# STAFF MEMORANDUM

**TO:** COMMISSIONERS AND ADVISORS

**FROM:** BRITTANY MEHLHAFF, PATRICK STEFFENSEN, AND KRISTEN EDWARDS

**RE:** EL22-026 - In the Matter of the Petition of Northern States Power Company dba Xcel Energy for Approval of its 2023 Infrastructure Rider Project Eligibility and Factor Update

**DATE:** December 2, 2022

## BACKGROUND

On September 30, 2022, the South Dakota Public Utilities Commission (Commission) received a petition from Northern States Power Company dba Xcel Energy (Xcel or Company) for approval of its 2023 Infrastructure Rider Project Eligibility and Factor Update.

The Infrastructure Rider was established in Docket EL12-046 and was revised in Docket EL14-058 to require annual Commission-approved filings. Since then, the Company has made annual filings requesting approval of revenue requirements, project eligibility, and rates. The Infrastructure Rider is based on estimated costs of the capital projects subject to annual true-up to their actual costs and recoveries. The Infrastructure Rider was last updated in Docket EL21-028, with rates effective January 1, 2022.

In this current filing, Xcel requests the Commission's approval of the Infrastructure Rider Tracker Report and true-up for the 2022 revenue requirement, and 2023 Infrastructure rider revenue requirements of approximately negative $2.3 million. This represents a substantial decrease to the revenue requirements approved in prior infrastructure rider dockets, as Xcel is proposing to transfer recovery of all projects currently recovered in the infrastructure rider to base rates in the current rate case proceeding, Docket EL22-017. Thus, the 2023 revenue requirement is solely the true-up of the remaining over-recovery to be returned to ratepayers. In its rate case, Xcel states this roll-in of infrastructure rider projects represents approximately $33.8 million[1] in revenue requirements.

The Company proposed to revise the Infrastructure Rider Adjustment Factor from the current rate of $0.013361 per kWh to negative $0.001037 per kWh, effective January 1, 2023. Xcel estimates the average bill impact for a typical residential customer using 750 kWh per month to be negative $0.78 per month, a decrease of $10.80 per month compared to 2022 bill impacts.

Staff's recommendation is based on its analysis of Xcel's filing, discovery information, relevant statutes, and previous Commission orders. Staff reviewed updates regarding previously approved projects, the

[1] Refer to EL22-017 Halama Direct, page 59, Table 6.

2022 tracker report, the forecasted 2023 revenue requirement, and rate calculations. No new projects are being proposed at this time.

## EXISTING PROJECT UPDATES

Two wind projects were approved for inclusion in the Infrastructure Rider in Dockets EL20-026 and EL21-028 with projected in-service dates in 2021 and 2022. Updates regarding these wind projects are discussed below.

**Dakota Range I and II** – The Dakota Range I & II (Dakota Range) project was approved in Docket EL20-026 and is a 302.4 MW self-build wind project located 20 miles north of Watertown, South Dakota. In Docket EL18-003, the Commission granted a permit to construct the wind facility on July 23, 2018 and granted the transfer of the permit to Xcel on March 9, 2020. The project achieved commercial operation in January 2022.

Xcel reports that the recently passed Inflation Reduction Act of 2022 (IRA) increased the PTC credit for projects placed in-service in 2022 from $26.00 to $27.50, and the Dakota Range I and II project will receive PTCs with this higher value as a result. While the additional PTCs will result in significant benefits for customers, ongoing supply chain issues contributed to an increase in capital costs for the project. However, the 2022 revenue requirements were still less than projected in last year's filing.

**Northern Wind** – Changes in production levels, supply chain issues, and inflationary pressures impacted Xcel's acquisition of this project. However, the Company was able to renegotiate the terms of the transaction in order to achieve commercial operation at essentially the same cost to customers. Xcel expects the project to achieve the full PTC credit and the passage of the IRA further reduced the expected cost.

The above projects are proposed to be recovered in base rates beginning January 1, 2023, as part of the Company's current rate case proceeding, Docket EL22-017. Therefore, no costs are included in the Infrastructure Rider beginning January 1, 2023.

## 2022 TRACKER REPORT

The Infrastructure Rider rate approved in Docket EL21-028 was based on the estimated 2022 revenue requirements associated with 76 approved projects. In this docket, Staff reviewed the initially filed 2022 project revenue requirement of $31,314,952 to determine if the costs were prudent and at the lowest reasonable cost to ratepayers. As described in the Company's initial petition, the 2022 forecast for projects in the Infrastructure Rider is $575,897 less at this time compared to the estimate provided in Docket EL21-028.

The settlement approved in the Company's last rate case, Docket EL14-058, approved a methodology of applying a carrying charge to each individual monthly over/under balance instead of a running over/under balance. In recognition of the discrepancy with how it is calculated in the Transmission Cost Recovery Rider, Xcel will begin applying the carrying charge to the running over/under balance, effective the beginning of 2022. The Company's initial filing estimated a 2022 over-collection of $2,262,749, including carrying charges.

While analyzing the workpapers[2], it was discovered there was an error in the calculation of the Benson Biomass project revenue requirement for 2021 and 2022, where too much O&M expense was included in the revenue requirements. This error was corrected in Xcel's updated filing on November 29, 2022. Xcel explained the error was due to a mismatch between how the Benson Biomass buyout was being handled in the Infrastructure Rider versus another internal model and a transposition of two rows of data within the Infrastructure Rider model.

This correction decreases the 2021 project revenue requirement by $60,570 (from $25,542,854 to $25,482,284) and decreases the 2022 project revenue requirement by $68,444 (from $31,314,952 to $31,246,508), as shown on Updated Attachment 2.

Using Updated Attachment 4, the 2022 forecast for projects in the Infrastructure Rider is $644,341 less at this time compared to the estimate provided in Docket EL21-028.

The correction then provides a revised 2022 overcollection of $2,400,533, including updated carrying charges, as shown on Updated Attachment 2.

## 2023 INFRASTRUCTURE RIDER REVENUE REQUIREMENT

Xcel's initial petition proposed a 2023 revenue requirement of negative $2,262,749, consisting of only the proposed 2022 over-collection. Revenue recovery of approximately $33.8 million for the 76 previously-approved projects is pending base rate recovery in rate case Docket EL22-017.

The updated filing to correct the Benson Biomass project revenue requirements decreases this overall revenue requirement by $137,784 to negative $2,400,533, as shown on Updated Attachment 2.

## 2023 INFRASTRUCTURE RIDER ADJUSTMENT FACTOR

The Infrastructure Rider rate is designed to be implemented effective January 1, 2023. The rate is calculated based on forecasted sales from January 2023 through December 2023. The Infrastructure Rider rate based on the corrected 2023 estimate of overall revenue requirements of negative $2,400,533 is negative $0.001100 per kWh, as shown on Updated Attachment 1. The corrected average residential bill impact of the 2023 Infrastructure Rider is negative $0.83 per month, a decrease of $10.85 per month compared to the average residential bill impact of the 2022 Infrastructure Rider of $10.02 per month.

## ANNUAL REPORT ON WIND PROJECTS PERFORMANCE

In past rate case and infrastructure rider dockets, Xcel agreed to report information related to capital costs, operating costs, and plant performance for the Pleasant Valley, Border, Courtenay, Blazing Star I,

[2] Xcel Response to Staff DR 1-5

Crowned Ridge II, Foxtail, Lake Benton, Blazing Star II, Freeborn, Dakota Range I & II, Jeffers, Community Wind North, Mower, Northern Wind, and Noble Wind Repower projects once completed and in-service, so that Staff may assess the actual economics of the projects.

Xcel provided the Wind Project Performance Annual Report information for calendar year 2021 in Attachment 12 for Pleasant Valley, Border, Courtenay, Foxtail, Lake Benton, Blazing Star I, Crowned Ridge II, Blazing Star II, Freeborn, Jeffers, Community Wind North, and Mower, as these were the projects placed in-service by the end of 2021. Xcel agrees to provide this information for Dakota Range I & II, Northern Wind, and Nobles Wind Repower in subsequent infrastructure rider filings.

Pleasant Valley has an operating capacity of 200 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $331.8 million through 2021. The actual costs were below the original forecasted costs of $342.9 million. For 2021, Pleasant Valley produced 725,718,700 kWh of gross energy and had a net production of 707,869,757 kWh, had 38,466,394 kWh in total curtailment, and an average annual capacity factor of 41.3%.

Borders Wind has an operating capacity of 150 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $261.6 million through 2021. The actual costs were slightly less than the original forecasted costs of $261.8 million. For 2021, Border Wind produced 643,631,200 kWh of gross energy and had a net production of 633,767,011 kWh, had 233,400 kWh in total curtailment, and an average annual capacity factor of 48.9%.

Courtenay Wind has an operating capacity of 200 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $289.9 million through 2021. The actual costs were below the original forecasted costs of $300 million. For 2021, Courtenay Wind produced 764,141,400 kWh of gross energy and had a net production of 743,840,123 kWh, had 8,102,978 kWh in total curtailment, and a capacity factor of 44.6%.

Foxtail has an operating capacity of 150 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $230.2 million through 2021. The actual costs were below the original forecasted costs of $242.4 million. For 2021, Foxtail produced 631,753,739 kWh of gross energy, had a net production of 621,045,791 kWh, had 43,725,300 kWh in total curtailment, and a capacity factor of 47.3%.

Lake Benton has an operating capacity of 100 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $157.1 million through 2021. The actual costs were below the original forecasted costs of $166.7 million. For 2021, Lake Benton produced 443,832,683 kWh of gross energy and had a net production of 440,860,650 kWh, had 18,112,894 kWh in total curtailment, and a capacity factor of 50.9%.

Blazing Star I has an operating capacity of 200 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $315.6 million through 2021. The actual costs were below the original forecasted costs of $318.8 million. For 2021, Blazing Star I produced 818,444,166 kWh of gross energy and had a net production of 804,637,589 kWh, had 9,335,427 kWh in total curtailment, and a capacity factor of 45.9%.

Crowned Ridge II has an operating capacity of 200 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $299.8 million through 2021. The actual costs were below the original forecasted costs of $315.4 million. For 2021, Crowned Ridge II produced 839,436,739 kWh of gross energy and had a net production of 821,985,916 kWh, had 51,152,873 kWh in total curtailment, and a capacity factor of 48.8%.

Blazing Star II has an operating capacity of 200 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $342.5 million through 2021. The actual costs were above the original forecasted costs of $320.2 million. For 2021, Blazing Star II produced 761,743,637 kWh of gross energy and had a net production of 739,612,360 kWh, had 13,948,554 kWh in total curtailment, and a capacity factor of 46.1%.

Freeborn has an operating capacity of 200 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $317.9 million through 2021. The actual costs were above the original forecasted costs of $285.0 million. For May through December 2021, Freeborn produced 398,615,250 kWh of gross energy and had a net production of 388,913,237 kWh, had 23,523,292 kWh in total curtailment, and a capacity factor of 37.1%.

Jeffers has an operating capacity of 44 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $72.0 million through 2021. The actual costs were above the original forecasted costs of $71.8 million. For 2021, Jeffers produced 176,454,870 kWh of gross energy and had a net production of 173,302,000 kWh, had 9,471,877 kWh in total curtailment, and a capacity factor of 45.8%.

Community Wind North has an operating capacity of 26.4 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $66.5 million through 2021. The actual costs were above the original forecasted costs of $66.3 million. For 2021, Community Wind North produced 108,050,958 kWh of gross energy and had a net production of 106,069,563 kWh, had 818,002 kWh in total curtailment, and a capacity factor of 46.6%.

Mower has an operating capacity of 98.9 MW and has a total capital cost to build the facility, including transmission, but excluding AFUDC, of $158.3 million through 2021. The actual costs were below the original forecasted costs of $168.3 million. For March through December 2021, Mower produced 226,186,509 kWh of gross energy and had a net production of 222,070,060 kWh, had 9,703,900 kWh in total curtailment, and a capacity factor of 36.2%.

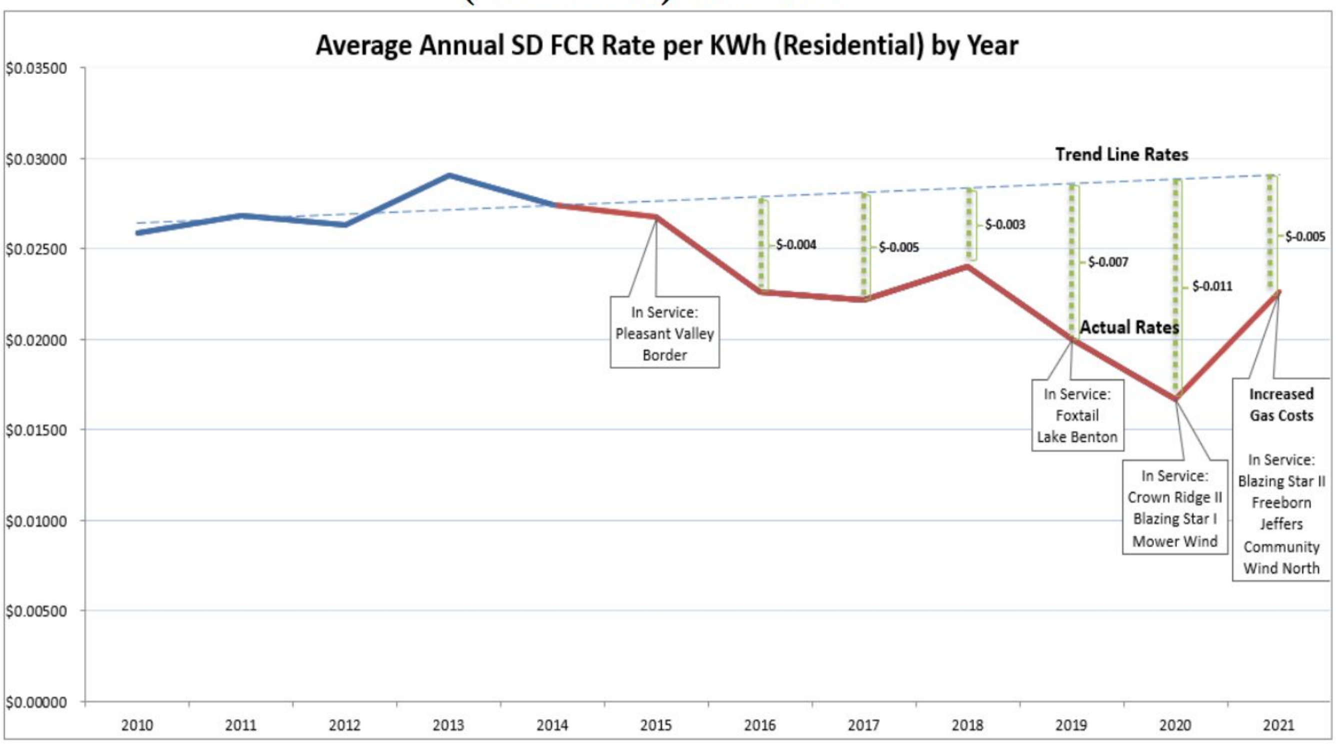
## NET WIND BENEFITS

### Bill Comparisons With and Without Wind Projects

Wind investments owned by Xcel ultimately decrease the costs that get recovered in the fuel clause, but it is difficult to calculate a snapshot of the net benefits provided to customers by Xcel's wind facilities at a given point in time. It is still important to analyze whether the benefits provided to customers in the form of decreased fuel costs outweighs the cost of the wind facilities passed on to customers in the infrastructure rider when analyzing whether to add new wind projects to the rider. Thus, the following exercise has been performed to show estimates of a bill comparison with and without the wind projects currently in the infrastructure rider.

First, Xcel provided[3] the following trendline analysis that shows in the period from 2010 to 2015, prior to the addition of most of Xcel's major wind resources, the fuel clause rate was on an upward trend. This chart compares the actual fuel clause rates (solid line) with what the rates would've been had the 2010 through 2015 trend continued (dashed line).

**Figure 1: Average Annual SD FCC Rate per kWh (Residential) 2010-2021**




Xcel estimates[4] this to be a difference of approximately $0.01072 per kWh for 2020. For a typical residential customer using 750 kWh per month, this represents a fuel clause savings of approximately $8.04 per month in 2020. While fuel clause rates did rise again in 2021, primarily due to an increase in gas costs, fuel clause rates were still below what the rates would have been had the 2010 through 2015 trend continued. Xcel estimates the difference for 2021 to be approximately $0.00506 per kWh[5],

[3] Petition, page 17 – Figure 1.

[4] Xcel Response to Staff DR 2-16 in Docket EL21-028. (Note: This amount was rounded to $0.011 in Figure 1 and rounded to $0.01 on page 17 of the Petition)

[5] Xcel Response to Staff DR 2-16 in Docket EL21-028. (Note: This amount was rounded to $0.005 in Figure 1 and page 17 of the Petition)

representing a fuel clause savings of approximately $3.79 per month in 2021 for a typical residential customer using 750 kWh per month.

Backing the wind costs out of the infrastructure rider rate that was in effect in 2020 and 2021 shows that customers were charged $3.87 per month in 2020 and $6.19 per month in 2021 for Xcel's wind investments. Thus, given this bill comparison exercise, customers saved $4.17 per month on their total bill in 2020 and experienced a net cost of $2.40 per month in 2021.

Xcel also performed a similar analysis for 2022 to-date[6]. Based on the year-to-date average fuel clause rate for residential customers of $0.02394/kWh, the current difference between the fuel clause rate and the 2010-2015 trend is a savings of $0.00544, or approximately $4.08 per month for a typical residential customer using 750 kWh per month. The wind costs portion of the infrastructure rider rate in 2022 was $8.52 per month[7]. When compared against the fuel clause savings to-date in 2022, customers experienced a net cost of $4.44 per month.

It should be noted that changes in commodity prices likely also played a role in the decrease in actual fuel costs from 2015 to 2020. That exact number is difficult to calculate, since we do not know which generation facilities would've been dispatched under varying commodity costs. However, commodity costs have been relatively stable over the last decade up until 2021. While fuel costs increased in 2021 largely due to the increase in gas commodity costs, Xcel states that the wind generation provides a hedge against fuel costs and helps to keep fuel costs lower than they would have been without the wind additions.

Given the timing issues at play with the various moving parts in the fuel clause and varying in-service dates of the wind projects, it can be expected there might be some years that show a net cost in this simplified analysis, such has occurred in 2021 and 2022. However, wind investments are expected to provide net ratepayer benefits in the long term. It should also be noted, the revenue requirements for each of the wind facilities will continue to change over time, and there will be countering impacts of accumulated depreciation decreasing the revenue requirements while expiring PTCs result in increases in the fuel clause.

Xcel provided additional support[8] by comparing the historical average "all-in" residential electric rate, including all base, riders, and fuel clause rates, per year, and compared the 2016-2021 trend to the 2010-2015 trend. The Company maintains this analysis demonstrates that since the trend from 2016-2021 is lower than the trend from 2010-2015, the Company's wind additions have driven lower overall energy costs.

[6] Xcel Response to Staff DR 1-4
[7] It is important to note that the carryover balance in 2022 of approximately $1.03 per month is mostly attributable to the wind projects, which would reduce the residential bill impact per month associated with the wind projects.
[8] Refer to Petition, pages 17-18 and Figure 2.

Since Xcel proposed that future recovery of these wind projects be in base rates, and project costs are proposed to be excluded from the Infrastructure Rider beginning January 1, 2023, any further analysis of these projects will take place in the pending rate case.

## RECOMMENDATION

Staff recommends the Commission approve the revised Infrastructure Rider Adjustment Factor of negative $.001100 per kWh and tariff sheet effective January 1, 2023.