1,430,154 megawatt hours (MWh) higher than forecasted.[15] Xcel stated contributing factors for the variance include greater than anticipated residential class COVID pandemic impacts from continued social distancing and work-from-home measures, 2021 weather impacts, lower than expected combined heat and power generation, and other non-specific factors. A detailed sales variance table is provided on page 14 of the Petition.

Based on our review, the Department concludes Xcel has reasonably explained its variance between actual and forecasted 2021 retail sales.

b. MISO Congestion Costs

On page five of its Petition, Xcel stated the following regarding 2021 congestion costs:

> Another pressure that drove costs much higher than forecast was increasing costs from congestion. Recall that Locational Marginal Prices consist of three components: system energy cost (which varies for each market interval but is constant across the MISO footprint for that interval),

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[15] Includes Renewable*Connect and Windsource sales, which are excluded from the FCA.

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> congestion costs, and losses. Put simply, congestion costs are a signal that transmission capacity in the market is constrained. Congestion costs saw a step increase in April 2021, remained high through the summer of 2021, and saw another step increase in September 2021 when gas prices rose to their highest level of the year. The in-servicing of the new Huntley-Wilmarth transmission line provided some relief in December 2021, but costs still remained much higher than forecast in our July 2020 Reply Comments, the forecast approved in this docket. Congestion was high in MISO due to substantial additions of renewable energy, concentrated in certain wind-rich regions of MISO. Additions of generation have outpaced transmission capacity, limiting the ability to transport lower-cost wind generation to load zones in MISO, instead leaving higher priced resources to set marginal market prices. On-going transmission work in MISO to bring new lines, such as Huntley-Wilmarth, into service and actions such as reconfigurations and dynamic line ratings may help mitigate some of the congestion in the near term. However, additional investment in transmission will likely be necessary to address congestion over the longer term.

Xcel provided the following table detailing its MISO congestion costs and related financial charges on page 13 of its Petition:

Table 2: MISO Charge Type Forecast to Actuals ($000s)

Category	Actual	Forecast	Variance
Congestion	$230,065	$33,187	$196,878
FTR	($59,818)	($30,339)	($29,479)
Incremental Transmission losses	$4,368	($7,087)	$11,455
RSG/RNU	$10,430	$5,588	$4,842
ASM	($2,203)	($1,110)	($1,092)
MISO Charges TOTAL	$182,842	$239	$182,603

In addition, in accordance with the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792, Xcel provided information regarding its top ten generation-load paths with the highest congestion costs along with related offsetting financial transmission right revenues (FTRs).[16]

As shown in the above table, Xcel's 2021 congestion costs are significantly higher than forecasted. In addition, Xcel's offsetting 2021 FTRs are also higher than forecasted. However, the higher FTRs only partially offset the higher congestion costs. Given these significant increases, the Department asked Xcel several questions as discussed below.

[16] See Part B, Attachment 1, Page 13 of Petition.

The Department asked Xcel, in Department Information Request No. 14a, if its 2021 MISO Auction Revenue Rights (ARRs), which also serve as an offset to congestion costs, were included in the above table. Xcel replied that its ARRs are embedded in the table since they are converted to FTRs.[17] Xcel stated ARRs are allocated to Market Participants based on their firm historical usage of the transmission network during the MISO ARR Reference Year of March 2004 to February 2005. Xcel stated it converts all of its ARRs to FTRs. In addition, Xcel stated participants that hold FTRs receive payment for congestion revenues on specific paths and are frequently used to provide a financial hedge to manage the risk of congestion costs. A complete copy of Xcel's Response to Department Information Request No. 14 is provided in Attachment 1 of these comments.

The Department also asked Xcel, in Department Information Request No. 14b, to explain all the reasons why its MISO charges for congestion and FTRs were so high for 2021. Xcel replied:

> At a high level, congestion is caused by temporary mismatches between generation and available transmission. Congestion is relieved over time when new transmission investments are made. In the interim, the ARR/FTR market construct was developed to protect long-term, historical rights to the transmission system. However, this market has very limited provisions for incremental portfolio changes. Northern States Power Company is not entitled to ARRs or FTRs on transmission paths between new resources and our load, and the Company has limited options to mitigate congestion cost in the near term. At the same time, transmission congestion (and congestion cost) has increased as renewable resources have been built up across the MISO footprint. The combination of this development with limited offsetting ARRs or FTRs results in the Company being exposed to the costs of transmission congestion related to new resources in a way that it had not been previously.
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> The MISO Independent Market Monitor (IMM) discussed the rise in congestion cost at the MISO Board Meeting on December 7, 2021. The IMM presented Figure 1, below, representing the rise in congestion costs across the entire market. The three columns furthest to the left illustrate the significant rise in congestion costs between 2019 and 2021, and further, point to the role of wind generation in the Midwest as a key driver (as demonstrated by the significant increase in the "Midwest – Wind" light pink area of the column year over year)….

The Department asked Xcel, in Department Information Request No. 14c, whether it expected MISO congestion costs and FTRs to be an ongoing problem and continue at 2021 levels in 2022 and 2023. Xcel replied:

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[17] A complete copy of Xcel's Response to Department Information Request No. 14 is provided in Attachment 1 of these comments.

> Congestion costs are inherent to the functioning of the MISO energy market, and the recent increase in congestion costs is more of a systemic than a singular change. Because we anticipate that congestion costs will persist, the Company is working to identify ways to mitigate these costs through transmission operation and expansion. As described below, the Company has several initiatives to address increased congestion costs.

Finally, the Department noted that MISO and the Organization of MISO States (OMS) were looking at FTR and ARR underfunding and expressed concerns with participants not managing their exposure to congestion costs. As a result, the Department asked Xcel, in Department Information Request No. 14d, to explain what the Company was doing to manage their exposure to congestion costs. Xcel replied:

> The increased costs are impacted by many different aspects of system operations, but the common factor is that the transmission system in the Upper Midwest is oversubscribed and cannot support all the wind generation that has recently gone into service. Factors impacting congestion costs were wind generation going into service prior to the completion of transmission upgrades required for the generation to interconnect along with a number of significant transmission outages. In other words, there was more wind generation installed in the western subregion of MISO than can be delivered to meet customer demand throughout the MISO footprint. To address this common factor in the long term, a cost-effective plan for transmission expansion must be implemented. Below, we discuss the necessary long-term solutions, as well as near- and medium-term partial solutions to the problem.
>
> **Long-Term Solutions**: The MISO Long Range Transmission Planning (LRTP) process is currently evaluating the type of cost-effective solutions to not just address existing limitations but ensure sufficient transmission capacity is available to meet the plans and goals of the MISO membership over the next twenty years. This type of planning and implementation of cost-effective transmission capacity has the capability of mitigating the increased costs being incurred recently but take years, even exceeding a decade in some instances, to take effect. To address these increased costs on a more expedited basis, alternate approaches are required.
>
> **Near-Term Solutions**: Xcel Energy is currently piloting technologies commonly referred to as Grid Enhancing Technologies (GETs) that could provide some near-term relief to congestion issues. One such GET is "Smart Wires," a power control technology that can be utilized to alter the flow of power on the grid to avoid overloading certain facilities or lines. "LineVision" is another GET that can be utilized to monitor and help optimize transmission elements by allowing for the dynamic rating of

> limiting elements to take advantage of additional system capacity created by cooler temperatures or increased wind speeds. While these technologies can provide significant value, they are limited in their impact because they are designed only to optimize the existing system capability, not create new transmission system capacity. Xcel Energy has also developed and implemented a procedure in which system optimization (temporary reconfiguration) can be analyzed and implemented in a fair and equitable fashion to ensure the reliable delivery of energy to meet customer demand. The established process utilizes a publicly posted point of contact to allow stakeholders to submit requests for transmission system reconfigurations that will be analyzed in the order in which they are received. Requests are analyzed for impacts to system reliability, contractual constraints, and economic impacts. Those that are not found to have a negative impact are then coordinated with neighboring utilities and MISO, leading to reconfigurations being implemented to avoid or reduce system limitations that result in congestion costs.
>
> **Medium-Term Solutions**: To bridge the gap between the limits of GETs and long-term transmission expansion, Xcel Energy has also been undertaking efforts to identify low-cost, high-impact system upgrades to target the most impactful constraints resulting in increased costs. Project #19914 (High-Bridge – Rogers Lake Bifurcation to Double Circuit) and Project #20709 (Uprate Split Rock – White 345 kV) are two projects that have resulted from this analysis of low-cost, high-impact solutions that are projected to pay for themselves in congestion relief before a long-term solution planned at the same time could be placed in service. Additionally, any use or replacement of existing resource locations can leverage a robust system that has been designed to deliver energy to large areas of customer demand and reduce the risk of incurring additional congestion costs.
>
> **Going forward**: A regular long-range transmission planning process that holistically incorporates planned system changes not normally accounted for in regional planning efforts like MISO Transmission Expansion Plan (MTEP) can mitigate system limitations that cause large spikes in congestion costs before they become an issue. It can also identify areas in which incurring the congestion is the more cost-effective solution than the cost of transmission expansion. Such a regular planning effort combined with a fair and equitable process for reviewing options for increased system flexibility would provide powerful tools to avoid future spikes in congestion costs.

The Department appreciates Xcel's thorough response to our questions. Based on our review, the Department concludes Xcel reasonably explained its variance between actual and forecasted 2021 congestion costs. The Department will continue to monitor these costs, along with Xcel's efforts to mitigate these costs, in future FCA fillings.

c. Increased Fuel Costs for Gas Generation

Xcel provided the following table on page 9 of its Petition detailing its variance between actual and forecasted natural gas costs for Company-owned generation in 2021.

Figure 5: Company-Owned Natural Gas Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Gas (CC)	195,504	120,865	74,640	6,101	4,325	1,776	$32.05	$27.94	$4.10
Owned Gas (CT)	49,824	13,851	35,973	843	218	624	$59.13	$63.48	-$4.35

As shown in the above table, Xcel's actual natural gas costs for Company-owned generation was significantly higher than forecasted in 2021.

According to Xcel, its actual 2021 Company-owned natural gas generation was higher than forecasted due to higher LMPs and greater market sales, even though gas prices were higher than forecast. In addition, Xcel stated that gas prices were influenced by Winter Storm Uri in February and stayed elevated throughout most of the year. Xcel stated that since its fixed demand costs were spread over higher volumes, it resulted in a lower average $/MWh for Company-owned combustion turbines (CTs) - $59.13/MWh actual vs. $63.48/MWh forecasted.

Based on the above, the Department concludes Xcel reasonably explained its variance between actual and forecasted natural gas costs in 2021.

d. Increased Fuel Costs for Coal Generation

Xcel provided the following table on page 9 of its Petition detailing its variance between actual and forecasted coal costs for Company-owned generation in 2021.

Figure 3: Company-Owned Coal Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Coal	$197,754	$149,944	$47,810	9,265	7,022	2,243	$21.34	$21.35	-$0.01

Xcel stated that its actual coal generation was higher than forecast due to higher gas prices that led to stronger LMPs and greater market sales.

The Department agrees the majority of the variance between actual and forecasted coal costs appears to be due to increased generation rather than increased coal prices. As a result, the Department concludes Xcel has reasonably explained the variances between actual and forecasted coal costs in 2021.

e. Wind Curtailment

i. Costs

In accordance with several Commission Orders, Xcel provided its Wind Curtailment Report in Part C, Attachment 1 of its Petition. In addition, Xcel provided its actual 2021 wind curtailment MWh and costs for 2021 in the following table.

Table 6
2021 Wind Curtailment MWh and Costs

	MWh	Costs
Curtailment	926,013	$42,062,446

Xcel stated it was important to note the vast majority of the $42,062,446 in 2021 curtailment costs were associated with the contractual energy prices of its wind purchase power agreements (PPAs).[18] Xcel stated these are contractually obligated sunk costs (take or pay) which are not economically relevant to the decision to curtail the generation from a wind farm.[19]

Since the above table appears to include only curtailment costs associated with PPAs, the Department asked Xcel to provide the MWh and costs associated with curtailments for Company-owned wind farms in 2021. Xcel replied that Company-owned wind farms had curtailments totaling 605,997 MWh in 2021. [20] In addition, Xcel clarified it does not make curtailment payments for Company-owned wind farms.[21]

Based on the above, the Department notes that while Xcel's Company-owned wind farms do not have any direct curtailment costs associated with them, they do have a significant number of curtailment MWh in 2021. Taken together, the Department notes Xcel has total of 1,532,101[22] MWh of curtailment associated with all its wind projects (Company-owned and PPA) in 2021.

Xcel also stated it had typically broken up curtailment into two categories - Transmission Curtailment and Dispatchable Intermittent Resources (DIR). The Transmission Curtailment category specifically related to situations where local transmission-related outages impacted wind projects. The DIR category was considered curtailment not caused by local transmission outages, or where transmission

[18] Petition, Part C, Attachment 1, Page 7 of 15.
[19] Id.
[20] Per Xcel's Response to Department Information Request No. 16b. See Department Attachment 1 to these comments.
[21] Id.
[22] 926,013 + 605,997 = 1,532,010

outages did not impact a specific wind farm. Xcel stated the breakdown was informative when curtailment was primarily related to local transmission constraints on the Company's system. However, since curtailment is almost entirely related to regional transmission congestion on the MISO system, the Company stated it will longer provide a breakout for Transmission Curtailment. Instead, the Company stated it will refer to curtailment as "Economic Curtailment" or simply "Curtailment."

Regarding the Company's statement that curtailment is "almost entirely related to regional transmission congestion," and its proposal to eliminate the Transmission Curtailment category for local transmission-related outages and their impact on wind projects, the Department recommends that Xcel provide in reply comments its total 2021 curtailments in MWh for all wind projects (Company-owned and PPAs) due to local transmission-related congestion. The Department will make its final recommendation regarding Xcel's proposal to eliminate the Transmission Curtailment category after reviewing Xcel's reply comments.

The Department also asked Xcel to provide the curtailment costs included in its initial 2021 forecast. Xcel replied that its initial 2021 forecast included $11.2 million in curtailment costs for purchased wind generation. Xcel stated that, as it discussed in its Response to Department Information Request No. 16, no curtailment payments were included for Company-owned wind.[23]

The Department notes that Xcel's actual 2021 wind curtailment costs more than doubled from approximately $20 million in 2020 to $42 million in 2021. As a result, the Department asked Xcel to explain the significant year-over-year increase. Xcel replied:[24]

> As discussed in DOC IR No. 14 regarding congestion, the increased curtailment costs in 2020 compared to 2021 were the result of a number of different aspects of system operations, but a common factor is that the transmission system in the Upper Midwest has become oversubscribed and cannot support all the wind generation that has recently gone into service. Factors impacting 2021 curtailment were wind generation going into service prior to the completion of transmission upgrades required for the generation to interconnect along with a number of significant transmission outages. In other words, there was more wind generation installed in the western subregion of MISO than could be delivered to meet customer demand throughout the MISO footprint.

The Department also asked Xcel whether curtailments would continue into 2022 at similar levels. Xcel replied it anticipates wind generation curtailment would continue at levels comparable to 2021 since the conditions discussed in its Response to Department Information Request No. 17b are still

[23] Per Xcel's Response to Department Information Request No. 17. See Department Attachment 1 to these comments.
[24] Per Xcel's Response to Department Information Request No. 17b. See Department Attachment 1 to these comments.

present.[25] Moreover, Xcel stated that 2023 curtailments are even more uncertain since system conditions continue to evolve and wind generation is hard to predict.[26]

Finally, the Department asked Xcel to provide the amount of wind curtailment costs included in its 2022 FCA forecast. Xcel replied that it included $20.4 million in wind curtailment costs in its forecasted 2022 FCA for purchased wind.[27]

Based on the above, the Department concludes Xcel's wind curtailment costs have increased significantly in 2021 and are likely to remain high for the foreseeable future. In addition, the Department notes that Xcel may have significantly under forecasted its wind curtailment costs in its 2022 FCA in Docket No. E002/AA-21-295.

Based on the above, the Department concludes Xcel reasonably explained its variance between actual and forecasted wind curtailment costs in 2021. The Department will continue to monitor these costs in future FCA fillings.

ii. *Mitigation Efforts*

Xcel stated it has been working to schedule outages to minimize curtailment for a number of years by performing multiple outages at the same time and scheduling these activities during times when wind is normally at its lowest levels (typically summer). Xcel stated that while attempts to plan outage work with this principle in mind, it is not always possible. Moreover, Xcel stated summer months are also high load months and transmission outages may not be possible due to load serving needs.

Xcel stated it was also working to identify binding constraints that are likely to occur going forward and is developing plans to mitigate these constraints. Xcel stated its mitigation plans will be designed to cost effectively reduce both curtailment and congestion. Xcel stated its plans include breaker reconfiguration and transmission facility upgrades.

f. Summary

The Department reviewed Xcel's explanations for the variances between its actual and forecasted 2021 FCA retail sales and costs. Based on our review, the Department concludes Xcel has reasonably explained the differences between its actual and forecasted 2021 FCA retail sales and costs.

D. XCEL'S 2021 FUEL CLAUSE ADJUSTMENT TRUE-UP

In the instant Petition, Xcel requests approval to recover its 2021 under-collected fuel costs of $3.8 million from ratepayers. Xcel's 2021 true-up calculation, which shows how the Company arrived at the proposed refund amount, is summarized in the following table:

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[25] Per Xcel's Response to Department Information Request No. 17c. See Department Attachment 1 to these comments.
[26] Id.
[27] Per Xcel's Response to Department Information Request No. 17d. See Department Attachment 1 to these comments.

Department Table 3: Xcel's 2021 Fuel Clause Adjustment True-Up and Refund Amount - Minnesota Jurisdiction[28]

True-Up Component	*Amount*
Actual 2020 total FCA Costs	$894,089,000
Less: Recovered 2021 FCA Costs	$787,064,000
Less: Mid-Year Adjustment Collections	$1,188,000
Les: Over-recovery of 2020 True-Up	$124
Total 2021 FCA True-up Amount	$81,766,000

Xcel proposed to collect the $81.8 million true-up amount over a 12-month period beginning September 1, 2022. Xcel's proposed true-up factors by customer class for the month of September 2022 are as follows:

Department Table 4: Proposed True-Up Factors by Customer Class ($/kWh) September 2022[29]

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
Proposed True-Up	$0.00325	$0.00329	$0.00318	$0.00398	$0.00260	$0.00254
Approved Rate	$0.03328	$0.03369	$0.03265	$0.04081	$0.02671	$0.02609
Total September Rates	$0.03653	$0.03492	$0.03583	$0.04479	$0.02931	$0.02931

Xcel stated that to determine its proposed true-up factors by customer class, it compared 2021 forecasted Minnesota costs to actual costs, which included the mid-year rate adjustment as well as the 2020 over-recovered true up. Xcel stated the resulting amount, divided by twelve yields the average monthly recovered amount. The monthly amount is then divided by the forecasted Minnesota jurisdiction MWh sales subject to the Fuel Clause Adjustment, which yields the true-up per unit cost for each month. Xcel then multiplied the per unit cost by the Fuel Adjustment Factor (FAF) ratio to determine the proposed class true-up factors. Xcel stated that its proposed class true-up factors will be added to the monthly fuel cost charges for each of the 12 months beginning September 1, 2022.

Xcel's proposed tariff sheets reflecting the total proposed September 2022 rates are included in Part A, Attachment 9 of the Petition.

[28] Data in Department Table 3 retrieved from Petition at 4.
[29] Petition, Part A, Attachment 3.

Xcel also proposed to update the Company website with the true-up factors by August 1, 2022, or upon issuance of the Commission's Order, to provide customers 30 days' notice of the rate change. Xcel's monthly fuel rates are provided in the following link:

https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders

The Department reviewed Xcel's 2021 true-up calculations and resulting rate factors. Based on our review, the Department concludes Xcel's 2021 true-up calculations and resulting rate factors appear reasonable and recommends the Commission approve them.

E. COMPLIANCE WITH REPORTING REQUIREMENTS

The Department verified that the instant Petition included the information required per the following:

- Minnesota Rules 7825.2800 - 7825.2840, as revised on pages 3 - 4 and approved in Point 1 of the Commission's June 12, 2019 *Order* in Docket No. E999/CI-03-802.
- Annual FCA true-up general reporting guidelines, as outlined on page 7 and approved in Point 5 of the Commission's June 12, 2019 *Order* in Docket No. E999/CI-03-802.
- Annual FCA true-up reporting compliance matrix specific to Xcel, as shown in Attachment 3 of the March 1, 2019 joint comments and approved in Point 7 of the Commission's June 12, 2019 *Order* in Docket No. E999/CI-03-802.[30]

The Department performed a more detailed review of Xcel's Generation Maintenance Expenses and correlation to incremental forced outage costs compliance filing, as discussed below.

1. *Maintenance expenses of generation plants and correlation to incremental forced outage costs (IN THE MATTER OF THE REVIEW OF THE 2005 AAA OF CHARGES FOR ALL ELECTRIC UTILITIES, DOCKET NO. E999/AA-06-1208).*

In its February 6, 2008 Order in Docket No. E999/AA-06-1208 (06-1208 Order), the Commission required all electric utilities subject to automatic adjustment filing requirements, except for Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

This requirement stems from the drastic increase in IOUs' outage costs during FYE06 and FYE07. When a plant experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those market purchases flows through the FCA directly to ratepayers. The high level of outage costs in

[30] Point 7 of the Commission's June 12, 2019 *Order* in Docket No. E-999/CI-03-802 also stated that "each Electric Utility shall provide a complete analysis and discussion of the consequences of self-commitment and self-scheduling of their generators, including the annual difference between production costs and corresponding prevailing market prices." The Company provided this analysis and discussion in its March 1, 2021 filing in Docket No. E999/CI-19-704.

FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced (unplanned) outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates. The Commission agreed with the Department and the Large Power Intervenors that "utilities have a duty to minimize unplanned facility outages through adequate maintenance and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 06-1208 Order at 5.

The Department summarizes Xcel's generation maintenance spending in the following table:

Department Table 5: Comparison of Generation Maintenance Expense for Xcel ($ Millions)

Test Year	Approved Amount	Actual 2016-2021 Avg	Difference
2016	$184.7	$160.5[31]	$24.2

Because (1) the amount of generation maintenance expense is linked to a utility's forced (unplanned) outages, (2) utilities have an incentive to minimize generation maintenance expense between rate cases, and (3) utilities do not have a strong incentive to minimize the replacement power costs for which they receive flow through recovery, the Department intends to continue to monitor the difference between investor-owned utilities' actual and approved generation maintenance expenses in future FCA true-up filings.

The Department notes that Xcel's average maintenance spending for 2016-2021 was $160.5 million or 13.1 percent lower than the $184.7 million provided in Xcel's rates. As a result, the Department reviewed Xcel's incremental unplanned and planned outage costs for 2021 as reported in Part C, Attachment 5 of the Petition. As shown therein, Xcel's incremental unplanned outage costs were **[TRADE SECRET DATA HAS BEEN EXCISED]** than forecasted while its incremental planned outage costs were **[TRADE SECRET DATA HAS BEEN EXCISED]** than forecasted. As a result, the Department reviewed Xcel's outage information by unit included in Part C, Attachments 4 and 5. Based on our review, the Department concludes that Xcel reasonably explained its variances in 2021 outage costs.

The Department concludes Xcel's Petition complies with the applicable reporting requirements and recommends the Commission approve the compliance reporting portions of the Company's Petition.

[31] Xcel's actual generation maintenance expense was $187.8 million for 2016, $160.5 million for 2017, $173.4 million for 2018, $140.0 million for 2019, $150.8 million for 2020, and $150.4 million for 2021.

III. CONCLUSION AND RECOMMENDATIONS

Based on our review, the Department concludes that (1) Xcel's actual fuel/purchased power costs for 2021 were reasonable and prudent, (2) Xcel correctly calculated its 2021 true-up amount for under-recovered costs of $81.8 million and the resulting rate factors and recommends the Commission approve them, and (3) Xcel's Petition complies with the applicable reporting requirements. Therefore, the Department recommends the Commission take the following actions:

- Find Xcel's actual 2021 fuel/purchased power costs recoverable through the FCA rider were reasonable and prudent for 2021.

- Find Xcel correctly calculated its 2020 true-up amount for under-recovered costs of $81.8 million and the resulting rate factors.

- Approve the compliance reporting portions of Xcel's Petition.

In addition, the Department recommends Xcel provide in reply comments its total 2021 curtailments in MWh for all wind projects (Company-owned and PPAs) due to local transmission-related congestion. The Department will make its final recommendation regarding Xcel's proposal to eliminate the Transmission Curtailment category after reviewing Xcel's reply comments.

/ar

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Xcel Energy		Information Request No. 14
Docket No.:	E002/AA-20-417	
Response To:	Minnesota Department of Commerce	
Requestor:	Mark Johnson	
Date Received:	March 16, 2022	

Question:
Topic: MISO Congestion, FTR Charges, and ARRs
Reference(s): Petition at 13, Table 2

Xcel forecasted $33.2 million in MISO congestions costs for 2021 and $30.3 million in MISO FTR revenues for 2021. However, actual 2021 MISO congestion costs and FTR revenues totaled $230 million and $59.8 million, respectively.

a) Please explain if Xcel's MISO Auction Revenue Rights (ARRs) are included in the above referenced table. If not, please explain where these MISO charges can be found in Xcel's 2021 True-up Report. In addition, please provide Xcel's forecasted and actual MISO ARRs for 2021.

b) Please explain all the reasons for why MISO charges for congestion and FTRs were so high for 2021.

c) Does Xcel expect MISO charges for congestion and FTRs to be an ongoing problem and continue at 2021 levels in 2022 and 2023, or does Xcel expect this to be limited to 2021? Please explain.

d) MISO and the Organization of MISO States (OMS) are looking at FTR and ARR underfunding and concerns with participants not managing their exposure to congestion costs. Please explain what Xcel is doing to manage their exposure to congestion costs?

Response:

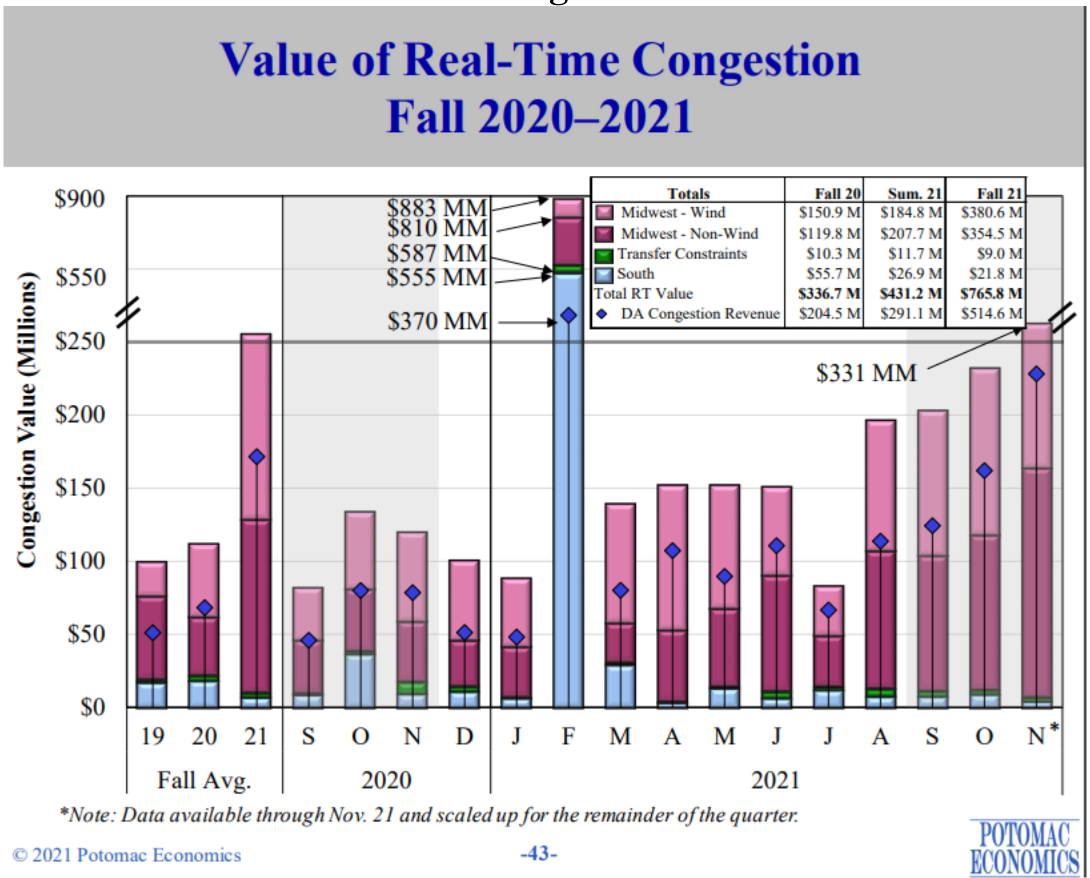
a) Xcel Energy's MISO Auction Revenue Rights (ARRs) are embedded in the above referenced table, since they are converted to Financial Transmission Rights (FTRs). ARRs are allocated to Market Participants based on firm historical usage of the transmission network during the MISO ARR Reference Year of March 2004 – February 2005. Xcel Energy converts all of these ARRs to FTRs. Participants that hold FTRs receive payment for congestion revenues on specific paths and these are frequently used to provide a financial hedge to manage the risk of congestion costs.

b) At a high level, congestion is caused by temporary mismatches between generation and available transmission. Congestion is relieved over time when new transmission investments are made. In the interim, the ARR/FTR market construct was developed to protect long-term, historical rights to the transmission system. However, this market has very limited provisions for incremental portfolio changes. Northern States Power Company is not entitled to ARRs or FTRs on transmission paths between new resources and our load, and the Company has limited options to mitigate congestion cost in the near term. At the same time, transmission congestion (and congestion cost) has increased as renewable resources have been built up across the MISO footprint. The combination of this development with limited offsetting ARRs or FTRs results in the Company being exposed to the costs of transmission congestion related to new resources in a way that it had not been previously.

   The MISO Independent Market Monitor (IMM) discussed the rise in congestion cost at the MISO Board Meeting on December 7, 2021.[1] The IMM presented Figure 1, below, representing the rise in congestion costs across the entire market. The three columns furthest to the left illustrate the significant rise in congestion costs between 2019 and 2021, and further, point to the role of wind generation in the Midwest as a key driver (as demonstrated by the significant increase in the "Midwest – Wind" light pink area of the column year over year).

[1] The IMM's entire presentation is available at: https://cdn.misoenergy.org/20211207%20Markets%20Committee%20of%20the%20BOD%20Item%2006%20IMM%20Quarterly%20Report608174.pdf

Figure 1



c) Congestion costs are inherent to the functioning of the MISO energy market, and the recent increase in congestion costs is more of a systemic than a singular change. Because we anticipate that congestion costs will persist, the Company is working to identify ways to mitigate these costs through transmission operation and expansion. As described below, the Company has several initiatives to address increased congestion costs.

d) The increased costs are impacted by many different aspects of system operations, but the common factor is that the transmission system in the Upper Midwest is oversubscribed and cannot support all the wind generation that has recently gone into service. Factors impacting congestion costs were wind generation going into service prior to the completion of transmission upgrades required for the generation to interconnect along with a number of significant transmission outages. In other words, there was more wind generation installed in the western subregion of MISO than can be delivered to meet customer demand throughout the MISO footprint. To address this common factor in the long term, a cost-effective plan for transmission expansion must be implemented. Below, we discuss the necessary long-term solutions, as well as near- and medium-term partial solutions to the problem.

Long-Term Solutions: The MISO Long Range Transmission Planning (LRTP) process is currently evaluating the type of cost-effective solutions to not just address existing limitations but ensure sufficient transmission capacity is available to meet the plans and goals of the MISO membership over the next twenty years. This type of planning and implementation of cost-effective transmission capacity has the capability of mitigating the increased costs being incurred recently but take years, even exceeding a decade in some instances, to take effect. To address these increased costs on a more expedited basis, alternate approaches are required.

Near-Term Solutions: Xcel Energy is currently piloting technologies commonly referred to as Grid Enhancing Technologies (GETs) that could provide some near-term relief to congestion issues. One such GET is "Smart Wires," a power control technology that can be utilized to alter the flow of power on the grid to avoid overloading certain facilities or lines. "LineVision" is another GET that can be utilized to monitor and help optimize transmission elements by allowing for the dynamic rating of limiting elements to take advantage of additional system capacity created by cooler temperatures or increased wind speeds. While these technologies can provide significant value, they are limited in their impact because they are designed only to optimize the existing system capability, not create new transmission system capacity. Xcel Energy has also developed and implemented a procedure in which system optimization (temporary reconfiguration) can be analyzed and implemented in a fair and equitable fashion to ensure the reliable delivery of energy to meet customer demand. The established process utilizes a publicly posted point of contact to allow stakeholders to submit requests for transmission system reconfigurations that will be analyzed in the order in which they are received. Requests are analyzed for impacts to system reliability, contractual constraints, and economic impacts. Those that are not found to have a negative impact are then coordinated with neighboring utilities and MISO, leading to reconfigurations being implemented to avoid or reduce system limitations that result in congestion costs.

Medium-Term Solutions: To bridge the gap between the limits of GETs and long-term transmission expansion, Xcel Energy has also been undertaking efforts to identify low-cost, high-impact system upgrades to target the most impactful constraints resulting in increased costs. Project #19914 (High-Bridge – Rogers Lake Bifurcation to Double Circuit) and Project #20709 (Uprate Split Rock – White 345 kV) are two projects that have resulted from this analysis of low-cost, high-impact solutions that are projected to pay for themselves in congestion relief before a long-term solution planned at the same time could be placed in service. Additionally, any use or replacement of existing resource locations can leverage a robust system that has been designed to deliver energy to large areas of customer demand and reduce the risk of incurring additional congestion costs.

Going forward: A regular long-range transmission planning process that holistically incorporates planned system changes not normally accounted for in regional planning efforts like MISO Transmission Expansion Plan (MTEP) can mitigate system limitations that cause large spikes in congestion costs before they become an issue. It can also identify areas in which incurring the congestion is the more cost-effective solution than the cost of transmission expansion. Such a regular planning effort combined with a fair and equitable process for reviewing options for increased system flexibility would provide powerful tools to avoid future spikes in congestion costs.

Preparer:	Carolyn Lee	Drew Siebenaler
Title:	Regulatory Consultant	Manager, Regional Transmission Planning
Department:	Commercial Operations	Transmission Regional Planning
Telephone:	303-571-7505	612-321-3195
Date:	March 28, 2022	

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Xcel Energy		Information Request No. 15
Docket No.:	E002/AA-20-417	
Response To:	Minnesota Department of Commerce	
Requestor:	Mark Johnson	
Date Received:	March 16, 2022	

Question:
Topic: MISO Congestion and FTRs for Wind Generation
Reference(s): Part B, Attachment 1, Page 13 of 13

(a) For each of the wind facilities listed in the above-referenced attachment, please explain why there are **[TRADE SECRET DATA BEGINS TRADE SECRE DATA ENDS].**

(b) Xcel stated on the above-referenced attachment that due to the limited amount of FTRs that MISO makes available to the Company, it does not fully cover the installed generator capacity to load node paths. Please explain why MISO has such a limited amount of FTRs and whether Xcel could purchase additional ARRs or do something else to mitigate or hedge the congestion costs associated with its wind facilities shown in the above-referenced attachment.

Response:

(a) The ARR/FTR market construct was developed to protect long-term, historical rights to the transmission system, and has very limited provisions for incremental portfolio changes. Northern States Power Company is not entitled to ARRs or FTRs on transmission paths between new resources and our load, and the Company has limited options to mitigate congestion cost without significant investment.

(b) ARRs are only allocated to market participants based on historical usage of the transmission network. FTRs are not limited by MISO; they are available for every transmission path in the MISO footprint. However, FTRs for paths between load and new generators are sold in an auction format, and the resulting sales prices have historically been quite high, as market participants have recognized the potential congestion revenues and factored this into their bids in the FTR auctions. Thus, there would be no expectation that the price paid for FTRs in an auction would be offset by the revenues they would provide. That said, Xcel Energy is carefully evaluating all options to mitigate congestion cost exposure for our customers and will bring forward cost-effective options for review, should we identify any.

Preparer:	Carolyn Lee
Title:	Regulatory Consultant
Department:	Commercial Operations
Telephone:	303-571-7505
Date:	March 28, 2022

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Xcel Energy		Information Request No. 16
Docket No.:	E002/AA-20-417	
Response To:	Minnesota Department of Commerce	
Requestor:	Mark Johnson	
Date Received:	March 16, 2022	

Question:
Topic: Wind Curtailment – Company Owned Wind
Reference(s): Petition at 7

Xcel stated that Company-owned wind production was less than forecasted primarily due to increased curtailments, which accounts for 60 percent of the decline. In addition, Xcel stated that Grand Meadows and Nobles wind facilities accounted for the majority of the curtailments.

a) Please provide the amount of wind curtailment costs for each Company-owned wind facilities in MWh and dollars that was included in Xcel's initial 2021 forecast.

b) Please provide the actual amount of wind curtailment costs for each Company-owned wind facilities in MWh and dollars for 2021.

c) Please provide actual wind curtailments for Grand Meadows and Nobles wind facilities in MWh and dollars for 2021.

d) Are the dollar amounts provided in Part (c) above included in Xcel's wind curtailment figure of $42,062,446 for 2021 as shown in Part C, Attachment 1, Page 7 of 15?

e) Please explain why Grand Meadows and Nobles wind facilities do not appear to be included in Xcel's Wind Curtailment Report shown in Part C, Attachment 2 of the Petition. Are any of the Company-owned wind facilities included in Xcel's Wind Curtailment Report shown in Part C, Attachment 2 of the Petition?

Response:

a) The Company does not make curtailment payments for Company-owned wind facilities in the manner that curtailment payments are made for PPA wind, so no comparable costs associated with Company-owned wind curtailment were included in the 2021 forecast.

b) The Company does not make curtailment payments for Company-owned wind facilities, so there are no curtailment payments for any Company-owned wind facility. Curtailment of Company-owned wind facilities in MWh in 2021 is shown below.

2021 Company-Owned Wind Curtailment	**MWh**
Blazing Star 1	9,283
Blazing Star 2	13,949
Border	226
Community Wind North	828
Courtenay	8,116
Crowned Ridge II	51,057
Foxtail	43,725
Freeborn	23,522
Grand Meadow	63,616
Jeffers	9,555
Lake Benton II (Buffalo Ridge / Chanarambie)	17,560
Mower County	8,826
Nobles	313,377
Pleasant Valley	42,356
Total	**605,997**

c) The Company does not make curtailment payments for Company-owned wind facilities, so there are no curtailment payments for the Grand Meadows or Nobles wind facilities. See part (b) above for the curtailment in MWh of the Grand Meadows and Nobles facilities in 2021.

d) The Company does not make curtailment payments for Company-owned wind facilities, so there are no actual curtailment payments for Company-owned wind facilities included in the total curtailment amount of $42,062,446.

e) We did not include the Grand Meadows, Nobles, or any other Company-owned wind facility in Part C, Attachment 2 of the Petition because there are no payments associated with curtailment at Company-owned wind facilities. As shown in part (b) above, we are able to provide curtailment volumes for Company-owned wind facilities, and will provide these in future fuel forecast annual true-up reports.

Preparer: Randy Oye
Title: Transmission Analyst
Department: Market Operations
Telephone: 612-330-2886
Date: March 28, 2022

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Xcel Energy		Information Request No. 17
Docket No.:	E002/AA-20-417	
Response To:	Minnesota Department of Commerce	
Requestor:	Mark Johnson	
Date Received:	March 16, 2022	

Question:
Topic: Wind Curtailment
Reference(s): Part C, Attachment 1, Page 7 of 15 and Page 14 of 15

a) Page 7 of the above-referenced attachment shows that Xcel's actual 2021 wind curtailment totaled 926,013 MWh or $42,062,446. Please provide the amount of wind curtailment MWhs and costs that was included in Xcel's initial 2021 forecast, including specific reference to Xcel's 2021 forecast.

b) Page 14 of the above-referenced attachment shows that Xcel's wind curtailment costs more than doubled from approximately $20 million in 2020 to $42 million in 2021. Please explain this significant year-over-year increase.

c) Does Xcel expect the same level of wind curtailments to occur in 2022 and 2023?

d) Please provide the amount of wind curtailment costs included in Xcel's 2022 FCA forecast in Docket No. E002/AA-21-295.

Response:

a) Wind curtailment costs included in the initial 2021 forecast were $11.2 million for purchased wind. As discussed in the response to Department of Commerce Information Request No. 16, no curtailment payments are included for Company-owned wind. Wind curtailment MWhs from the PLEXOS forecast are 50,988 MWh. This includes curtailment MWh included in the wind patterns input to PLEXOS in addition to curtailment MWhs forecast by PLEXOS.

b) As discussed in DOC IR No. 14 regarding congestion, the increased curtailment costs in 2020 compared to 2021 were the result of a number of different aspects of system operations, but a common factor is that the transmission system in the Upper Midwest has become oversubscribed and cannot support all the wind generation that has recently gone into service. Factors impacting 2021 curtailment were wind generation going into service prior to the completion of transmission upgrades required for the generation to interconnect along with a number of significant transmission outages. In other words, there was more wind generation installed in the western subregion of MISO than could be delivered to meet customer demand throughout the MISO footprint.

c) The Company anticipates that wind generation curtailment will continue into 2022 at levels comparable to what was experienced in 2021 since the conditions discussed in (b) above are still present. The 2023 curtailment is more uncertain since system conditions continue to evolve and wind generation development is hard to predict.

d) Wind curtailment cost included in the 2022 forecast were $20.4 million for purchased wind only. As discussed in the response to DOC IR No. 16, no curtailment payments are included for Company-owned wind.

Preparer:	Randy Oye	Mark Ritkouski
Title:	Transmission Analyst	Generation Modeling Analyst
Department:	Market Operations	Generation Modeling Services
Telephone:	612-330-2886	303-571-6320
Date:	March 28, 2022	

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. E002/AA-20-417

Dated this **13th** day of **April 2022**

/s/Sharon Ferguson

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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_20-417_AA-20-417
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_20-417_AA-20-417
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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_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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