



414 Nicollet Mall  
Minneapolis, Minnesota 55401

August 31, 2021

— Via Electronic Filing —

Steve Kahl, Executive Secretary  
North Dakota Public Service Commission  
State Capitol, 600 East Boulevard  
Bismarck, ND 58505-0480

**Re: September 2021 Fuel Cost Rider Rates  
Case No. PU-21-012**

Dear Mr. Kahl:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric Fuel Cost Rider (FCR) rates for September 2021.

The table below shows the FCR rates by customer class:

| September 2021                      | FCR rate/kWh |
|-------------------------------------|--------------|
| Residential                         | \$0.03484    |
| C & I Non-Demand                    | \$0.03606    |
| C & I Demand                        | \$0.03559    |
| C & I Demand Time of Day (On-Peak)  | \$0.04473    |
| C & I Demand Time of Day (Off-Peak) | \$0.02780    |
| Outdoor Lighting                    | \$0.02566    |

See Attachment A for the supporting calculations of these rates.

## MID-CONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) CHARGES

### Day 2 Market

Pursuant to the Commission's Orders in Case Nos. PU-05-147 and PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs in the FCR. The current FCR rates reflect MISO Day 2 charge types including three Auction Revenue Rights (ARR) and three Financial Transmission Rights (FTR) charge types.<sup>1</sup> Consistent with these Orders and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the September FCR the net MISO Day 2 costs for July as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is \$12,628,491 which is the net of many items.<sup>2</sup> Pursuant to the above-mentioned Orders, the Company also provides more detailed information in Attachment C of this filing to support the calculation of the MISO Day 2 costs.

### Ancillary Services Market (ASM)

With the implementation of the MISO ASM on January 6, 2009, the net costs or revenues of 14 ASM charge types are included in the FCR, pursuant to Commission guidance in Case No. PU-09-016. Consistent with the MISO Order and the required "net" accounting of ASM costs and revenues, we reflect in the September FCR rates the net MISO ASM costs for July as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is \$6,824,019, which is the net of many items. The detailed records are contained in Attachment C.

## INCLUDED REFUNDS

### Asset Based Margins

Under the terms of the Revised Second Amended Settlement adopted by the Commission on February 26, 2014 (retroactive to January 1, 2014), the Company began passing through to North Dakota customers 100 percent of wholesale asset-based margins.<sup>3</sup> July margins of \$904,747 have been included as an offsetting credit in this month's FCR. Additional information is found in Attachments B and F.

### Non-Asset Based Margins

Beginning in February 2011, the prior year retail share of Non-Asset Based Margins is credited to North Dakota customers via the FCR over the following 12-month period. The North Dakota retail share of the 2020 Non-Asset Based Margin credit amount applicable to the September FCR is \$142,710. See Attachments B and F.

### Sales of Renewable Energy Credits (RECs)

Pursuant to the Commission Order in Case No. PU-10-19, the Company was authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the North Dakota jurisdictional share of net proceeds generated by the sale back to customers through the FCR. Under the Commission's February 26, 2014 Order

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<sup>1</sup> Previously embedded in other FTR charge types.

<sup>2</sup> This excludes Schedule 24 charge and includes Schedule 49 charge.

<sup>3</sup> Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195

Adopting Settlement, the share of the net proceeds to customers was increased to 100 percent. The REC sales credit for the current reporting period is \$1,098,295. See Attachments B and F.

## **PURCHASED POWER AGREEMENT (PPA) COST RECOVERY REVIEW**

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement, the following procedural changes reflected in the Revised Second Amended Settlement were made to provide additional transparency regarding cost recovery of renewable energy projects or purchases:

- The Company will notify the Commission in its monthly FCR filings of any new renewable projects, qualifying in part or whole for FCR cost recovery, whose costs are included in the calculation of FCR rates;
- The Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year;
- If, within 6 months of the filing of the annual summary, the Commission does not initiate a review of the new PPA(s) listed, the Company will be allowed to recover the related costs for the duration of the contract(s); and
- Renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will not be included in the FCR unless and until the Commission has granted an Advance Determination of Prudence (ADP) for the resource.

It should be noted that MISO market energy purchases are not subject to the above requirements.

The following PPAs have been excluded from the FCR as a result of Commission review and disapproval:

1. School Sisters of Notre Dame (0.8 MW)<sup>4</sup>
2. Marshall Solar LLC (62.25 MW)<sup>5</sup>
3. North Star Solar PV (100 MW)<sup>6</sup>
4. Aurora Distributed Solar (100 MW)<sup>7</sup>

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<sup>4</sup> Case No. PU-16-458, ORDER REGARDING 2015 POWER PURCHASE AGREEMENT COSTS, October 5, 2016.

<sup>5</sup> The 62.25 MW Marshall Solar project is one of the three projects in the Company's proposed 187 MW solar energy portfolio that was not approved by the Commission (Case No. PU-14-810).

<sup>6</sup> The 100 MW North Star Solar project is one of the three projects in the Company's proposed 187 MW solar energy portfolio that was not approved by the Commission (Case No. PU-14-810).

<sup>7</sup> The Company's application for an advance determination of prudence for the proposed 100 MW Aurora Distributed Solar project was denied (Case No. PU-15-95).

## NEGOTIATED AGREEMENT PURCHASED POWER AGREEMENT EXCLUSIONS

Pursuant to the Commission's March 9, 2016 Order Accepting the Negotiated Agreement (Case Nos. PU-12-813, *et. al.*), the costs and volumes of 15 Community-Based Energy Development (C-BED) and two solar PPAs are to be excluded from the calculation of the Company's monthly FCR rates. Dragonfly Solar PPA was added to the exclusion list on September 2018.

The Company completed the closing process for the acquisition of the Jeffers and Community Wind North projects from Longroad Energy effective December 31, 2020. The PPAs with Jeffers Wind 20 LLC, North Community Turbines LLC, North Wind Turbines LLC have terminated effective December 31, 2020.

|  |  |
|--|--|
| 1. Jeffers Wind 20, LLC (50 MW) *        | 10. North Wind Turbines (15 MW) *          |
| 2. Big Blue (36 MW)                      | 11. Valley View Transmission (10 MW)       |
| 3. Community Wind South (Zephyr) (30 MW) | 12. Ulk Wind Farm (4.5 MW)                 |
| 4. Ridgewind Power Partners LLC (25 MW)  | 13. Hilltop Power (2 MW)                   |
| 5. Adams Wind Generations (20 MW)        | 14. Winona County Wind (1.5 MW)            |
| 6. Danielson Wind Farms (20 MW)          | 15. Woodstock Municipal Wind, LLC (0.8 MW) |
| 7. Ewington Energy Systems LLC (20 MW)   | 16. Outland Solar (2 MW)                   |
| 8. Grant County Wind, LLC (20 MW)        | 17. Best Power (St. Johns Solar) (0.4 MW)  |
| 9. North Community Turbines (15 MW) *    | 18. Dragonfly Solar, LLC (0.8 MW)          |

\* PPA terminated

See Attachment D for more details concerning the calculation of the replacement energy costs (i.e., the system average) used to effectuate the impact of disallowing these PPAs.

## COMMUNITY SOLAR GARDENS COST TREATMENT

In our response to NDPSC Staff Data Request No. 1 submitted in Case No. PU-17-12 on August 23, 2017, the Company committed to including additional information in our FCR filings regarding the costs related to the Minnesota Community Solar Gardens program production and cost allocation to North Dakota. This information is in Attachment H.

## BIOMASS PPA TERMINATION COST RECOVERY

Pursuant to Commission's June 27, 2018 Order in Case Nos. PU-17-270 (ADP – Benson, Pine Bend and HERC PPAs), PU-17-271 and PU-17-322 (Deferred Accounting of Benson, Pine Bend and Laurentian PPAs termination cost recovery) the September FCR includes \$54,505 in termination cost recovery. Pine Bend PPA termination cost recovery was completed in May 2020 FCR. The itemized cost recovery information is found in Attachment F.

## MONTHLY FCR RATE CALCULATION AND SUPPORTING DOCUMENTS

This filing includes the following supporting documents:

- Attachment A – Summary of Calculation of the Monthly 2021 FCR Rate
- Attachment B – Four Month Fuel Cost Rider Costs
- Attachment C – Detail of MISO Day 2 and ASM Settlement Charges
- Attachment D – Derivation of Replacement Costs for Disallowed PPAs
- Attachment E – Deviation of FCR True-Up Adjustment
- Attachment F – Summary of Credits and Special Charges Included in the FCR
- Attachment G – Historical Trend of FCR Charges (Residential)
- Attachment H – Community Solar Garden Costs Allocated To North Dakota FCA

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist at 701-241-8632 or [dave.sederquist@xcelenergy.com](mailto:dave.sederquist@xcelenergy.com).

Sincerely,

/ s /

LISA PETERSON  
MANAGER, REGULATORY ANALYSIS

cc: David H. Sederquist

Enclosures

Summary of Fuel Cost Rider Rates - September 2021

|   |  |  |
|---|--|--|
| <b>System Fuel and Purchased Energy Costs</b>         |  | <u>4 Month Total</u>                       |
| 1 NSP System Fuel/Energy Costs (Retail)               |  | \$314,153,153 Att B, p. 1, line 6          |
| 2 MISO Charges  |  | \$96,891,449 Att B, p. 1, line 10          |
| 3 Disallowed Purchased Power Costs                    |  | <u>(\$16,007,242) Att B, p. 1, line 14</u> |
| 4 Net NSP System Costs                                |  | <u>\$395,037,360</u>                       |
| <b>ND Fuel and Purchased Energy Costs</b>             |  | <u>4 Month Total</u>                       |
| 5 NSP System MWh Sales (Retail)                       |  | 12,961,126 Att B, p. 1, line 16            |
| 6 Average NSP System Cost per kWh                     |  | 3.048¢ line 4 / line 5/10                  |
| 7 ND MWh Sales (Retail)                               |  | <u>676,341 Att B, p. 1, line 18</u>        |
| 8 ND Fuel & Purchased Energy Costs                    |  | <u>\$20,614,874 line 6 x line 7</u>        |
| <b>Credits and Other Adjustments Applicable to ND</b> |  | <u>July 2021</u>                           |
| 9 Wholesale Margins Credit                            |  | (\$1,047,458) Att B, p. 1, line 20,21      |
| 10 REC Sales Proceeds Credit                          |  | (\$1,098,295) Att B, p. 1, line 22         |
| 11 Biomass PPA Termination Costs                      |  | \$54,505 Att B, p. 1, line 23              |
| 12 Net Credits and Other                              |  | <u>(\$2,091,247)</u>                       |
| <b>Over/Under Recovered Costs</b>                     |  | <u>Amount</u>                              |
| 13 True-Up Amount for July 2021                       |  | \$5,115,471 Att E, p.1, line 19            |
| <b>ND Net FCR Costs</b>                               |  | <u>4 Month Total</u>                       |
| 14 Net FCR Costs                                      |  | \$23,639,097 line 8+line 12+line 13        |
| 15 Net FCR Cost per kWh                               |  | 3.495¢ line 14 / line 7/10                 |

**Fuel Cost Rider Rate By Class**

| Customer Class               | ND Cost of Fuel/kWh | Cust. Class Ratio <sup>1</sup> | FCR Rate      |
|------------------------------|---------------------|--------------------------------|---------------|
| 16 Residential               | 3.495¢              | 0.99690                        | <b>3.484¢</b> |
| 17 C & I Non-Demand          | 3.495¢              | 1.03180                        | <b>3.606¢</b> |
| 18 C & I Demand Non-TOD      | 3.495¢              | 1.01840                        | <b>3.559¢</b> |
| 19 C & I Demand TOD On-Peak  | 3.495¢              | 1.27980                        | <b>4.473¢</b> |
| 20 C & I Demand TOD Off-Peak | 3.495¢              | 0.79540                        | <b>2.780¢</b> |
| 21 Outdoor Lighting          | 3.495¢              | 0.73410                        | <b>2.566¢</b> |

<sup>1</sup> See Fuel Cost Rider Tariff.

4 Month Fuel Cost Rider Costs - September 2021

|   | (A)            | (B)            | (C)            | (D)            | (E)             |
|---|----------------|----------------|----------------|----------------|-----------------|
| <b>Fuel &amp; Purchased Energy Costs</b>      | Apr-21         | May-21         | Jun-21         | Jul-21         | 4 Month Total   |
| 1 Account 151 - Fossil Fuel                   | \$19,802,110   | \$22,147,716   | \$42,181,217   | \$52,673,518   | \$136,804,561   |
| 2 Account 518 - Nuclear Fuel                  | \$7,919,800    | \$7,788,019    | \$9,772,366    | \$10,083,832   | \$35,564,017    |
| 3 Account 555 - Purchased Power <sup>1</sup>  | \$54,733,196   | \$61,239,760   | \$74,334,873   | \$65,876,676   | \$256,184,505   |
| 4 Sub-Total NSP Sys Energy Costs              | \$82,455,106   | \$91,175,495   | \$126,288,456  | \$128,634,026  | \$428,553,083   |
| 5 Exclude Costs of InterSystem Sales          | (\$22,000,245) | (\$24,388,821) | (\$31,388,999) | (\$36,621,865) | (\$114,399,930) |
| 6 Total Sys Fuel & Purch Energy               | \$60,454,861   | \$66,786,674   | \$94,899,457   | \$92,012,161   | \$314,153,153   |
| <b>MISO Charges</b>                           |                |                |                |                |                 |
| 7 Day 2 Market                                | \$21,254,217   | \$19,381,609   | \$31,427,447   | \$12,738,162   | \$84,801,436    |
| 8 Exclude Schedule 24                         | (\$79,274)     | (\$74,480)     | (\$118,880)    | (\$109,672)    | (\$382,306)     |
| 9 Ancillary Services Market                   | \$1,338,267    | \$359,583      | \$3,950,451    | \$6,824,019    | \$12,472,320    |
| 10 Total MISO Charges                         | \$22,513,210   | \$19,666,712   | \$35,259,018   | \$19,452,509   | \$96,891,449    |
| <b>Disallowed PPA Costs<sup>2</sup></b>       |                |                |                |                |                 |
| 11 Exclude Costs of Disallowed PPAs           | (\$5,665,579)  | (\$6,413,935)  | (\$6,793,829)  | (\$5,700,477)  | (\$24,573,820)  |
| 12 Exclude Related Curtailment Costs          | (\$476,222)    | (\$381,843)    | (\$243,835)    | (\$155,415)    | (\$1,257,315)   |
| 13 Replacement Energy Costs                   | \$2,161,514    | \$2,415,244    | \$3,279,828    | \$1,967,306    | \$9,823,892     |
| 14 Net Disallowance                           | (\$3,980,287)  | (\$4,380,534)  | (\$3,757,835)  | (\$3,888,586)  | (\$16,007,242)  |
| 15 Net NSP System Costs                       | \$78,987,784   | \$82,072,853   | \$126,400,640  | \$107,576,084  | \$395,037,360   |
| <b>ND Fuel and Purchased Energy Costs</b>     |                |                |                |                |                 |
| 16 NSP System Sales (Retail)                  | 2,906,491      | 2,687,120      | 3,537,121      | 3,830,394      | 12,961,126      |
| 17 Avg. NSP System Cost per kWh               | 2.718¢         | 3.054¢         | 3.574¢         | 2.808¢         | 3.048¢          |
| 18 ND Sales (Retail)                          | 164,160        | 141,904        | 177,571        | 192,706        | 676,341         |
| 19 ND Fuel & Purchased Energy Costs           | \$4,461,869    | \$4,333,748    | \$6,346,388    | \$5,411,184    | \$20,614,874    |
| <b>Other Adjustments and True-Up</b>          |                |                |                |                |                 |
| 20 Asset-Based Margins                        | (\$2,628,486)  | (\$672,711)    | (\$2,512,747)  | (\$904,747)    | (\$6,718,691)   |
| 21 Non-Asset-Based Margins                    | (\$18,186)     | (\$202,692)    | (\$16,452)     | (\$142,710)    | (\$380,040)     |
| 22 REC Sales Proceeds (100%)                  | (\$2,404)      | (\$1,540,277)  | (\$483,961)    | (\$1,098,295)  | (\$3,124,937)   |
| 23 Biomass PPA Termination Costs <sup>3</sup> | \$54,962       | \$55,336       | \$962,479      | \$54,505       | \$1,127,283     |
| 24 Net Credits and Other                      | (\$2,594,114)  | (\$2,360,344)  | (\$2,050,681)  | (\$2,091,247)  | (\$9,096,386)   |

<sup>1</sup> Excludes demand-related expenses, MN Windsource energy costs, and MN Solar Gardens energy costs.

<sup>2</sup> Excludes costs exceeding system average costs for 21 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement (PU-12-813) & other ADP docket.

<sup>3</sup> Benson, Laurentian and Pine Bend PPAs.

MISO Day 2 Settlement Charges - September 2021

|   | FERC Account | Retail<br>Expense (Rev)     |
|---|--------------|-----------------------------|
| <b>Energy and Losses</b>  |              |                             |
| 1 Day Ahead Asset Energy - Energy                                 | 555          | \$9,344,229                 |
| 2 Day Ahead Asset Energy - Losses                                 | 555          | \$5,382,354                 |
| 3 Day Ahead Financial Bilateral Transaction Loss                  | 555          | \$3,626                     |
| 4 Day Ahead Non-Asset Energy - Energy                             | 555          | (\$10,455,186)              |
| 5 Day Ahead Non-Asset Energy - Losses                             | 555          | \$523,568                   |
| 6 Day Ahead Losses Rebate on Carve-out Grandfathered Agreements   | 555          | (\$3,661)                   |
| 7 Day Ahead Losses Rebate on Option B Grandfathered Agreements    | 555          | \$0                         |
| 8 Real Time Asset Energy - Energy                                 | 555          | (\$1,327,028)               |
| 9 Real Time Asset Energy - Losses                                 | 555          | \$68,185                    |
| 10 Real Time Distribution of Losses                               | 555          | (\$2,035,692)               |
| 11 Real Time Financial Bilateral Transaction - Losses             | 555          | \$0                         |
| 12 Real Time Losses Rebate on Carve-out Grandfathered Agreements  | 555          | \$0                         |
| 13 Real Time Net Inadvertent Distribution                         | 555          | (\$89,111)                  |
| 14 Real Time Non-Asset Energy - Energy                            | 555          | \$117,473                   |
| 15 Real Time Non-Asset Energy - Losses                            | 555          | \$0                         |
| 16 <b>Total Energy and Losses</b>                                 |              | <u><u>\$1,528,759</u></u>   |
| <b>Congestion</b>   |              |                             |
| 17 Day Ahead Asset Energy - Congestion                            | 555          | \$14,026,509                |
| 18 Day Ahead Financial Bilateral Transaction - Congestion         | 555          | \$12,385                    |
| 19 Day Ahead Non-Asset Energy - Congestion                        | 555          | \$31,443                    |
| 20 Day Ahead Congestion Rebate - Carve-out Grandfather Agreements | 555          | (\$12,234)                  |
| 21 Day Ahead Congestion Rebate - Option B Grandfather Agreements  | 555          | \$0                         |
| 22 Real Time Asset Energy - Congestion                            | 555          | (\$56,985)                  |
| 23 Real Time Financial Bilateral Transaction - Congestion         | 555          | \$0                         |
| 24 Real Time Congestion Rebate - Carve-out Grandfather Agreements | 555          | \$0                         |
| 25 Real Time Non-Asset Energy - Congestion                        | 555          | \$0                         |
| 26 <b>Total Congestion-Related</b>                                |              | <u><u>\$14,001,119</u></u>  |
| <b>Financial Transmission Rights (FTR)</b>                        |              |                             |
| 27 FTR Hourly Allocation  | 555          | (\$3,783,140)               |
| 28 FTR Monthly Allocation   | 555          | (\$26,444)                  |
| 29 FTR Transaction  | 555          | \$0                         |
| 30 FTR Yearly Allocation  | 555          | \$0                         |
| 31 FTR Full Funding Guarantee                                     | 555          | \$96,333                    |
| 32 FTR Guarantee Uplift   | 555          | (\$95,905)                  |
| 33 FTR Monthly Transaction  | 555          | \$0                         |
| 34 <b>Total Financial Transmission Rights Charges</b>             |              | <u><u>(\$3,809,157)</u></u> |

MISO Day 2 Settlement Charges - September 2021

|  | <u>FERC Account</u> | <b>Retail<br/><u>Expense (Rev)</u></b> |
|--|---------------------|--|
| <b>Uplift</b>                                    |                     |  |
| 35 Real-Time Revenue Neutrality Uplift           | 555                 | \$404,741                              |
| 36 <b>Total Uplift</b>                           |                     | <u>\$404,741</u>                       |
| <b>Revenue Sufficiency Guarantee (RSG)</b>       |                     |  |
| 37 Day Ahead RSG Distribution                    | 555                 | \$114,721                              |
| 38 Day Ahead RSG Make Whole Payment              | 555                 | (\$15,061)                             |
| 39 Real time RSG First Pass Distribution         | 555                 | \$914,878                              |
| 40 Real Time RSG Make Whole Payment              | 555                 | (\$618,211)                            |
| 41 Real Time Price Volatility Make Whole Payment | 555                 | (\$90,746)                             |
| 42 <b>Total Revenue Sufficiency Guarantee</b>    | 555                 | <u>\$305,581</u>                       |
| <b>Market Administration<sup>1</sup></b>         |                     |  |
| 43 Day Ahead Market Administration               | 575.7               | \$556,461                              |
| 44 Real Time Market Administration               | 575.7               | \$50,269                               |
| 45 FTR Market Administration                     | 575.7               | \$24,301                               |
| 46 <b>Total Market Administration</b>            |                     | <u>\$631,031</u>                       |
| <b>Virtual Energy</b>                            |                     |  |
| 47 Day Ahead Virtual Energy                      | 555                 | \$0                                    |
| 48 Real Time Virtual Energy                      | 555                 | \$0                                    |
| 49 <b>Total Virtual Energy</b>                   | 555                 | <u>\$0</u>                             |
| <b>Auction Revenue Rights (ARR)</b>              |                     |  |
| 50 ARR FTR Auction Transactions                  | 555                 | \$2,869,718                            |
| 51 ARR Monthly Revenue                           | 555                 | (\$2,871,894)                          |
| 52 ARR Stage 2 Distribution                      | 555                 | (\$721,100)                            |
| 53 ARR Monthly Infeasible Revenue                | 555                 | \$176,936                              |
| 54 <b>Total Auction Revenue Rights</b>           |                     | <u>(\$546,340)</u>                     |
| <b>Other Miscellaneous</b>                       |                     |  |
| 55 Real Time Miscellaneous                       | 555                 | \$112,756                              |
| 56 Real Time Uninstructed Deviation              | 555                 | \$0                                    |
| 57 <b>Total Other Miscellaneous</b>              |                     | <u>\$112,756</u>                       |
| 58 <b>Grand Total MISO Day 2 Charges</b>         |                     | <u><u>\$12,628,491</u></u>             |

<sup>1</sup> Excludes Schedule 24 costs, which are recovered in base rates.

MISO Ancillary Services Markets (ASM) Charges - September 2021

|   | FERC Account | Retail<br>Expense (Rev)   |
|---|--------------|---------------------------|
| <b>Procurement</b>                                  |              |                           |
| 1 Day Ahead Regulation                              | 555          | (\$239,360)               |
| 2 Day Ahead Spinning Reserve                        | 555          | (\$252,603)               |
| 3 Day Ahead Supplemental Reserve                    | 555          | (\$34,149)                |
| 4 Real Time Regulation                              | 555          | \$61,582                  |
| 5 Real Time Spinning Reserve                        | 555          | \$135,667                 |
| 6 Real Time Supplemental Reserve                    | 555          | \$10,392                  |
| 7 <b>Total Procurement</b>                          |              | <u>(\$318,471)</u>        |
| <b>Resource Energy</b>                              |              |                           |
| 8 Real Time Excessive Energy                        | 555          | (\$9,544)                 |
| 9 Real Time Excessive Energy - Congestion           | 555          | \$0                       |
| 10 Real Time Excessive Energy - Losses              | 555          | \$0                       |
| 11 Real Time Non-Excessive Energy                   | 555          | \$6,740,447               |
| 12 Real Time Non-Excessive Energy - Congestion      | 555          | (\$45,171)                |
| 13 Real Time Non-Excessive Energy - Losses          | 555          | (\$50,570)                |
| 14 Real Time Net Regulation Adjustment              | 555          | \$2,329                   |
| 15 <b>Total Resource Energy</b>                     |              | <u>\$6,637,491</u>        |
| <b>Cost Distribution</b>                            |              |                           |
| 16 Real Time Regulation Reserve Cost Distribution   | 555          | \$193,383                 |
| 17 Real Time Spinning Reserve Cost Distribution     | 555          | \$228,895                 |
| 18 Real Time Supplemental Reserve Cost Distribution | 555          | \$47,342                  |
| 19 <b>Total Cost Distribution</b>                   |              | <u>\$469,620</u>          |
| <b>Penalties</b>                                    |              |                           |
| 20 Real Time Excessive/Deficient Energy Deployment  | 555          | \$35,379                  |
| 21 Real Time Contingency Reserve Deployment Failure | 555          | \$0                       |
| 22 <b>Total Penalties</b>                           |              | <u>\$35,379</u>           |
| 23 <b>Grand Total ASM Charges</b>                   |              | <u><u>\$6,824,019</u></u> |

**Derivation of July 2021 Replacement Costs for Disallowed PPAs**

| <b>Fuel &amp; Purchased Energy Costs</b> |   | <u>NSP System</u> | <u>ND Allocation<sup>1</sup></u> | <u>ND Jurisdiction</u> |                         |
|--|---|-------------------|----------------------------------|------------------------|-------------------------|
| 1  | Fuel & Purch Energy Costs (Retail) <sup>2</sup>   | \$111,464,670     | 5.0310%                          | \$5,607,755            | Att B, Col D, line 6+10 |
| Disallowed PPA Costs                     |   |                   |                                  |                        |                         |
| 2  | 15 C-BED Wind PPAs                                | (\$911,012)       | 5.0310%                          | (\$45,833)             |                         |
| 3  | 7 Solar PPAs                                      | (\$4,789,465)     | 5.0310%                          | (\$240,957)            |                         |
| 4  | Wind Curtailment Payments                         | (\$155,415)       | 5.0310%                          | (\$7,819)              |                         |
| 5  | Total Exclusion                                   | (\$5,855,892)     |                                  | (\$294,608)            |                         |
| 6  | Adjusted Fuel & Purchased Energy Costs            | \$105,608,778     | 5.0310%                          | \$5,313,147            | Line 1 - line 5         |
| <b>Energy Sales (Billing Mo.)</b>        |   |                   |                                  |                        |                         |
|  |   | [a]               | [b]                              | [c]                    |                         |
| 7  | MWh Energy Sales                                  | 3,830,394         | 5.0310%                          | 192,706                | [b]=[c]/[a]             |
| 8  | Disallowed PPA MWh Energy Sales                   | (70,061)          | 5.0310%                          | (3,525)                |                         |
| 9  | Adjusted MWh Sales (Billing Mo.)                  | 3,760,333         |                                  | 189,181                |                         |
| <b>Replacement Costs</b>                 |   |                   |                                  |                        |                         |
| 10                                       | Avg. Cost (\$/MWh) w/o Disallowed PPAs            | \$28.08           |                                  | \$28.08                | Line 6 / line 9         |
| 11                                       | Replacement Cost for Disallowed PPAs <sup>3</sup> | \$1,967,313       |                                  | \$98,982               | Line 8 x line 10        |
| <b>Impact of Disallowance</b>            |   |                   |                                  |                        |                         |
| 12                                       | Net Impact of Disallowance                        | (\$3,888,579)     |                                  | (\$195,626)            | Line 5 + line 11        |
| 13                                       | FCR Rate Impact of Disallowance /kWh              |                   |                                  | -0.102¢                | Line 12 / line 7        |
| 14                                       | Residential Monthly Bill Impact (750 kWh)         |                   |                                  | (\$0.76)               | Line 13 x 750           |

<sup>1</sup> Based on ratio of ND billed energy sales to NSP System billed sales as shown in line 7

<sup>2</sup> Including MISO charges

<sup>3</sup> Reflects the average system fuel and purchased energy cost per kWh (excluding the disallowed PPA costs and volumes) applied to the energy volumes of the disallowed PPAs.

Derivation of FCR True-Up Adjustment - July 2021

**Cost to Recover in July 2021**

|                                 | [a]<br>Jul Sys Fuel<br>Cost/kWh <sup>1</sup> | [b]<br>Jul ND<br>MWh Sales <sup>2</sup> | Amount              |                 |
|---------------------------------|--|---|---------------------|-----------------|
| 1 Fuel & Purchased Energy Costs | 2.808¢                                       | 192,706                                 | \$5,411,184         |                 |
| 2 True Up Amount for May 2021   |  |   | \$4,922,334         |                 |
| 3 Net Costs                     |  |   | <u>\$10,333,519</u> | Line 1 + Line 2 |

**Cost Recovered in July 2021**

|                                 | Sales          | Amount             |
|---------------------------------|----------------|--------------------|
| 4 (i) Residential               | 67,181         | \$1,676,885        |
| 5 (ii) C & I Non-Demand         | 7,829          | \$200,990          |
| 6 (iii) C & I Demand Non-TOD    | 64,741         | \$1,639,408        |
| 7 (iv) C & I Demand TOD On-Peak | 19,787         | \$632,250          |
| 8 (v) C & I Demand TOD Off-Peak | 32,215         | \$640,005          |
| 9 (vi) Outdoor Lighting         | 953            | \$17,199           |
| 10 Total                        | <u>192,706</u> | <u>\$4,806,737</u> |

**True-Up Obligation**

|                                  |                |                  |
|----------------------------------|----------------|------------------|
| 11 (i) Residential               | 67,181         | \$150,749        |
| 12 (ii) C & I Non-Demand         | 7,829          | \$15,232         |
| 13 (iii) C & I Demand Non-TOD    | 64,741         | \$128,933        |
| 14 (iv) C & I Demand TOD On-Peak | 19,787         | \$56,910         |
| 15 (v) C & I Demand TOD Off-Peak | 32,215         | \$59,204         |
| 16 (vi) Outdoor Lighting         | 953            | \$283            |
| 17 Total                         | <u>192,706</u> | <u>\$411,311</u> |

|                 |                    |                   |
|-----------------|--------------------|-------------------|
| 18 Net Recovery | <u>\$5,218,048</u> | Line 10 + Line 17 |
|-----------------|--------------------|-------------------|

**Over/Under Recovered Costs**

|                                 |                    |                  |
|---------------------------------|--------------------|------------------|
| 19 True-Up Amount for July 2021 | <u>\$5,115,471</u> | Line 3 - Line 18 |
|---------------------------------|--------------------|------------------|

<sup>1</sup> Reflects the average for the month of July 2021.

<sup>2</sup> Actual ND sales in month of July 2021.

Summary of Credits and Other Adjustments Included in the FCR by Month

Margin Sharing and REC Sales Proceeds Credits

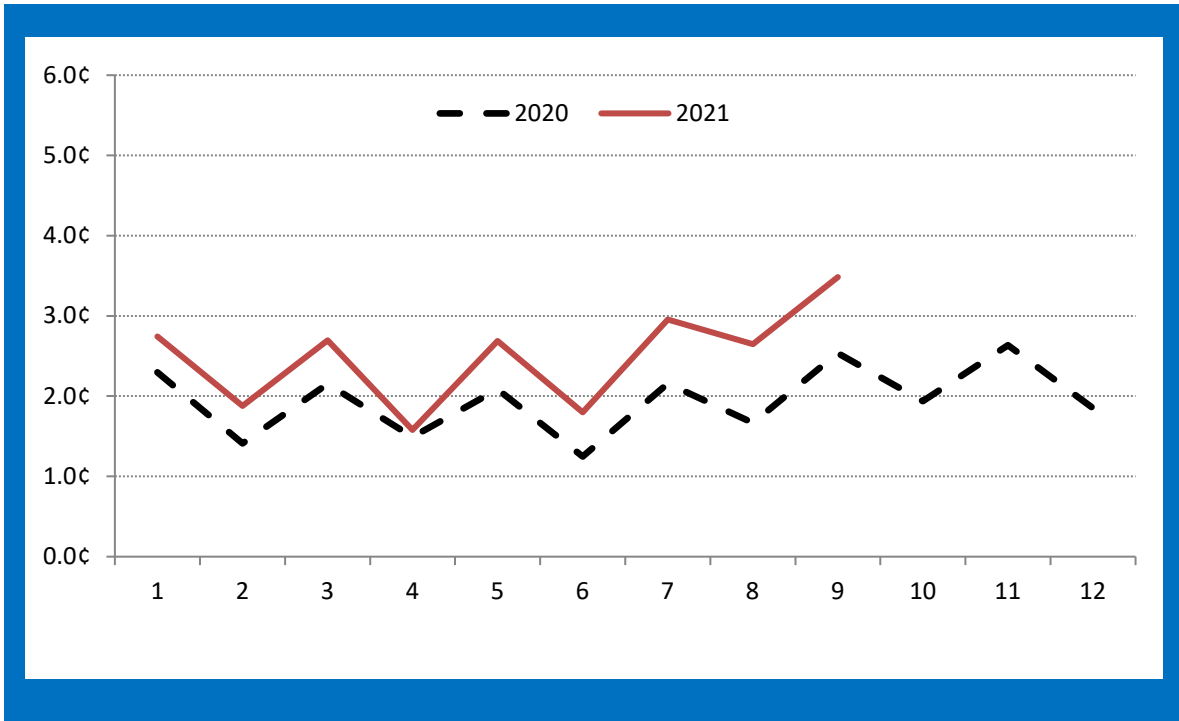
| Month         | Asset Based Margins   | Non-Asset Based Margins |  | Renewable Energy Credits | Total                 |
|---------------|-----------------------|-------------------------|--|--------------------------|-----------------------|
| 1 January     | (\$909,675)           | (\$353,975)             |  | (\$117,989)              | (\$1,381,639)         |
| 2 February    | (\$3,171,095)         | (\$14,652)              |  | (\$39)                   | (\$3,185,786)         |
| 3 March       | (\$518,508)           | (\$258,147)             |  | (\$83,954)               | (\$860,609)           |
| 4 April       | (\$2,628,486)         | (\$18,186)              |  | (\$2,404)                | (\$2,649,076)         |
| 5 May         | (\$672,711)           | (\$202,692)             |  | (\$1,540,277)            | (\$2,415,680)         |
| 6 June        | (\$2,512,747)         | (\$16,452)              |  | (\$483,961)              | (\$3,013,160)         |
| 7 July        | (\$904,747)           | (\$142,710)             |  | (\$1,098,295)            | (\$2,145,753)         |
| 8 August      |                       |                         |  |                          |                       |
| 9 September   |                       |                         |  |                          |                       |
| 10 October    |                       |                         |  |                          |                       |
| 11 November   |                       |                         |  |                          |                       |
| 12 December   |                       |                         |  |                          |                       |
| 13 Cumulative | <b>(\$11,317,969)</b> | <b>(\$1,006,814)</b>    |  | <b>(\$3,326,919)</b>     | <b>(\$15,651,703)</b> |

Biomass Contracts Termination Cost Recovery

| Month         | Benson Amortization (Regulatory Asset) | Benson Amortization (Plant Impairment) | Benson ROE (Regulatory Asset) | Benson ROE (Plant Impairment) | Laurentian Payment | Pine Bend Payment | Total              |
|---------------|--|--|-------------------------------|-------------------------------|--------------------|-------------------|--------------------|
|               | FERC 557                               | FERC 407                               | FERC 182.2                    | FERC 182.3                    |                    |                   |                    |
| 14 January    | \$19,946                               | \$22,387                               | \$6,117                       | \$6,790                       | \$0                | \$0               | \$55,239           |
| 15 February   | \$19,946                               | \$22,387                               | \$6,047                       | \$6,712                       | \$0                | \$0               | \$55,091           |
| 16 March      | \$19,946                               | \$22,387                               | \$5,977                       | \$6,635                       | \$0                | \$0               | \$54,944           |
| 17 April      | \$19,946                               | \$22,387                               | \$5,907                       | \$6,723                       | \$0                | \$0               | \$54,962           |
| 18 May        | \$19,946                               | \$22,387                               | \$6,364                       | \$6,640                       | \$0                | \$0               | \$55,336           |
| 19 June       | \$19,946                               | \$22,387                               | \$5,768                       | \$6,557                       | \$907,822          | \$0               | \$962,479          |
| 20 July       | \$19,946                               | \$22,387                               | \$5,698                       | \$6,475                       | \$0                | \$0               | \$54,505           |
| 21 August     |  |  |                               |                               |                    |                   |                    |
| 22 September  |  |  |                               |                               |                    |                   |                    |
| 23 October    |  |  |                               |                               |                    |                   |                    |
| 24 November   |  |  |                               |                               |                    |                   |                    |
| 25 December   |  |  |                               |                               |                    |                   |                    |
| 26 Cumulative | <b>\$139,620</b>                       | <b>\$156,706</b>                       | <b>\$41,878</b>               | <b>\$46,532</b>               | <b>\$907,822</b>   | <b>\$0</b>        | <b>\$1,292,558</b> |

May 2021 Benson ROE included \$527 true-up return for change in deferred taxes.

### Historical Trend of FCR Charges (Residential)



| <b>Residential Fuel Cost Charges</b> |           | <u>2020</u> | <u>Bill Impact<sup>1</sup></u> | <u>2021</u> | <u>Bill Impact<sup>1</sup></u> |
|--------------------------------------|-----------|-------------|--------------------------------|-------------|--------------------------------|
| 1                                    | January   | 2.298¢      | \$17.24                        | 2.742¢      | \$20.57                        |
| 2                                    | February  | 1.413¢      | \$10.60                        | 1.878¢      | \$14.09                        |
| 3                                    | March     | 2.152¢      | \$16.14                        | 2.694¢      | \$20.21                        |
| 4                                    | April     | 1.492¢      | \$11.19                        | 1.579¢      | \$11.84                        |
| 5                                    | May       | 2.087¢      | \$15.65                        | 2.688¢      | \$20.16                        |
| 6                                    | June      | 1.248¢      | \$9.36                         | 1.797¢      | \$13.48                        |
| 7                                    | July      | 2.157¢      | \$16.18                        | 2.955¢      | \$22.16                        |
| 8                                    | August    | 1.667¢      | \$12.50                        | 2.648¢      | \$19.86                        |
| 9                                    | September | 2.538¢      | \$19.04                        | 3.484¢      | \$26.13                        |
| 10                                   | October   | 1.937¢      | \$14.53                        |             |                                |
| 11                                   | November  | 2.635¢      | \$19.76                        |             |                                |
| 12                                   | December  | 1.850¢      | \$13.88                        |             |                                |
| 13                                   | Average   | 1.956¢      | \$14.67                        | 2.496¢      | \$18.72                        |

<sup>1</sup> For non-electric heating residential customers using 750 kWh

Community Solar Garden Costs Allocated To North Dakota FCA

|  | August 2020  | September 2020 | October 2020 | November 2020 | December 2020 | January 2021 | February 2021 | March 2021   | April 2021   | May 2021     | June 2021    | July 2021    | 12-Month Total |
|--|--------------|----------------|--------------|---------------|---------------|--------------|---------------|--------------|--------------|--------------|--------------|--------------|----------------|
| 1 Market Priced Cost                     | \$3,003,396  | \$1,537,897    | \$1,408,268  | \$1,091,205   | \$921,891     | \$3,708,007  | \$3,207,718   | \$11,196,333 | \$6,273,617  | \$4,439,663  | \$15,240,436 | \$7,139,115  | \$59,167,547   |
| 2 Above Market Cost                      | \$14,359,648 | \$11,068,799   | \$10,514,941 | \$11,854,697  | \$6,084,742   | \$5,939,783  | \$5,633,105   | \$7,636,721  | \$6,049,883  | \$15,273,454 | \$13,699,998 | \$12,971,464 | \$121,087,234  |
| 3 Total Solar Gardens (1)+(2)            | \$17,363,044 | \$12,606,696   | \$11,923,209 | \$12,945,903  | \$7,006,633   | \$9,647,790  | \$8,840,823   | \$18,833,054 | \$12,323,500 | \$19,713,117 | \$28,940,434 | \$20,110,579 | \$180,254,781  |
| 4 ND Billing Month Sales                 | 181,752      | 172,424        | 159,361      | 150,770       | 188,192       | 192,900      | 186,477       | 210,752      | 164,160      | 141,904      | 177,571      | 192,706      | 2,118,969      |
| 5 Billing Month System Sales             | 3,651,149    | 3,371,857      | 2,995,712    | 2,740,381     | 3,269,049     | 3,340,837    | 3,015,626     | 3,441,751    | 2,906,491    | 2,687,120    | 3,537,121    | 3,830,394    | 38,787,488     |
| 6 ND Allocator (4)/(5)                   | 4.97794%     | 5.11362%       | 5.31964%     | 5.50179%      | 5.75678%      | 5.77400%     | 6.18369%      | 6.12339%     | 5.64805%     | 5.28090%     | 5.02021%     | 5.03097%     | 5.46302%       |
| 7 Market Costs (1)                       | \$3,003,396  | \$1,537,897    | \$1,408,268  | \$1,091,205   | \$921,891     | \$3,708,007  | \$3,207,718   | \$11,196,333 | \$6,273,617  | \$4,439,663  | \$15,240,436 | \$7,139,115  | \$59,167,547   |
| 8 ND Solar Gardens Allocation<br>(7)×(6) | \$149,507    | \$78,642       | \$74,915     | \$60,036      | \$53,071      | \$214,100    | \$198,355     | \$685,596    | \$354,337    | \$234,454    | \$765,102    | \$359,167    | \$3,227,283    |