



414 Nicollet Mall  
Minneapolis, MN 55401

August 27, 2025

—Via Electronic Filing—

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

RE: SEPTEMBER 2025 FUEL COST RIDER RATES  
CASE NO. PU-25-011

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 2025.

The table below shows the FCR rates by customer class:

September 2025	FCR rate/kWh
Residential	\$0.03130
C & I Non-Demand	\$0.03141
C & I Demand	\$0.03122
C & I Demand Time of Day (On-Peak)	\$0.03777
C & I Demand Time of Day (Off-Peak)	\$0.02602
Outdoor Lighting	\$0.02423

See Attachment A for the supporting calculations of these rates.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2020 rate proceeding (Case No. PU-20-441), new base rates were implemented on October 1, 2021. The new Service Category Ratios listed below

became effective when actual October 2021 fuel and purchased energy costs were first passed through in December 2021 FCR rates:

Service Category Ratios	Effective October 1, 2021
Residential	1.0094
C & I Non-Demand	1.0129
C & I Demand	1.0069
C & I Demand Time of Day (On-Peak)	1.2181
C & I Demand Time of Day (Off-Peak)	0.8392
Outdoor Lighting	0.7813

## 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 2025 FCR the net MISO Day 2 costs for July 2025 as recorded in Account 555. The MISO Day 2 cost recovery included in this month’s FCR is \$20,866,165 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 2025 FCR rates the net MISO ASM costs for July 2025 as recorded in Account 555. The MISO ASM cost recovery included in this month’s FCR is \$17,070,788 which is the net of many items. The detailed records are contained in Attachment C.

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

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

## CUSTOMER REFUNDS AND CREDITS

### 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> Pursuant to the Commission's August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), credits derived from any disallowed resources (Company-owned or power purchase agreements) after January 1, 2021 are excluded from this sharing. Because of the nature of the calculation, the adjustment to remove the margins will only be done once the MISO S105 settlements are complete. Margins of \$2,251,361 have been included as an offsetting credit in this month's FCR. See Attachments B and F.

### Non-Asset Based Margins

Beginning in February 2011, 50% of the prior year retail share of Non-Asset Based Margins is credited to North Dakota customers via the FCR. The North Dakota retail share of the 2024 Non-Asset Based Margin credit amount is \$0. With the prior month true up the total applicable amount to the September 2025 FCR is \$3,666. 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 Adopting Settlement, the share of the net proceeds to customers was increased to 100 percent. Pursuant to the Commission's August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), credits derived from any disallowed resources or power purchase agreements after January 1, 2021 are excluded from this sharing. This change will be implemented in a future monthly FCR filing when the sale of disputed resource RECs takes place. With the prior month true up, the REC sales credit for the current reporting period is \$517,122. See Attachments B and F.

---

<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

## **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.

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>

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

## **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-

---

<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).

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<sup>8</sup> PPA was added to the exclusion list in September 2018 (see table below). 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 and North Wind Turbines LLC were 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. Uilk 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. Restore Renewables (Dragonfly Solar) (0.8 MW)

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 resources.

### **NSP-OWNED WIND RESOURCE PRICING ADJUSTMENT**

Pursuant to the Commission’s August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), the Company owned Community Wind North, Jeffers Wind and Rock Aetna wind facilities are repriced at average system cost and recovered in the monthly FCR charge. The effect of the repricing is included in Attachment D.

### **MISO REVENUE EXCLUSION FOR DISPUTED RESOURCES**

Pursuant to the Commission’s August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), the MISO wholesale revenues of disputed resources are excluded from the calculation of the Company’s monthly FCR after January 1, 2021. The July 2025 system amount is \$8,880,416 as shown on line 12 of Attachment B.

---

<sup>8</sup> Restore Renewables bought the solar facility from Dragonfly Solar LLC.

In September 2024, Sherco Solar Unit 1 began to provide energy as part of testing procedures. Under the normal process for disputed resources in ND, we repriced the energy at the average system cost, and excluded the MISO revenues from the fuel clause calculations.

## **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 (CSG) program production and cost assignment to North Dakota. As shown on Attachment H, North Dakota customers do not pay the actual costs of CSG production but are instead allocated a portion of the “market” costs for the same energy produced by the CSG program. As a result, North Dakota customers are insulated from all CSG costs.

## **BIOMASS PPA TERMINATION COST RECOVERY**

Pursuant to the Commission’s June 27, 2018 Orders in Case No. PU-17-270 (ADP – Benson, Pine Bend, and Hennepin Energy Recovery Center (HERC) PPA terminations), Case No. PU-17-271 (Deferred Accounting for Benson, Pine Bend, and HERC PPA termination), and Case No. PU-17-322 (Deferred Accounting for Laurentian PPA terminations), this month’s FCR includes \$47,332 in termination cost recovery. 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 Monthly FCR Rate Calculation
- Attachment B – Four Month Fuel Cost Rider Costs
- Attachment C – MISO Day 2 and ASM Settlement Charges
- Attachment D – Replacement Costs for Disallowed Resources and Residential Bill Impact
- Attachment E – Derivation of FCR True-Up Adjustment
- Attachment F – Summary of Credits and Other Adjustment 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 Alex Nisbet at 701-241-8632 or [Alex.J.Nisbet@xcelenergy.com](mailto:Alex.J.Nisbet@xcelenergy.com).

Sincerely,

/ s /

LISA PETERSON  
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures  
cc: Alex Nisbet

Summary of Fuel Cost Rider Rates - September 2025

**System Fuel and Purchased Energy Costs**

1 NSP System Fuel/Energy Costs (Retail)	\$279,319,971	Att B, p. 1, line 6
2 MISO Charges	\$112,873,852	Att B, p. 1, line 10
3 Disallowed Resource Costs	\$10,558,670	Att B, p. 1, line 14
4 Net NSP System Costs	<u>\$402,752,494</u>	

4 Month Total

**ND Fuel and Purchased Energy Costs**

5 NSP System MWh Sales (Retail)	12,454,742	Att B, p. 1, line 16
6 Average NSP System Cost per kWh	3.234¢	line 4 / line 5/10
7 ND MWh Sales (Retail)	633,836	Att B, p. 1, line 18
8 ND Fuel & Purchased Energy Costs	<u>\$20,496,532</u>	line 6 x line 7*10

4 Month Total

**Credits and Other Adjustments Applicable to ND**

9 Wholesale Margins Credit	(\$2,255,027)	Att B, p. 1, line 20,21
10 REC Sales Proceeds Credit	(\$517,122)	Att B, p. 1, line 22
11 Biomass PPA Termination Costs	\$47,332	Att B, p. 1, line 23
12 Net Credits and Other	<u>(\$2,724,816)</u>	

July 2025

**Over/Under Recovered Costs**

13 True-Up Amount for July 2025	\$1,882,505	Att E, p.1, line 19
---------------------------------	-------------	---------------------

Amount

**ND Net FCR Costs**

14 Net FCR Costs	\$19,654,221	line 8+line 12+line 13
15 Net FCR Cost per kWh	3.101¢	line 14 / line 7/10

4 Month Total

**Fuel Cost Rider Rate By Class**

Customer Class	ND Cost of Fuel/kWh	Cust. Class Ratio <sup>1</sup>	FCR Rate
16 Residential	3.101¢	1.0094	<b>3.130¢</b>
17 C & I Non-Demand	3.101¢	1.0129	<b>3.141¢</b>
18 C & I Demand Non-TOD	3.101¢	1.0069	<b>3.122¢</b>
19 C & I Demand TOD On-Peak	3.101¢	1.2181	<b>3.777¢</b>
20 C & I Demand TOD Off-Peak	3.101¢	0.8392	<b>2.602¢</b>
21 Outdoor Lighting	3.101¢	0.7813	<b>2.423¢</b>

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

4 Month Fuel Cost Rider Costs - September 2025

	(A)	(B)	(C)	(D)	(E)
<b>Fuel &amp; Purchased Energy Costs</b>	Apr-25	May-25	Jun-25	Jul-25	4 Month Total
1 Account 151 - Fossil Fuel	\$14,986,912	\$17,316,128	\$25,842,866	\$48,460,163	\$106,606,069
2 Account 518 - Nuclear Fuel	\$8,811,951	\$7,784,297	\$9,987,322	\$10,022,697	\$36,606,267
3 Account 555 - Purchased Power <sup>1</sup>	\$67,577,113	\$44,782,951	\$45,815,101	\$60,604,612	\$218,779,777
4 Sub-Total NSP Sys Energy Costs	\$91,375,976	\$69,883,376	\$81,645,289	\$119,087,472	\$361,992,113
5 Exclude Costs of InterSystem Sales	(\$22,001,733)	(\$14,744,386)	(\$16,012,710)	(\$29,913,313)	(\$82,672,142)
6 Total Sys Fuel & Purch Energy	\$69,374,243	\$55,138,990	\$65,632,579	\$89,174,159	\$279,319,971

<b>MISO Charges</b>					
7a Day 2 Market	\$23,680,292	\$23,948,977	\$21,756,681	\$20,986,175	\$90,372,125
7b MISO Excess Congestion Credit	\$0	\$0	\$0	\$0	\$0
8 Exclude Schedule 24	(\$97,143)	(\$87,196)	(\$102,037)	(\$120,010)	(\$406,386)
9 Ancillary Services Market	\$1,884,723	\$2,056,516	\$1,896,086	\$17,070,788	\$22,908,113
10 Total MISO Charges	\$25,467,872	\$25,918,297	\$23,550,731	\$37,936,953	\$112,873,852

<b>Disallowed Resources Costs<sup>2</sup></b>					
11 Exclude Costs of Disallowed PPAs	(\$8,098,156)	(\$8,225,796)	(\$6,774,544)	(\$7,205,984)	(\$30,304,481)
12 Exclude MISO Revenues	\$2,248,080	\$3,930,725	\$5,307,984	\$8,800,416	\$20,287,206
13a Replacement Energy Costs	\$6,213,107	\$5,839,368	\$4,802,276	\$6,345,925	\$23,200,676
13b Proxy Price Adjustment (St. Paul Cogen)	(\$25,414)	(\$1,188,948)	(\$1,235,447)	(\$174,921)	(\$2,624,730)
14 Net Disallowance	\$337,618	\$355,349	\$2,100,269	\$7,765,436	\$10,558,670
15 Net NSP System Costs	\$95,179,733	\$81,412,635	\$91,283,578	\$134,876,547	\$402,752,494

<b>ND Fuel and Purchased Energy Costs</b>					
	Apr-25	May-25	Jun-25	Jul-25	4 Month Total
16 NSP System Sales (Retail)	2,850,723	2,691,707	3,136,454	3,775,858	12,454,742
17 Avg. NSP System Cost per kWh	3.339¢	3.025¢	2.910¢	3.572¢	3.234¢
18 ND Sales (Retail)	152,780	140,794	152,735	187,527	633,836
19 ND Fuel & Purchased Energy Costs	\$5,101,324	\$4,259,019	\$4,444,589	\$6,698,464	\$20,496,532

<b>Other Adjustments and True-Up</b>					
20 Asset-Based Margins	(\$2,041,623)	(\$2,007,337)	(\$2,077,138)	(\$2,251,361)	
21 Non-Asset-Based Margins	(\$4,122)	(\$4,774)	(\$3,042)	(\$3,666)	
22 REC Sales Proceeds (100%)	(\$1,465,108)	(\$542,643)	(\$1,291,994)	(\$517,122)	
23 Biomass PPA Termination Costs <sup>3</sup>	\$47,779	\$47,629	\$47,480	\$47,332	
24 Net Credits and Other	(\$3,463,073)	(\$2,507,125)	(\$3,324,694)	(\$2,724,816)	

<sup>1</sup> Excludes demand-related expenses, MN Windsource energy costs, and MN Solar Gardens energy costs. October amounts included an one-time credit compensated by a third-party for its building of a new wind project that falls within the restricted boundary of Company's Lake Benton project.

<sup>2</sup> Excludes costs exceeding average system costs for 21 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement (PU-12-813) & other dockets (Dragonfly Solar). Includes Company owned Jeffers Wind, Community Wind North and Rock Aethna wind costs where replacement costs are repriced based on based average system cost. St. Paul Cogen PPA proxy price adjustment based on LMP.

<sup>3</sup> Benson and Laurentian PPAs.

MISO Day 2 Settlement Charges - September 2025

	FERC Account	Retail Expense (Rev)
<b>Energy and Losses</b>		
1 Day Ahead Asset Energy - Energy	555	\$16,866,202
2 Day Ahead Asset Energy - Losses	555	\$9,291,734
3 Day Ahead Financial Bilateral Transaction Loss	555	\$11,122
4 Day Ahead Non-Asset Energy - Energy	555	(\$8,882,965)
5 Day Ahead Non-Asset Energy - Losses	555	\$324,721
6 Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	(\$9,081)
7 Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	\$0
8 Real Time Asset Energy - Energy	555	\$307,687
9 Real Time Asset Energy - Losses	555	(\$6,542)
10 Real Time Distribution of Losses	555	(\$3,388,253)
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	(\$153,672)
14 Real Time Non-Asset Energy - Energy	555	(\$236,367)
15 Real Time Non-Asset Energy - Losses	555	\$15,863
16 <b>Total Energy and Losses</b>		<u>\$14,140,450</u>
<b>Congestion</b>		
17 Day Ahead Asset Energy - Congestion	555	\$12,569,505
18 Day Ahead Financial Bilateral Transaction - Congestion	555	\$56,275
19 Day Ahead Non-Asset Energy - Congestion	555	(\$147,961)
20 Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	(\$57,451)
21 Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	\$0
22 Real Time Asset Energy - Congestion	555	\$19,186
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	(\$18,019)
26 <b>Total Congestion-Related</b>		<u>\$12,421,534</u>
<b>Financial Transmission Rights (FTR)</b>		
27 FTR Hourly Allocation	555	(\$6,792,620)
28 FTR Monthly Allocation	555	(\$244,203)
29 FTR Transaction	555	\$0
30 FTR Yearly Allocation	555	\$0
31 FTR Full Funding Guarantee	555	(\$67,154)
32 FTR Guarantee Uplift	555	\$67,154
33 FTR Monthly Transaction	555	\$0
34 <b>Total Financial Transmission Rights Charges</b>		<u>(\$7,036,823)</u>

MISO Day 2 Settlement Charges - September 2025

	<u>FERC Account</u>	<b>Retail Expense (Rev)</b>
<b>Uplift</b>		
35 Real-Time Revenue Neutrality Uplift	555	\$1,504,134
36 <b>Total Uplift</b>		<u>\$1,504,134</u>
<b>Revenue Sufficiency Guarantee (RSG)</b>		
37 Day Ahead RSG Distribution	555	\$104,038
38 Day Ahead RSG Make Whole Payment	555	(\$7,988)
39 Real time RSG First Pass Distribution	555	\$166,533
40 Real Time RSG Make Whole Payment	555	(\$38,073)
41 Real Time Price Volatility Make Whole Payment	555	(\$9,332)
42 <b>Total Revenue Sufficiency Guarantee</b>	555	<u>\$215,178</u>
<b>Market Administration<sup>1</sup></b>		
43 Day Ahead Market Administration	575.7	\$619,561
44 Real Time Market Administration	575.7	\$69,879
45 FTR Market Administration	575.7	\$11,646
46 <b>Total Market Administration</b>		<u>\$701,086</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	\$5,094,396
51 ARR Monthly Revenue	555	(\$5,094,395)
52 ARR Stage 2 Distribution	555	(\$1,337,318)
53 ARR Monthly Infeasible Revenue	555	\$2,618
54 <b>Total Auction Revenue Rights</b>		<u>(\$1,334,699)</u>
<b>Other Miscellaneous</b>		
55 Real Time Miscellaneous	555	\$255,306
56 Real Time Uninstructed Deviation	555	\$0
57 <b>Total Other Miscellaneous</b>		<u>\$255,306</u>
58 <b>Total MISO Day 2 Charges</b>		<u><u>\$20,866,165</u></u>

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

MISO Ancillary Services Markets (ASM) Charges - September 2025

	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
<b>Procurement</b>		
1 Day Ahead Regulation	555	(\$805,458)
2 Day Ahead Spinning Reserve	555	(\$34,054)
3 Day Ahead Supplemental Reserve	555	(\$758,457)
4 Real Time Regulation	555	\$1,057,145
5 Real Time Spinning Reserve	555	(\$27,761)
6 Real Time Supplemental Reserve	555	\$38,604
7 <b>Total Procurement</b>		<u><u>(\$529,980)</u></u>
<b>Resource Energy</b>		
8 Real Time Excessive Energy	555	(\$26,222)
9 Real Time Excessive Energy - Congestion	555	\$0
10 Real Time Excessive Energy - Losses	555	\$0
11 Real Time Non-Excessive Energy	555	\$13,347,312
12 Real Time Non-Excessive Energy - Congestion	555	\$401,478
13 Real Time Non-Excessive Energy - Losses	555	(\$5,967)
14 Real Time Net Regulation Adjustment	555	(\$21,244)
15 <b>Total Resource Energy</b>		<u><u>\$13,695,357</u></u>
<b>Cost Distribution</b>		
16 Real Time Regulation Reserve Cost Distribution	555	\$253,250
17 Real Time Spinning Reserve Cost Distribution	555	\$187,142
18 Real Time Supplemental Reserve Cost Distribution	555	\$3,341,555
19 <b>Total Cost Distribution</b>		<u><u>\$3,781,946</u></u>
<b>Penalties</b>		
20 Real Time Excessive/Deficient Energy Deployment	555	\$123,465
21 Real Time Contingency Reserve Deployment Failure	555	\$0
22 <b>Total Penalties</b>		<u><u>\$123,465</u></u>
23 <b>Grand Total ASM Charges<sup>2</sup></b>		<u><u>\$17,070,788</u></u>

<sup>2</sup> Included new MISO ASM charges:  
 DA Short Term Reserve Amount  
 RT Short Term Reserve Amount  
 RT Short Term Reserve Distribution Amount  
 Short Term Reserve Deployment Failure Charge  
 Short Term Reserve Procurement  
 RT ST Reserve Gen Alloc Reclass

Derivation of July 2025 Replacement Costs for Disallowed Resources & Residential Bill Impact

	NSP System	ND Allocation <sup>1</sup>	ND Jurisdiction	
<b>Fuel &amp; Purchased Energy Costs</b>				
1 Fuel & Purch Energy Costs (Retail) <sup>2</sup>	\$126,936,191	4.9665%	\$6,304,253	
Disallowed PPA Costs				
2 Disallowed C-BED Wind PPAs <sup>3</sup>	(\$1,596,225)	4.9665%	(\$79,276)	
3 Disallowed Solar PPAs	(\$5,471,948)	4.9665%	(\$271,763)	
4 Curtailment Payments	(\$137,811)	4.9665%	(\$6,844)	
5 Total Exclusion	(\$7,205,984)		(\$357,883)	Line 2 +Line 3+Line 4
6 Adjusted Fuel & Purchased Energy Costs	\$119,730,207	4.9665%	\$5,946,369	Line 1 - line 5
7 MWh Energy Sales	3,775,858	4.9665%	187,527	Att B Line 16,18 (D)
8 Disallowed Resources MWh Energy Sales	177,657	4.9665%	8,823	
9 Adjusted MWh Sales (Billing Mo.)	3,598,201		196,350	
10 Avg. Sys. Cost w/o Disallowed Resources (\$/MWh)	\$33.28		\$30.28	Line 6 / line 9
11 Replacement Cost for Disallowed Resources <sup>4</sup>	(\$5,911,557)		(\$267,200)	Line 8 x line 10
12 Adjusted Fuel & Purch Energy Costs (Retail)	\$119,730,207	4.9665%	\$5,946,369	Line 6
13 Exclude MISO Revenues (Includes Jeffers, Community Wind North & Rock Aetna)	\$8,800,416	4.9665%	\$437,070	Att B Line 12
14 Net System Cost Excludes MISO Revenues	\$128,530,623		6,383,440	Line12 + Line 13
15 Adjusted MWH Sales (Billing Mo.)	3,598,201		196,350	Line 9
16 Adjusted Average System Cost (\$/MWh)	\$35.72		\$32.51	Line 14/Line 9
17 Net Replacement Cost	\$6,345,925		\$286,836	Line 16 * Line 8
<b>ND Residential Bill Impact</b>				
18 Cost Exclusion	(\$7,205,984)		(\$357,883)	Line 5
19 Exclude MISO Revenues	\$8,800,416		\$437,070	Line 13
20 Net Replacement Costs	\$6,345,925		\$286,836	Line 17
21 Net Impact of Disallowance and Repricing	\$7,940,357		\$366,023	Line 18+Line 19+line 20
22 FCR Impact of Disallowance & Repricing/kWh			0.195¢	Line 21 / line 7/10
23 Residential Monthly Bill Impact (750 kWh)			\$1.46	Line 22 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> Cost before disallowed resources excluded and includes MISO charges, less St. Paul Cogen proxy price adjustment.

<sup>3</sup> Originally 15 C-BED PPAs. Two of the C-BED PPAs, Jeffers Wind and Community Wind North, became Company owned facilities in January 2021.

<sup>4</sup> Reflects the average system fuel and purchased energy cost per kWh (excluding the disallowed PPAs, Jeffers Wind, Community Wind North and RcoK Aetna wind costs and volumes) applied to the energy volumes of the disallowed PPAs.

Derivation of FCR True-Up Adjustment - July 2025

**Cost to Recover in July 2025**

	[a] Jul Sys Fuel Cost/kWh <sup>1</sup>	[b] Jul ND MWh Sales <sup>2</sup>	Amount	
1 Fuel & Purchased Energy Costs	3.572¢	187,527	\$6,698,464	
2 True Up Amount for May 2025			\$594,358	
3 Net Costs			<u>\$7,292,822</u>	Line 1 + 2

**Cost Recovered in July 2025**

<u>Fuel &amp; Purchased Energy</u>	<u>Sales</u>	<u>Amount</u>
4 (i) Residential	63,916	\$1,858,724
5 (ii) C & I Non-Demand	7,247	\$211,290
6 (iii) C & I Demand Non-TOD	64,927	\$1,879,156
7 (iv) C & I Demand TOD On-Peak	18,726	\$649,858
8 (v) C & I Demand TOD Off-Peak	31,802	\$760,063
9 (vi) Outdoor Lighting	909	\$20,542
10 Total	<u>187,527</u>	<u>\$5,379,634</u>

**True-Up Obligation**

11 (i) Residential	63,916	\$16,405
12 (ii) C & I Non-Demand	7,247	\$1,473
13 (iii) C & I Demand Non-TOD	64,927	\$11,060
14 (iv) C & I Demand TOD On-Peak	18,726	\$746
15 (v) C & I Demand TOD Off-Peak	31,802	\$995
16 (vi) Outdoor Lighting	909	\$5
17 Total	<u>187,527</u>	<u>\$30,683</u>

18 Net Recovery \$5,410,317 Line 10 + Line 17

**Over/Under Recovered Costs**

19 True-Up Amount for July 2025 \$1,882,505 Line 3 - Line 18

<sup>1</sup> Reflects the average for the month of July 2025.

<sup>2</sup> Actual ND sales in month of July 2025.

<sup>3</sup> Cost adjustments of January 2025 curtailments

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

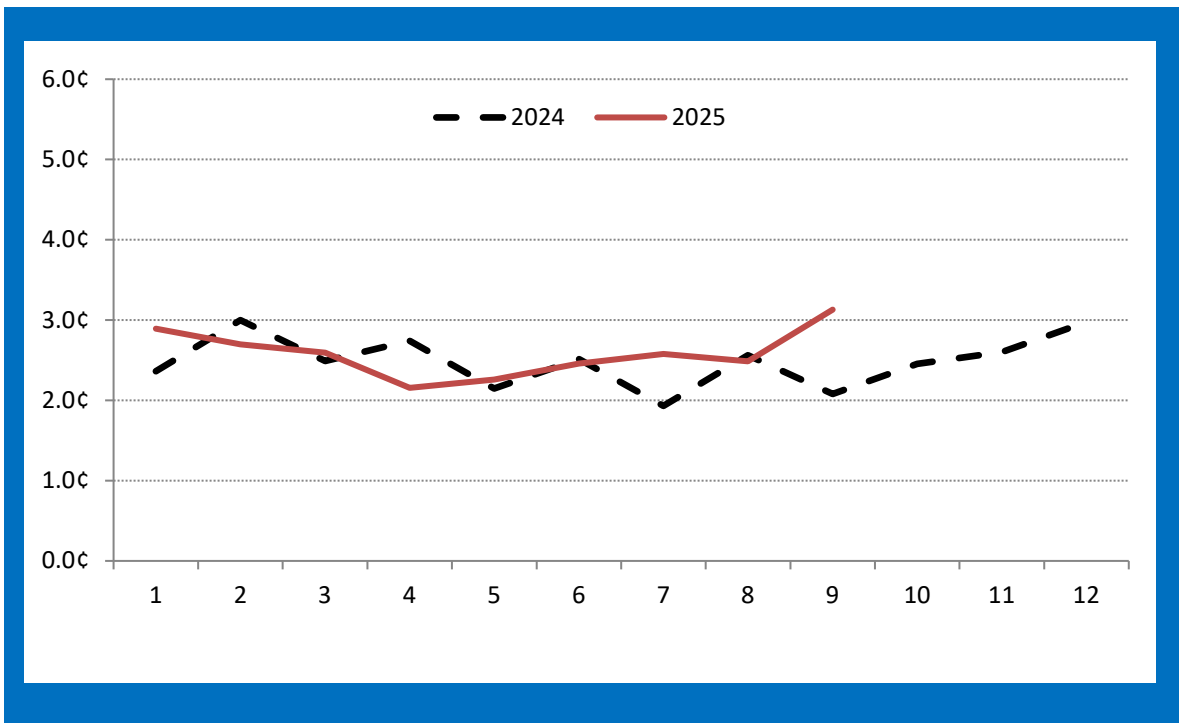
Margin Sharing and REC Sales Credits in Monthly FCR

Month	Asset Based Margins	Non-Asset Based Margins	Renewable Energy Credits	Total
1 January	(\$2,349,376)	(\$7,743)	(\$447,650)	(\$2,804,769)
2 February	(\$2,067,345)	(\$5,474)	(\$1,093,715)	(\$3,166,534)
3 March	(\$2,391,693)	(\$5,847)	(\$503,018)	(\$2,900,558)
4 April	(\$2,041,623)	(\$4,122)	(\$1,465,108)	(\$3,510,853)
5 May	(\$2,007,337)	(\$4,774)	(\$542,643)	(\$2,554,754)
6 June	(\$2,077,138)	(\$3,042)	(\$1,291,994)	(\$3,372,174)
7 July	(\$2,251,361)	(\$3,666)	(\$517,122)	(\$2,772,149)
8 August				\$0
9 September				\$0
10 October				\$0
11 November				\$0
12 December				\$0
13 Total	<b>(\$15,185,873)</b>	<b>(\$34,669)</b>	<b>(\$5,861,249)</b>	<b>(\$21,081,791)</b>

Biomass Contracts Termination Cost Recovery in Monthly FCR

Month	Benson Amortization (Regulatory Asset)	Benson Amortization (Plant Impairment)	Benson ROE (Regulatory Asset)	Benson ROE (Plant Impairment)	Laurentian Payment	Total
	FERC 557	FERC 407	FERC 182.2	FERC 182.3		
14 January	\$19,946	\$22,386	\$2,762	\$3,133	\$0	\$48,226
15 February	\$19,946	\$22,386	\$2,692	\$3,054	\$0	\$48,077
16 March	\$19,946	\$22,386	\$2,622	\$2,975	\$0	\$47,928
17 April	\$19,946	\$22,386	\$2,552	\$2,896	\$0	\$47,779
18 May	\$19,946	\$22,386	\$2,482	\$2,816	\$0	\$47,629
19 June	\$19,946	\$22,386	\$2,412	\$2,737	\$0	\$47,480
20 July	\$19,946	\$22,386	\$2,343	\$2,658	\$0	\$47,332
21 August						\$0
22 September						\$0
23 October						\$0
24 November						\$0
25 December						\$0
26 Total	<b>\$139,620</b>	<b>\$156,699</b>	<b>\$17,865</b>	<b>\$20,269</b>	<b>\$0</b>	<b>\$334,453</b>

### Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges				
	<u>2024</u>	<u>Bill Impact<sup>1</sup></u>	<u>2025</u>	<u>Bill Impact<sup>1</sup></u>
1 January	2.364¢	\$17.73	2.894¢	\$21.70
2 February	2.999¢	\$22.49	2.696¢	\$20.22
3 March	2.492¢	\$18.69	2.594¢	\$19.46
4 April	2.741¢	\$20.55	2.156¢	\$16.17
5 May	2.149¢	\$16.12	2.257¢	\$16.93
6 June	2.513¢	\$18.85	2.457¢	\$18.42
7 July	1.931¢	\$14.48	2.576¢	\$19.32
8 August	2.563¢	\$19.22	2.486¢	\$18.65
9 September	2.078¢	\$15.59	3.130¢	\$23.47
10 October	2.456¢	\$18.42		
11 November	2.600¢	\$19.50		
12 December	<u>2.977¢</u>	<u>\$22.33</u>		
13 Average	2.489¢	\$18.66	2.583¢	\$19.37

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

Community Solar Garden Costs Allocated To North Dakota FCA

	August 2024	September 2024	October 2024	November 2024	December 2024	January 2025	February 2025	March 2025	April 2025	May 2025	June 2025	July 2025	12-Month Total
1 Market Priced Cost	\$6,888,310	\$5,549,300	\$3,939,463	\$2,159,303	(\$4,377,102)	\$2,337,713	\$5,368,165	\$3,810,758	\$12,567,668	\$7,360,444	\$4,327,595	\$14,600,098	\$64,531,716
2 Above Market Cost	\$19,437,935	\$19,408,814	\$15,106,710	\$6,992,427	\$11,002,366	\$9,343,825	\$4,899,285	\$21,100,944	\$9,290,279	\$15,386,786	\$13,671,612	\$11,651,869	\$157,292,852
3 Total Solar Gardens (1)+(2)	\$26,326,245	\$24,958,114	\$19,046,173	\$9,151,730	\$6,625,264	\$11,681,538	\$10,267,450	\$24,911,703	\$21,857,947	\$22,747,230	\$17,999,207	\$26,251,967	\$221,824,568
4 ND Billing Month Sales	194,728	166,146	176,001	136,802	207,679	214,073	206,222	190,857	152,780	140,794	152,735	187,527	2,126,344
5 Billing Month System Sales	3,773,853	3,224,369	3,233,878	2,592,734	3,804,017	3,035,044	3,260,505	3,191,886	2,850,723	2,691,707	3,136,454	3,775,858	38,571,028
6 ND Allocator (4)/(5)	5.15993%	5.15282%	5.44241%	5.27636%	5.45947%	7.05337%	6.32485%	5.97944%	5.35934%	5.23066%	4.86967%	4.96647%	5.51280%
7 Market Costs (1)	\$6,888,310	\$5,549,300	\$3,939,463	\$2,159,303	(\$4,377,102)	\$2,337,713	\$5,368,165	\$3,810,758	\$12,567,668	\$7,360,444	\$4,327,595	\$14,600,098	\$64,531,716
8 ND Solar Gardens Allocation (7)x(6)	\$355,432	\$285,946	\$214,402	\$113,933	(\$238,966)	\$164,888	\$339,528	\$227,862	\$673,544	\$385,000	\$210,740	\$725,110	\$3,457,417