MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	June 30, 2022	Agenda Item 4*
Company	Northern States Power Company d/b/a Xcel Energy	
Docket No.	**E-002/AA-20-417** **In the Matter of Xcel Energy's Petition for Approval of its 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges**	
Issue	Should the Commission approve Xcel's 2021 Fuel Adjustment Clause true-up?	

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✓ **Relevant Documents**	**Date**
Xcel Energy – True-Up Report (Public and Trade Secret)	March 1, 2022
Department of Commerce – Comments (Public and Trade Secret)	April 13, 2022
Xcel Energy – Reply Comments	May 2, 2022

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I. Statement of the Issue

Should the Commission approve Xcel's 2021 Fuel Adjustment Clause true-up?

II. Background

On March 1, 2022, Northern States Power Company d/b/a Xcel Energy (Xcel, NSP, the Company) made its Annual True-up Compliance Report for its 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges filing seeking recovery of $81.8 million.

On April 13, 2022, the Minnesota Department of Commerce – Division of Energy Resources (Department, DOC) filed comments recommending approval of Xcel's 2021 true-up petition (Petition).

On May 2, 2022, Xcel filed reply comments agreeing with the Department's recommendations.

III. Parties' Comments

A. Xcel Energy – True-Up Filing

As summarized in Table 1, Xcel stated that its actual fuel expense of $894.1 million was $144.3 million higher than the approved forecast of $749.7 million. Actual average fuel cost of $31.71/MWh was 14.1% higher than the authorized rate of $27.78MWh. However, actual fuel cost collections, once adjusted for a $25 million fuel cost increase implemented from October through December and the final 2020 fuel cost true-up implemented in September, resulted in under-collected fuel costs of $81.8 million.

Xcel indicated that significant drivers for differences between our 2021 forecast and actuals were:

- higher congestion cost from the MISO market than forecast;
- increased fuel cost for gas generation due to higher gas prices;
- increased fuel cost for coal generation in response to higher gas prices and resulting market Locational Marginal Prices (LMP).

Xcel also explained that the higher market LMPs also led to greater than forecast asset-based sales volumes and revenues, which also increased volume of generation from both gas and coal generators. Asset-based sales revenues served to offset some of the 2021 increased costs.

Table 1 - 2021 Fuel Cost and Revenue Comparison Summary, MN Jurisdiction

	Actual ($ in 000's)	Forecast ($ in 000's)	Variance ($ in 000's)	Variance (%)
Total FCA Costs	$894,089	$749,743	$144,346	19.3%
MWh Sales	28,195,869	26,988,067	1,207,801	4.5%
FCA Cost in $/MWh	$31.71	$27.78	$3.92	14.1%
Fuel Collections	$787,064	$749,743	$37,321	5.0%
Mid-Year Adjustment Collections	$25,135			
Over-recovery of 2020 True-Up	$124			
(Over) Under Recovery	$81,766			

Xcel explained that 2021 proved to be a challenging year for fuel recovery under the new fuel recovery mechanism. Beginning with Winter Storm Uri in February, and continuing throughout the year, pressures arose that led to significantly higher costs than forecast, and material under-recovery of fuel costs. NSP's diverse generation fleet allowed the Company to reliably navigate the Winter Storm Uri event and, through off-setting asset-based sales into MISO when LMPs were significantly elevated as a result of the storm, resulted in February costs being lower than forecast. However, following Uri, natural gas prices stayed higher than forecast throughout most of the year, leading to higher than forecasted fuel costs. As a result of high gas prices, coal generation ran more than forecast, and resulted in higher than forecast costs for coal generation. Additionally, late season coal prices began to rise significantly in response to high natural gas prices.

Congestion costs also drove costs higher than forecasted. Congestion costs saw a steep increase in April 2021, remained high through the summer of 2021, and saw another steep increase in September 2021 when gas prices rose to their highest level of the year. Although in-servicing of the new Huntley-Wilmarth transmission line provided some relief in December 2021, costs still remained much higher than those approved in this docket. MISO Congestion was high due to substantial renewable energy additions that have outpaced transmission capacity and limited the ability to transport lower-cost wind generation to MISO load zones. On-going transmission work to bring new lines into service and actions such as reconfigurations and dynamic line ratings may help mitigate some of the congestion in the near term. However, additional transmission investments will likely be necessary to address congestion over the longer term.

Throughout all these events, Xcel was able to manage its generation fleet successfully and reliably, including lower than forecasted nuclear forced outage rates. This led to substantial revenues from asset-based sales to MISO which significantly offset higher fuel and congestion costs.

Despite the $25.1 million in additional fuel surcharges implemented mid-year, year-end results still resulted in an $81.8 million under-collection. When the mid-year adjustment was implemented, the Company projected that year-end under-recovery of $70 million. Subsequently, September through December 2021 gas prices rose substantially, and congestion costs saw another steep increase in September 2021. This led to actual year-end costs being over $30 million higher than those estimated in August 2021.

1. Proposed True-Up Rate Factors

Xcel has proposed to collect the $81.8 million over the 12-month period starting on beginning September 1, 2022. Table 2 shows the proposed monthly adjustments by customer class.

Table 2 - Proposed Monthly True-Up Factors by Customer Class ($/kWh)[1]

	Residential	C&I, Non-Demand	C&I Demand, Non-TOD	C&I Demand, On-Peak	C&I Demand, Off-Peak	Outdoor Lighting
September 2022	$0.00325	$0.00329	$0.00318	$0.00398	$0.00260	$0.00254
October 2022	$0.00333	$0.00337	$0.00326	$0.00408	$0.00267	$0.00261
November 2022	$0.00340	$0.00344	$0.00333	$0.00417	$0.00273	$0.00266
December 2022	$0.00309	$0.00313	$0.00304	$0.00380	$0.00248	$0.00242
January 2023	$0.00304	$0.00308	$0.00299	$0.00373	$0.00244	$0.00238
February 2023	$0.00352	$0.00357	$0.00345	$0.00432	$0.00283	$0.00276
March 2023	$0.00310	$0.00314	$0.00305	$0.00381	$0.00249	$0.00243
April 2023	$0.00357	$0.00362	$0.00350	$0.00438	$0.00287	$0.00280
May 2023	$0.00335	$0.00339	$0.00328	$0.00411	$0.00269	$0.00262
June 2023	$0.00306	$0.00310	$0.00301	$0.00376	$0.00246	$0.00240
July 2023	$0.00266	$0.00269	$0.00261	$0.00326	$0.00213	$0.00208
August 2023	$0.00273	$0.00276	$0.00268	$0.00335	$0.00219	$0.00214

Xcel explained that the proposed class true up factors will be added to the approved monthly fuel cost charges for each of 12 months beginning September 1, 2022. Xcel provided the proposed tariff sheet reflecting the proposed true-up rates as Part A, Attachment 9. Because the tariff sheet presents calendar year 2022 rates, only the September through December 2022 rates are updated in the tariff to reflect our proposed true-up factors. Once its 2023 Fuel Forecast is approved,[2] the 2021 true-up factors will be added to the January through August 2023 tariff sheets.

Xcel proposed to update the Company web site with the true-up factors by August 1, 2022, or upon issuance of the Commission's Order and to provide customers 30 days' notice of the rate change. Monthly fuel rates are presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders.

2. Detailed Variance Explanations

a. Company-Owned Hydro Generation

The Company-owned hydro generation forecast was based on a 30-year annual historical average of hydro generation for NSP System plants. There is no fuel price input for hydro generation in the model because hydro generation does not require any fuel purchases.

[1] The true-up factor details are shown in Part A, Attachment 3 and Part A, Attachment 5

[2] Xcel's 2023 forecast was filed in Docket No. E-002/AA-22-179 and the Commission will take up that matter this fall.

Company-owned hydro facilities experienced lower than normal water flows in 2021, which resulted in less hydro generation than forecast and; therefore, higher generation from other fuel types. Table 3 compares Xcel's forecasted hydro to actuals.

Table 3 - Comparison, Forecasted Hydro to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Hydro	$0	$0	$0	7,264	8,125	(861)	$0.00	$0.00	$0.00

b. Company-Owned Wind Generation

Based on historical data, Xcel's wind generation forecast model incorporates individual hourly profiles of each Company-owned project with at least twelve months of operational data. For new projects that did not yet have annual data, the profiles were based on turbine technology, plant design, and localized weather data.

Actual 2021 Company-owned wind production was less than forecast primarily due to increased curtailment, which accounted for 60% of the decline. Post-PTC eligible facilities, Grand Meadow and Nobles, accounted for the majority of the curtailments. Also, in-service dates for Mower County and Freeborn wind facilities were later than forecast. There is no forecasted fuel price for wind generation because it does not require any fuel purchases. Less actual wind generation than forecast increased generation from other fuel types. Table 4 compares Xcel's forecasted Company-owned wind to actuals.

Table 4 - Comparison, Forecasted Company-Owned Wind to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Company-Owned Wind	$0	$0	$0	7,264	8,125	(860)	$0.00	$0.00	$0.00

c. Company-Owned Coal Generation

Forecasted coal prices are based on coal purchases under contract and rail contracts in effect at the time of filing. Any forecasted coal requirements that are not under contract are based on spot market prices. Based on capabilities of the individual plants, the coal forecast includes key modeling parameters, such as operating capacity and heat rate. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted coal rates.

Due to higher gas prices that led to stronger LMP and greater market sales, 2021 actual coal generation was greater than forecast. Table 5 compares Xcel's forecasted Company-owned coal to actuals.

Table 5 - Comparison, Forecasted Company-Owned Coal to Actuals

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

d. Company-Owned Wood/RDF Generation

Based on the individual plants' capabilities, the wood/refuse-derived fuel (RDF) forecast includes key modeling parameters, such as operating capacity and heat rate. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted wood/RDF rates. Actual 2021 Company-owned wood/RDF cost was less than forecast due to lower realized wood prices at Bayfront and French Island. Table 6 compares Xcel's forecasted Company-owned Wood/RDF to actuals.

Table 6 - Comparison, Forecasted Company-Owned Wood/RDF to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Company-Owned Wood/RDF	$9,155	$10,472	($1,318)	534	454	80	$17.15	$23.07	($5.92)

e. Company-Owned Natural Gas Generation

Based on the individual plants' capabilities, the Company-owned natural gas forecast includes key modeling parameters, such as operating capacity and heat rate. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted natural gas rates. For peaking plants, the model uses the MISO calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three-years of history. Natural gas fuel prices are forecast based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on transport and delivery contracts in place at the time the forecast filing was made.

Although gas prices were higher than forecast, actual 2021 Company-owned natural gas generation was higher than forecast due to stronger LMP and greater market sales. Influenced by Winter Storm Uri in February, gas prices stayed elevated throughout most of the year. The fixed gas demand costs were spread over greater volumes, which lowered the average $/MWh for the owned CTs, as seen in Table 7.

Table 7 - Comparison, Forecasted Company-Owned Natural Gas to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, 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)

f. Company-Owned Nuclear Generation

Based on the individual plants' capabilities, the Company-owned nuclear forecast includes key modeling parameters, such as monthly operating capacity. Planned maintenance for each unit and forced outage rates are based on historical data and expected conditions going forward. Forecasted nuclear fuel price is based on existing nuclear fuel contracts at the time the forecast was filed.

Due to a lower than forecast outage rate, actual Company-owned nuclear generation experienced better-than-forecast performance in 2021. Since January 2018 (through August 2021), Monticello has operated at an average capability factor of 94.2%, including 99.3% in 2018 and 98.6% in 2020, both non-refueling years. In that same timeframe, Prairie Island achieved a combined average capacity factor of more than 95%, including a 99.9% on Unit 2 in 2018; 99.4% on Unit 1 in 2019; and 99.3% on Unit 2 in 2020, all non-refueling years.[3] Table 8 compares Xcel's forecasted nuclear to actuals.

Table 8 - Comparison, Forecasted Company-Owned Nuclear to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Nuclear	$111,253	$111,986	($732)	14,069	13,744	324	$7.91	$8.15	($0.24)

g. Purchased Natural Gas Generation

Based on the individual plants' capabilities or according to terms specified in the individual Power Purchase Agreements (PPAs), the purchased natural gas forecast includes key modeling parameters, such as operating capacity and heat rate. Planned maintenance for each unit based on the overhaul schedule provided by the PPA counterparty, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted purchased natural gas rates.

Actual 2021 purchased natural gas generation was higher than forecast due to stronger LMP and greater market sales, even though gas prices were higher than forecast. Table 9 compares Xcel's forecasted natural gas to actuals.

[3] 2021 actual outage information for all facilities are found in Part C, Attachments 4 and 5 (trade secret).

Table 9 - Comparison, Forecasted Purchased Natural Gas to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Gas PPAs	$146,232	$83,784	$62,448	4,032	3,402	630	$36.27	$24.63	$11.64

h. Purchased Solar Generation (PPAs)

Each solar PPA is modeled in the forecast with hourly profiles for each project. These profiles are based on historical results from projects with operational data, and prices are based on the terms of each contract.

Actual 2021 purchased solar production volumes were lower than forecast due to higher curtailment at the Marshall facility. Purchased solar costs were higher due to greater generation than forecast for the Aurora and North Star facilities.[4] Table 10 compares Xcel's forecasted solar PPAs to actuals.

Table 10 - Comparison, Forecasted Solar PPAs to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Solar PPAs	$42,905	$40,172	$2,733	609	624	(15)	$70.47	$64.36	$6.10

i. Purchased Solar Generation (Community Solar Gardens)

The community solar gardens (CSG) program forecast includes expectations of future growth based on current applications for gardens seeking to participate in the program. Xcel identified current projects to anticipate in-service dates and estimate project completion (in capacity) by month and year. To help account for future projects, Xcel also forecasted additional applications based on a three-year historical average (removing outliers). The CSG program is modeled as one entity rather than individually by garden. The assumed price for the program is based on historical price data, incorporating the Applicable Retail Rate (ARR) and Value of Solar (VOS) vintage rates for projects forecasted to be in-service in 2021.

The market cost of energy from the solar gardens generation is based on the assumed Locational Marginal Price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers.

The 2021 actual CSG production and cost were slightly lower than forecast. The CSG forecast is based on assumptions of when community solar projects are completed (or receive permission to operate) and assumptions of how many under which rate vintages will operational during the forecast year. Completion dates can be impacted by weather, construction, and scheduling. All of these factors have an impact on the actual production and bill credits.[5] Table 11 compares Xcel's forecasted CSG to actuals.

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[4] See Part C, Attachment 7 for actual solar PPA production and cost by month and by contract.

[5] See Part C, Attachments 8-10 for more details about actual CGS above-market costs and total number

Table 11 - Comparison, Forecasted Community Solar Gardens to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
CSG Market	$73,006	$32,674	$40,332						
CSG Above Market	$110,646	$157,160	($46,514)						
Total CSG	$183,652	$189,834	($6,182)	1,456	1,467	(12)	$126.17	$129.36	($3.19)

j. Purchased Wind Generation

The wind PPA forecast reflects the hourly profiles for each individual project. For existing PPAs, profiles are based on historical data. For new PPAs, the profiles are based on turbine technology, plant design, and localized weather data. The price for each wind PPA is based on the terms of each contract. Projects for which the Company can allow MISO to curtail output are modeled as curtailable projects, using a 5-year historical average for curtailment costs. Those for which curtailment is not allowed are modeled as non-curtailable projects.

Due to higher wind curtailments, which accounted for 93% of the of the overall decline, actual purchased wind generation was less than forecast. Non-PTC eligible farms, such as Fenton and Minn Dakota, accounted for the majority of the actual wind curtailment. Actual costs compared favorably to forecast.[6] Table 12 compares Xcel's forecasted wind PPAs to actuals.

Table 12 - Comparison, Forecasted Wind PPAs to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Wind PPAs	$194,087	$194,502	($415)	5,008	5,934	(926)	$38.76	$32.78	$5.98

k. Purchased Generation – Other

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs, the remaining biomass PPA, and Manitoba Hydro's PPA) are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation.

Actual 2021 other purchased generation costs were lower than forecast due to lower generation volumes from a mix of small PPA contracts including KODA, Rapidan, SAF and City of St. Cloud. Table 13 compares Xcel's forecasted other PPAs to actuals.

of gardens and subscriptions.

[6] See Part C, Attachments 1 and 2 for greater detail on wind curtailment results.

Table 13 - Comparison, Forecasted Other PPAs to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance	2021 $/MWh, Actual	2021 $/MWh, Forecast	2021 $/MWh, Variance
Other PPAs	$176,450	$178,659	($2,209)	2,139	2,341	(202)	$82.51	$76.33	$6.18

I. Market Purchases and Sales

For forecasting purposes, the PLEXOS simulation can purchase energy from a simulated MISO market if that source of supply results in lower cost than utilization of one of Xcel's dispatchable resources. The simulation can make this decision hourly within the constraints of the modeled system. Additionally, the model forecasts monthly intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices designed to represent LMP for the NSP system. The sum of these quantities represents the equivalent MISO Day 2 and Day 3 forecasted costs.

Due to congestion and despite higher than forecast asset-based sales into MISO, net MISO revenue was lower than projected. Higher than forecast LMPs led to greater volume and revenue from asset-based sales, but these sales were made from higher cost generation due to higher fuel prices and limited ability to transport energy from the Company's renewable resources. Additionally, higher market LMPs resulted in greater costs for market purchases from MISO than forecast. Table 14 compares Xcel's forecasted net MISO to actuals and Table 15 compares Xcel's forecasted MISO charges by primary type.

Table 14 - Comparison, Forecasted Net MISO to Actuals

	2021 ($000), Actual	2021 ($000), Forecast	2021 ($000), Variance	2021 GWh, Actual	2021 GWh, Forecast	2021 GWh, Variance
Net MISO	($122,173)	($126,997)	$4,824	(10,574)	(7,267)	(3,307)

Also, Locational Marginal Prices (LMPs) were lower in 2021 than in 2019. MINN.HUB is a weighted average of price nodes in the northwest region of the MISO market, inclusive of Xcel's entire service territory. On average, LMPs at MINN.HUB for the day-ahead market were 22.6% lower in 2021 than in 2019. LMPs have a direct impact on the cost to purchase power to serve NSP load in the MISO market and lower LMPs result in lower market expenses to serve NSP load. However, lower LMPs also reduce the revenue NSP receives from short-term market sales, which also impacts final costs to its customers. Table 15 compares 2021 forecast to actuals by primary MISO charge type.[7]

[7] Xcel provided additional MISO charge details in Part B, Attachments 1-14. Additionally, Xcel discussed system congestion in Part B, Attachment 1 and within the wind curtailment report provided as Part C, Attachment 1

Table 15 - Comparison, Forecasted MISO Charge Types 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)
Total MISO Charges	$182,842	$239	$182,603

m. Retail Sales

Actual 2021 Minnesota retail sales of 28,814,203 MWh, when compared to forecasted sales of 27,384,049 MWh, resulted in an actual-to-forecast variance of 1,430,154 MWh.[8] Trade Secret Table 3 of Xcel's filing summarizes contributing factors to the forecast variance. Higher sales factors that include the following:

- greater than anticipated residential class COVID pandemic impacts from continued social distancing and work-from-home measures,
- the 2021 weather impact on sales,
- lower than expected Combined Heat and Power (CHP) generation, and other non-specified factors.

These were in part offset by the following:

- greater commercial and industrial (C&I) COVID pandemic impacts from reduced economic and business activity,
- lower than expected C&I load additions/reductions, and
- lower solar generation than forecasted.

In summary, the combined residential and C&I COVID pandemic impacts, weather impacts, and other non-specified factors were the largest contributors to the forecast variance.

3. Other Items Impacting Total Fuel Cost

a. Costs Excluded from Fuel Costs

Part A, Attachment 3 provides monthly details of the direct assigned WindSource and Renewable*Connect amounts for 2021, which are excluded from total fuel costs.

b. Solar Energy Standard Exclusion

The Commission's January 16, 2018 Order in Docket No. E-002/M-17-425 approved the Company's plan for crediting Solar Energy Standard (SES)-related costs back to SES-exempt customers and to annually recover this amount from the Company's customers through the

[8] Sales for the Renewable*Connect and the WindSource programs are excluded from these figures in the fuel clause mechanism.

riders through which solar costs are charged.[9] The (trade secret) 2020 annual FCA recovery is shown in Part A, Attachment 2, line 47, the month the excluded customers were issued their bill credit.[10] The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. Given its small amount, this charge was not included in the original forecast.

c. Saver's Switch Discount Recover

The Saver's Switch discount is applied during the months of June through September and; therefore, the 2021 true-up shows these amounts for those months in the detailed monthly actuals report shown in Part A, Attachment 2, line 48. The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. Given its small amount, this charge was not included in the original forecast.

d. Asset Based Margins

Table 16 shows that actual 2021 asset-based margins were $87.1 million higher than forecasted.

Table 16 - Actual 2021 Asset-Based Margins ($ millions)

	Revenue	Cost	Margin
Forecast	$136.3	$95.1	$41.2
Actuals	$437.2	$308.9	$128.3
Variance	($300.9)	($213.8)	($87.1)

4. Reporting in Compliance with Minnesota Rules and Other Compliance Items

Xcel provided information attesting to their compliance to the following:

- 7825.2800 Policies and Actions
- 7825.2810 Annual Report of Automatic Adjustment Charges
- 7825.2820 Annual Auditor's Report
- 7825.2830 Annual Five-Year Projection
- 7825.2840 Annual Notice of Reports Availability
- Other items in compliance with various Commission Orders in various dockets.

B. Department of Commerce – Comments

The 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.

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[9] The Fuel Clause Adjustment (FCA) and Renewable Development Fund (RDF) Riders.

[10] The Company provided this amount in its May 27, 2021 SES Annual Report filed in Docket No. E-999/M-17-425.

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

The Department noted that Xcel's actual 2021 fuel/purchased power costs were significantly higher than the forecasted costs that were approved by the Commission 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 amount of $81.8 million for the Minnesota jurisdiction.

As shown in Table 1 above, Xcel's 2021 MWh sales were 4.5% higher than forecasted and the Company's total system actual fuel/purchased power costs recoverable through the FCA for 2021 were about 19.3% higher than the forecasted 2021 costs. Overall, this results in a 14.1% increase in the average fuel/purchased power cost on a per MWh basis.

As summarized in the Table 17, 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.

Table 17 - Xcel's Forecasted and Actual 2021 FCA Cost Summary ($000's)

	2021 Actuals	2021 Forecast	Percentage Difference
Xcel's Generating Stations	$563,490	$407,117	38.4%
Plus: LT Purchased Energy	$559,674	$497,118	12.6%
Plus: LT CSG	$183,652	$189,834	-3.3%
Plus: ST Market Purchases	$315,027	$9,302	3286.7%
Total System Costs	**$1,621,843**	**$1,103,372**	**46.9%**
Less: Sales Revenues	($437,200)	($136,299)	220.8%
Less: CSG-AMC	($110,745)	($157,160)	-29.6%
Less: Windsource	($12,169)	($6,004)	102.7%
Less: Renewable Connect	($6,190)	($6,286)	-1.5%
Net System FCA Costs	**$1,055,539**	**$797,623**	**32.3%**
Total System Sales (MWh)	39,923,939	38,215,037	
Less: Windsource (MWh)	(440,556)	(212,927)	
Less: Renewable Connect (MWh)	(177,779)	(183,055)	
Net System Sales (MWh)	**39,305,604**	**37,819,056**	**3.9%**[11]
MN Jurisdictional Sales (MWh)	28,814,204	27,384,049	
Less: Windsource (MWh)	(440,556)	(212,927)	
Less: Renewable Connect (MWh)	(177,779)	(183,055)	

[11] Department Table 2 shows this difference to be (3.9%); however, this discrepancy does not affect any underlying totals.

	2021 Actuals	2021 Forecast	Percentage Difference
Net MN Sales (MWh)	**28,195,869**	**26,988,067**	**4.5%**
MN FCA Costs	$758,124	$569,448	33.1%
Add: CSG-AMC	$110,646	$157,160	-29.6%
Add: Laurentian Buyout	$13,192	$13,069	0.9%
Add: Pine Bend Buyout	$0	$0	0.0%
Add: Benson Buyout	$10,249	$10,066	1.8%
Other	$1,834	$0	0.0%
Net MN FCA Costs	**$894,089**	**$749,743**	**19.3%**
Net MN FCA Costs $/MWh	**$31.71**	**$27.78**	**14.1%**

2. Explanation of Variances

As mentioned above, the Department noted Xcel's above-mentioned explanations for the variances between its actual and forecasted 2021 fuel/purchased power costs and sales and discussed them as summarized below.

a. Retail Sales

The Department noted that contributing factors for actual sales being 1,430,154 megawatt hours (MWh) higher than forecasted included 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.

Based on its review, the Department concluded that Xcel has reasonably explained the differences between its actual and forecasted 2021 retail sales.

b. MISO Congestion Costs

Given the significant increases shown in Table 15 above, the Department asked Xcel several questions.

The Department, in Information Request (IR) No. 14a, asked Xcel 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 Financial Transmission Rights (FTRs). 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. Additionally, 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.[12]

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

> 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, since 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, the Department in IR No. 14d, asked Xcel to explain what the Company was doing to manage their exposure to congestion costs. Xcel replied:

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[12] A complete copy of Xcel's Response to Department IR No. 14 was provided in Attachment 1 of the Department's comments.

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.

Based on its review, the Department concluded that Xcel has reasonably explained the differences between its actual and forecasted 2021 congestion costs. In future FCA fillings, the Department will also continue to monitor these costs, along with Xcel's efforts to mitigate them.

c. Increased Fuel Costs for Gas Generation

The Department noted that Xcel's 2021 actual natural gas costs for Company-owned generation was significantly higher than forecasted; however, based on its review, the Department concluded that Xcel has reasonably explained the reasons for the variance.

d. Increased Fuel Costs for Coal Generation

The Department agreed that 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 concluded that Xcel has reasonably explained the reasons for the 2021 variance between actual and forecasted coal costs.

e. Wind Curtailment Costs

As shown in Table 18, Xcel's 2021 926,013 MWh wind curtailment cost $42,062,446. Xcel stated it was important to note the vast majority of these costs were associated with the contractual energy prices of its wind purchase power agreements (PPAs). 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.[13]

Table 18 – 2021 Wind Curtailment MWh and Costs

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

[13] Petition, Part C, Attachment 1, Page 7 of 15.

Since Table 18 appears to only include curtailment costs associated with PPAs, the Department asked Xcel to provide its 2021 MWh and costs associated with curtailments for Company-owned wind farms. Xcel replied that 2021 Company-owned wind farms' curtailments were 605,997 MWh and clarified that the Company does not make curtailment payments for Company-owned wind farms.[14] Based on Xcel's response, the Department noted that Xcel had a total of 1,532,101[15] MWh curtailed 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 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." As a result, the Department recommended that, in reply comments, Xcel provide 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.

Since Xcel's actual 2021 wind curtailment costs more than doubled from approximately $20 million in 2020 to $42 million in 2021, the Department, in IR No. 17b[16] asked Xcel to explain the significant year-over-year increase. Xcel replied:

> 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 confirmed that Xcel anticipates 2022 curtailment levels[17] to continue at similar levels and that 2023 curtailments are even more uncertain since system conditions continue to evolve and wind generation is hard to predict.

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[14] See Department Attachment 1 – Xcel's response to Department IR No. 16b.

[15] 926,013 + 605,997 = 1,532,010

[16] See Department Attachment 1 – Xcel's response to Department IR No. 17b.

[17] The Department noted that 2022's curtailment forecast was $20.4 million.

Based on the above, the Department concluded that Xcel's wind curtailment costs have increased significantly in 2021 and are likely to remain high for the foreseeable future. Additionally, the Department noted that Xcel may have significantly under-forecasted its 2022 wind curtailment FCA costs in Docket No. E-002/AA-21-295 (21-295).

The Department concluded Xcel reasonably explained its variance between actual and forecasted wind curtailment costs in 2021 and will continue to monitor these costs in future FCA fillings.

3. Xcel's 2021 Fuel Clause Adjustment True-Up

The Department reviewed Xcel's 2021 true-up calculations and resulting rate factors and, based on its review, the Department concluded that Xcel's 2021 true-up calculations and resulting rate factors appear reasonable and recommended that they be approved.

4. Compliance with Reporting Requirements

The Department verified that Xcel's 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. E-999/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. E-999/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. E-999/CI-03-802.

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

In its February 6, 2008 Order in Docket No. E-999/AA-06-1208 (06-1208 Order), the Commission required all electric utilities subject to automatic adjustment filing requirements, with the exception of 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 Investor-Owned Utilities' (IOUs) outage costs during FYE06 and FYE07. When a plant experiences a forced outage, the utility must replace, usually through wholesale market purchases, the megawatt hours that plant would have produced had it been operating. The cost of those market purchases flows through the FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced 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 Interveners 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)

In Table 19, the Department summarized Xcel's maintenance spending.

Table 19 – Comparison of Generation Maintenance Expense for Xcel ($ Millions)

Test Year	Approved Amount	Actual 2016-2021 Avg	Difference
2016	$184.7	$160.5[18]	$24.2

The Department noted that, 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, it 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 noted that Xcel's average maintenance spending for 2016-2021 was $160.5 million or 13.1% lower than the $184.7 million provided in Xcel's rates. As a result, the Department reviewed Xcel's incremental forced outage costs for 2021 as reported in Part C, Attachment 5 of the Petition and concluded that Xcel has reasonable explained its 2021 outage costs variance.

5. Conclusion and Recommendations

Based on its review, the Department concluded 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 recommended that the Commission approve them, and (3) Xcel's Petition complies with the applicable reporting requirements. Therefore, the Department recommended that the Commission take the following actions:

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

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

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

C. Xcel Energy – Reply Comments

Xcel acknowledged that, while Transmission Curtailment has been declining over the past number of years, the Company overstated how it intends to report on curtailment in future reports and, instead, should have said that it would not report those costs in years where the Transmission Curtailment costs is relatively small compared to DIR Curtailment. To prevent confusion related to this issue, Xcel confirmed that it will provide a full breakdown between the curtailment categories in future reports.

Also, as shown in Table 20, Xcel provided the total 2021 curtailment in MWh for all wind Company-owned and PPA wind projects due to transmission-related congestion in comparison to the amount of curtailment due to DIR-related curtailment.

Table 20 – 2021 Wind Curtailment (MWh)

	Transmission	DIR	Total
Company-Owned	17,034	589,196	606,230
PPA	16,468	909,545	926,013
Total	33,502	1,498,741	1,532,243

IV.Staff Comments

Staff has reviewed and verified Xcel's calculations and concurs with the Company and the Department's recommendations that Xcel's Petition be approved as filed.

Staff notes that the Department's conclusion that Xcel may have significantly under-forecasted its 2022 wind curtailment FCA costs in 21-295 seems to be correct. Approximately two weeks after the Department's comments were filed in this docket, Xcel filed a request in 21-295 to implement an upward adjustment to the 2022 FCA costs. In that filing, Xcel provided a comparison between approved 2022 FCA costs and its revised cost forecasts.[19] The two main drivers for the increase request are higher gas prices and higher congestion costs. Since higher congestion costs are generally translate to higher curtailment costs, Staff concurs with the Department's conclusion that 2022 curtailment costs were probably under-forecasted.

Finally, Staff points out that, in reply comments, Xcel agreed to continue providing the curtailment costs breakdown that the Department raised as an issue. Based on Xcel's response, Staff considers the issue to be resolved and confirmed that with the Department that they agree with that assessment. However, during the hearing, the Commission may want to ask the Department to confirm that they still agree.

[19] See (Trade Secret) Table 2 in Xcel Energy's May 19, 2022 Adjustment Proposal in Docket No. E-002/AA-21-295.

V. Decision Alternatives

Fuel Adjustment Clause True-Up Compliance Filing

1. Accept and approve Xcel's 2021 Fuel Adjustment Clause true-up compliance filing. (Xcel, DOC)

2. Do not accept and approve Xcel's 2021 Fuel Adjustment Clause true-up compliance filing.

True-Up Amount

3. Authorize Xcel to recover the 2021 under-collection of $81.8 million. (Xcel, DOC)

4. Authorize Xcel to recover a different amount.

Tariff Sheets

5. Approve Xcel's proposed tariff sheets. (Xcel, DOC)

6. Do not approve Xcel's proposed tariff sheets.