

## **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 February FCR the net MISO Day 2 costs for December as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is \$7,079,679 which is the net of many items. 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 February FCR rates the net MISO ASM costs for December as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is \$1,424,899, 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>2</sup> December margins of \$718,434 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 evenly over the following 12-month period. The North Dakota retail share of the 2017 Non-Asset Based Margin amount applicable to the February FCR is \$3,418. 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

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

<sup>2</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

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. The REC sales credit for the current reporting period is \$80,275. 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>3</sup>
2. Marshall Solar LLC (62.25 MW)<sup>4</sup>
3. North Star Solar PV (100 MW)<sup>5</sup>
4. Aurora Distributed Solar (100 MW)<sup>6</sup>

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<sup>3</sup> Case No. PU-16-458, ORDER REGARDING 2015 POWER PURCHASE AGREEMENT COSTS, October 5, 2016.

<sup>4</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>5</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>6</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 (see table below) are to be excluded from the calculation of the Company’s monthly FCR rates. Beginning with September 2018, a new solar PPA, Dragonfly Solar is added to the exclusion list. 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.

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)

## 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 located 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 February FCR includes \$107,284 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 Calculation of the Monthly 2019 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 /

AMY LIBERKOWSKI  
DIRECTOR, REGULATORY PRICING AND ANALYSIS

CC: David H. Sederquist

Enclosures

Summary of Fuel Cost Rider Rates - February 2019

**System Fuel and Purchased Energy Costs**

1 NSP System Fuel/Energy Costs (Retail)	\$287,282,022	Att B, p. 1, line 6
2 MISO Charges	\$40,571,733	Att B, p. 1, line 10
3 Disallowed Purchased Power Costs	(\$14,131,935)	Att B, p. 1, line 14
4 Net NSP System Costs	<u>\$313,721,820</u>	

4 Month Total

**ND Fuel and Purchased Energy Costs**

5 NSP System MWh Sales (Retail)	13,248,033	Att B, p. 1, line 16
6 Average NSP System Cost per kWh	2.368¢	line 4 / line 5/10
7 ND MWh Sales (Retail)	701,432	Att B, p. 1, line 18
8 ND Fuel & Purchased Energy Costs	<u>\$16,609,910</u>	line 6 x line 7

4 Month Total

**Credits and Other Adjustments Applicable to ND**

9 Wholesale Margins Credit	(\$721,852)	Att B, p. 1, line 20,21
10 REC Sales Proceeds Credit	(\$80,275)	Att B, p. 1, line 22
11 Biomass PPA Termination Costs	\$110,184	Att B, p. 1, line 23
12 Net Credits and Other	<u>(\$691,943)</u>	

December 2018

**Over/Under Recovered Costs**

13 True-Up Amount for December 2018	(\$1,633,013)	Att E, p.1, line 19
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Amount

**ND Net FCR Costs**

14 Net FCR Costs	\$14,284,954	line 8+line 12+line 13
15 Net FCR Cost per kWh	2.037¢	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	2.037¢	0.99690	<b>2.030¢</b>
17 C & I Non-Demand	2.037¢	1.03180	<b>2.101¢</b>
18 C & I Demand Non-TOD	2.037¢	1.01840	<b>2.074¢</b>
19 C & I Demand TOD On-Peak	2.037¢	1.27980	<b>2.606¢</b>
20 C & I Demand TOD Off-Peak	2.037¢	0.79540	<b>1.620¢</b>
21 Outdoor Lighting	2.037¢	0.73410	<b>1.495¢</b>

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

4 Month Fuel Cost Rider Costs - February 2019

	(A)	(B)	(C)	(D)	(E)
	Sep-18	Oct-18	Nov-18	Dec-18	4 Month Total
<b>Fuel &amp; Purchased Energy Costs</b>					
1 Account 151 - Fossil Fuel *	\$42,354,879	\$38,990,862	\$45,454,418	\$43,546,149	\$170,346,308
2 Account 518 - Nuclear Fuel	\$8,491,311	\$7,591,733	\$10,212,886	\$10,920,319	\$37,216,249
3 Account 555 - Purchased Power <sup>1</sup>	\$40,231,985	\$39,924,176	\$29,477,456	\$36,313,937	\$145,947,554
4 Sub-Total NSP Sys Energy Costs	\$91,078,175	\$86,506,771	\$85,144,760	\$90,780,405	\$353,510,111
5 Exclude Costs of InterSystem Sales	(\$15,739,978)	(\$13,833,029)	(\$15,701,935)	(\$20,953,148)	(\$66,228,089)
6 Total Sys Fuel & Purch Energy	\$75,338,198	\$72,673,742	\$69,442,825	\$69,827,257	\$287,282,022
* July & August 2018 costs excluded Benson biomass fuel expenses related to contract termination agreement					
<b>MISO Charges</b>					
7 Day 2 Market	\$7,277,137	\$10,493,511	\$7,436,250	\$7,176,376	\$32,383,275
8 Exclude Schedule 24 Plus Congest Refund	(\$96,619)	(\$101,812)	(\$105,958)	(\$96,697)	(\$401,086)
9 Ancillary Services Market	\$3,421,814	\$2,750,673	\$992,158	\$1,424,899	\$8,589,544
10 Total MISO Charges	\$10,602,332	\$13,142,373	\$8,322,451	\$8,504,577	\$40,571,733
<b>Disallowed PPA Costs<sup>2</sup></b>					
11 Exclude Costs of Disallowed PPAs	(\$6,855,093)	(\$5,851,321)	(\$4,807,234)	(\$4,570,947)	(\$22,084,594)
12 Exclude Related Curtailment Costs	\$2,661	(\$13,988)	(\$22,138)	(\$22,138)	(\$55,602)
13 Replacement Energy Costs	\$2,344,353	\$2,103,515	\$1,924,313	\$1,636,081	\$8,008,262
14 Net Disallowance	(\$4,508,079)	(\$3,761,794)	(\$2,905,058)	(\$2,957,003)	(\$14,131,935)
15 Net NSP System Costs	\$81,432,451	\$82,054,320	\$74,860,217	\$75,374,831	\$313,721,820
<b>ND Fuel and Purchased Energy Costs</b>					
16 NSP System Sales (Retail)	3,439,026	3,450,768	2,945,898	3,412,341	13,248,033
17 Avg. NSP System Cost per kWh	2.368¢	2.378¢	2.541¢	2.209¢	2.368¢
18 ND Sales (Retail)	162,857	173,720	161,751	203,104	701,432
19 ND Fuel & Purchased Energy Costs	\$3,856,454	\$4,131,062	\$4,110,093	\$4,486,342	\$16,609,910
<b>Other Adjustments and True-Up</b>					
20 Asset-Based Margins	(\$841,276)	(\$613,055)	(\$965,465)	(\$718,434)	(\$3,138,230)
21 Non-Asset-Based Margins	(\$24,290)	(\$3,260)	(\$18,417)	(\$3,418)	(\$49,385)
22 REC Sales Proceeds (100%)	(\$253,458)	(\$108,486)	(\$238,292)	(\$80,275)	(\$680,511)
23 Biomass PPA Termination Costs <sup>3</sup>	\$104,592	\$110,184	\$108,018	\$107,284	\$430,078
24 Net Credits and Other	(\$1,014,432)	(\$614,617)	(\$1,114,156)	(\$694,843)	(\$3,438,048)

<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 dockets.

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

MISO Day 2 Settlement Charges - February 2019

	FERC Account	Retail Expense (Rev)
<b>Energy and Losses</b>		
1 Day Ahead Asset Energy - Energy	555	\$3,636,926
2 Day Ahead Asset Energy - Losses	555	\$3,762,248
3 Day Ahead Financial Bilateral Transaction Loss	555	\$3,014
4 Day Ahead Non-Asset Energy - Energy	555	(\$3,534,295)
5 Day Ahead Non-Asset Energy - Losses	555	\$303,203
6 Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	(\$3,014)
7 Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	\$0
8 Real Time Asset Energy - Energy	555	\$2,079,461
9 Real Time Asset Energy - Losses	555	\$15,683
10 Real Time Distribution of Losses	555	(\$1,240,909)
11 Real Time Financial Bilateral Transaction - Losses	555	\$3
12 Real Time Losses Rebate on Carve-out Grandfathered Agreements	555	(\$3)
13 Real Time Net Inadvertent Distribution	555	\$99,170
14 Real Time Non-Asset Energy - Energy	555	\$5,131
15 Real Time Non-Asset Energy - Losses	555	(\$34)
16 <b>Total Energy and Losses</b>		<u><u>\$5,126,584</u></u>
<b>Congestion</b>		
17 Day Ahead Asset Energy - Congestion	555	\$1,507,771
18 Day Ahead Financial Bilateral Transaction - Congestion	555	(\$878)
19 Day Ahead Non-Asset Energy - Congestion	555	\$158,919
20 Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	\$878
21 Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	\$0
22 Real Time Asset Energy - Congestion	555	\$58,538
23 Real Time Financial Bilateral Transaction - Congestion	555	\$13
24 Real Time Congestion Rebate - Carve-out Grandfather Agreements	555	(\$13)
25 Real Time Non-Asset Energy - Congestion	555	\$3
26 <b>Total Congestion-Related</b>		<u><u>\$1,725,230</u></u>
<b>Financial Transmission Rights (FTR)</b>		
27 FTR Hourly Allocation	555	(\$1,167,362)
28 FTR Monthly Allocation	555	(\$80,111)
29 FTR Transaction	555	\$0
30 FTR Yearly Allocation	555	\$0
31 FTR Full Funding Guarantee	555	(\$97,314)
32 FTR Guarantee Uplift	555	\$94,933
33 FTR Monthly Transaction	555	\$0
34 <b>Total Financial Transmission Rights Charges</b>		<u><u>(\$1,249,853)</u></u>

MISO Day 2 Settlement Charges - February 2019

	FERC Account	Retail Expense (Rev)
<b>Uplift</b>		
35 Real-Time Revenue Neutrality Uplift	555	\$484,100
36 <b>Total Uplift</b>		<u>\$484,100</u>
<b>Revenue Sufficiency Guarantee (RSG)</b>		
37 Day Ahead RSG Distribution	555	\$119,041
38 Day Ahead RSG Make Whole Payment	555	(\$75,510)
39 Real time RSG First Pass Distribution	555	\$117,415
40 Real Time RSG Make Whole Payment	555	(\$85,677)
41 Real Time Price Volatility Make Whole Payment	555	(\$28,494)
42 <b>Total Revenue Sufficiency Guarantee</b>	555	<u>\$46,775</u>
<b>Market Administration<sup>1</sup></b>		
43 Day Ahead Market Administration	575.7	\$621,089
44 Real Time Market Administration	575.7	\$39,206
45 FTR Market Administration	575.7	\$15,955
46 <b>Total Market Administration</b>		<u>\$676,250</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	\$1,791,300
51 ARR Monthly Revenue	555	(\$1,788,441)
52 ARR Stage 2 Distribution	555	(\$155,089)
53 ARR Monthly Infeasible Revenue	555	\$42,374
54 <b>Total Auction Revenue Rights</b>		<u>(\$109,855)</u>
<b>Other Miscellaneous</b>		
55 Real Time Miscellaneous	555	\$380,448
56 Real Time Uninstructed Deviation	555	\$0
57 <b>Total Other Miscellaneous</b>		<u>\$380,448</u>
58 <b>Grand Total MISO Day 2 Charges</b>		<u><u>\$7,079,679</u></u>

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

MISO Ancillary Services Markets (ASM) Charges - February 2019

	FERC Account	Retail Expense (Rev)
<b>Procurement</b>		
1 Day Ahead Regulation	555	(\$288,578)
2 Day Ahead Spinning Reserve	555	(\$147,440)
3 Day Ahead Supplemental Reserve	555	(\$24,905)
4 Real Time Regulation	555	\$132,338
5 Real Time Spinning Reserve	555	\$69,092
6 Real Time Supplemental Reserve	555	\$2,791
7 <b>Total Procurement</b>		<u>(\$256,702)</u>
<b>Resource Energy</b>		
8 Real Time Excessive Energy	555	(\$92,894)
9 Real Time Excessive Energy - Congestion	555	\$0
10 Real Time Excessive Energy - Losses	555	\$0
11 Real Time Non-Excessive Energy	555	\$1,340,647
12 Real Time Non-Excessive Energy - Congestion	555	\$10,204
13 Real Time Non-Excessive Energy - Losses	555	\$1,899
14 Real Time Net Regulation Adjustment	555	\$4,554
15 <b>Total Resource Energy</b>		<u>\$1,264,410</u>
<b>Cost Distribution</b>		
16 Real Time Regulation Reserve Cost Distribution	555	\$161,494
17 Real Time Spinning Reserve Cost Distribution	555	\$146,531
18 Real Time Supplemental Reserve Cost Distribution	555	\$23,646
19 <b>Total Cost Distribution</b>		<u>\$331,672</u>
<b>Penalties</b>		
20 Real Time Excessive/Deficient Energy Deployment	555	\$85,519
21 Real Time Contingency Reserve Deployment Failure	555	\$0
22 <b>Total Penalties</b>		<u>\$85,519</u>
23 <b>Grand Total ASM Charges</b>		<u><u>\$1,424,899</u></u>

**Derivation of December 2018 Replacement Costs for Disallowed PPAs**

	<u>NSP System</u>	<u>ND Allocation<sup>1</sup></u>	<u>ND Jurisdiction</u>	
<b>Fuel &amp; Purchased Energy Costs</b>				
1 Fuel & Purch Energy Costs (Retail) <sup>2</sup>	\$77,831,474	5.9520%	\$4,632,563	Att B, Col D, line 6+10
Disallowed PPA Costs				
2 15 C-BED Wind PPAs	(\$3,940,250)	5.9520%	(\$234,525)	
3 7 Solar PPAs	(\$630,696)	5.9520%	(\$37,539)	
4 Wind Curtailment Payments	(\$22,138)	5.9520%	(\$1,318)	
5 Total Exclusion	(\$4,593,084)		(\$273,382)	
6 Adjusted Fuel & Purchased Energy Costs	\$73,238,390	5.9520%	\$4,359,180	Line 1 - line 5
<b>Energy Sales (Billing Mo.)</b>				
7 MWh Energy Sales	[a] 3,412,341	[b] 5.9520%	[c] 203,104	[b]=[c]/[a]
8 Disallowed PPA MWh Energy Sales	(74,607)	5.9520%	(4,441)	
9 Adjusted MWh Sales (Billing Mo.)	3,337,734		198,663	
<b>Replacement Costs</b>				
10 Avg. Cost (\$/MWh) w/o Disallowed PPAs	\$21.94		\$21.94	Line 6 / line 9
11 Replacement Cost for Disallowed PPAs <sup>3</sup>	\$1,636,883		\$97,436	Line 8 x line 10
<b>Impact of Disallowance</b>				
12 Net Impact of Disallowance	(\$2,956,201)		(\$175,947)	Line 5 + line 11
13 FCR Rate Impact of Disallowance /kWh			-0.087¢	Line 12 / line 7
14 Residential Monthly Bill Impact (750 kWh)			(\$0.65)	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 - December 2018

**Cost to Recover in December 2018**

	[a] Dec Sys Fuel Cost/kWh <sup>1</sup>	[b] Dec ND MWh Sales <sup>2</sup>	Amount	
1 Fuel & Purchased Energy Costs	2.209¢	203,104	\$4,486,567	
2 True Up Amount for October 2018			(\$1,168,839)	
3 Net Costs			<u>\$3,317,728</u>	Line 1 + Line 2

**Cost Recovered in December 2018**

	<u>Sales</u>	<u>Amount</u>
4 <u>Fuel &amp; Purchased Energy</u>		
(i) Residential	72,531	\$1,714,821
5 (ii) C & I Non-Demand	10,372	\$253,993
6 (iii) C & I Demand Non-TOD	64,490	\$1,559,218
7 (iv) C & I Demand TOD On-Peak	21,381	\$653,351
8 (v) C & I Demand TOD Off-Peak	32,487	\$614,606
9 (vi) Outdoor Lighting	1,843	\$32,132
10 Total	<u>203,104</u>	<u>\$4,828,121</u>

True-Up Obligation

11 (i) Residential	72,531	\$48,027
12 (ii) C & I Non-Demand	10,372	\$6,763
13 (iii) C & I Demand Non-TOD	64,490	\$40,158
14 (iv) C & I Demand TOD On-Peak	21,381	\$13,237
15 (v) C & I Demand TOD Off-Peak	32,487	\$12,914
16 (vi) Outdoor Lighting	1,843	\$1,521
17 Total	<u>203,104</u>	<u>\$122,620</u>

18 Net Recovery		<u>\$4,950,741</u>	Line 10 + Line 17
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**Over/Under Recovered Costs**

19 True-Up Amount for December 2018		<u>(\$1,633,013)</u>	Line 3 - Line 18
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<sup>1</sup> Reflects the average for the month of December 2018.

<sup>2</sup> Actual ND sales in month of December 2018.

<sup>3</sup> Correction for August Recovery Data Entry Error in October FCR.

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

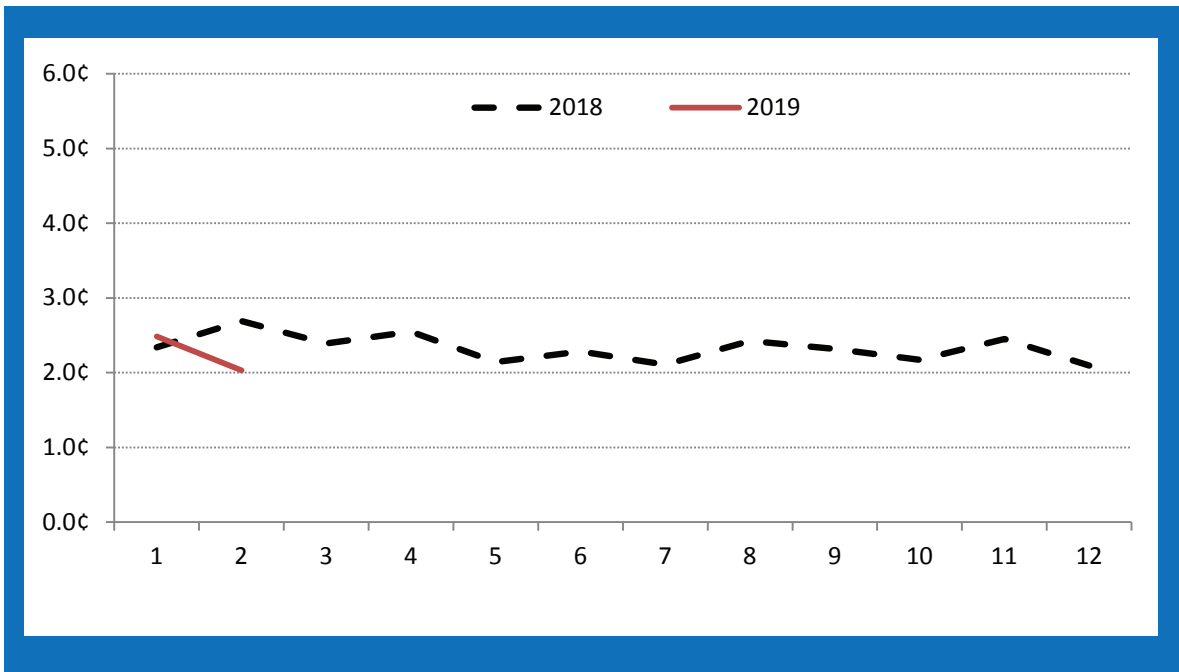
Margin Sharing and REC Sales Proceeds Credits

Month	Asset Based Margins	Non-Asset Based Margins	Renewable Energy Credits	Total
1 January	(\$859,055)	\$16	(\$31,442)	(\$890,482)
2 February	(\$702,407)	(\$9,247)	(\$40,688)	(\$752,343)
3 March	(\$839,181)	(\$55,224)	(\$23,814)	(\$918,219)
4 April	(\$691,452)	(\$7,458)	(\$232,314)	(\$931,225)
5 May	(\$861,773)	(\$43,601)	(\$449,151)	(\$1,354,525)
6 June	(\$752,150)	(\$6,381)	(\$180,234)	(\$938,765)
7 July	(\$878,759)	(\$31,635)	(\$335,020)	(\$1,245,413)
8 August	(\$629,799)	(\$4,469)	(\$131,393)	(\$765,661)
9 September	(\$841,276)	(\$24,290)	(\$253,458)	(\$1,119,024)
10 October	(\$613,055)	(\$3,260)	(\$108,486)	(\$724,801)
11 November	(\$965,465)	(\$18,417)	(\$238,292)	(\$1,222,174)
12 December	(\$718,434)	(\$3,418)	(\$80,275)	(\$802,127)
13 Cumulative	<b>(\$9,352,807)</b>	<b>(\$207,384)</b>	<b>(\$2,104,568)</b>	<b>(\$11,664,759)</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							
15 February							
16 March							
17 April							
18 May							
19 June							
20 July	\$22,953	\$20,786	\$31,695	\$30,010	\$877,938	\$1,836	\$985,218
21 August	\$21,140	\$20,786	\$31,695	\$29,030	\$0	\$1,964	\$104,615
22 September	\$20,719	\$20,786	\$31,965	\$29,030	\$0	\$2,092	\$104,592
23 October	\$20,786	\$24,913	\$31,965	\$30,784	\$0	\$1,736	\$110,184
24 November	\$22,223	\$20,786	\$31,965	\$31,366	\$0	\$1,678	\$108,018
25 December	\$20,708	\$20,786	\$31,965	\$31,569	\$0	\$2,256	\$107,284
26 Cumulative	<b>\$128,529</b>	<b>\$128,843</b>	<b>\$191,250</b>	<b>\$181,789</b>	<b>\$877,938</b>	<b>\$11,562</b>	<b>\$1,519,911</b>

### Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges				
	2018	Bill Impact <sup>1</sup>	2019	Bill Impact <sup>1</sup>
1 January	2.341¢	\$17.56	2.486¢	\$18.65
2 February	2.691¢	\$20.18	2.030¢	\$15.23
3 March	2.392¢	\$17.94		
4 April	2.548¢	\$19.11		
5 May	2.144¢	\$16.08		
6 June	2.282¢	\$17.12		
7 July	2.108¢	\$15.81		
8 August	2.426¢	\$18.20		
9 September	2.318¢	\$17.39		
10 October	2.171¢	\$16.28		
11 November	2.451¢	\$18.38		
12 December	2.093¢	\$15.70		
13 Average	2.330¢	\$17.48	2.258¢	\$16.94

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

Community Solar Garden Costs Allocated To North Dakota FCA

	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	12-Month Total
1 Market Priced Cost	\$774,649	\$708,550	\$833,890	\$1,403,964	\$2,080,074	\$1,591,746	\$2,363,416	\$2,082,538	\$1,703,371	\$1,342,849	(\$320,333)	\$1,769,155	\$16,333,869
2 Above Market Cost	\$2,023,834	\$1,910,837	\$5,048,402	\$5,548,760	\$5,580,368	\$5,026,916	\$7,826,811	\$4,911,139	\$5,731,902	\$5,050,152	\$3,994,342	\$2,828,022	\$55,481,485
3 Total Solar Gardens (1)+(2)	\$2,798,483	\$2,619,387	\$5,882,292	\$6,952,724	\$7,660,442	\$6,618,662	\$10,190,227	\$6,993,677	\$7,435,273	\$6,393,000	\$3,674,009	\$4,597,177	\$71,815,354
4 ND Billing Month Sales	249,027	198,296	212,774	178,066	169,590	175,959	193,528	202,286	162,857	173,720	161,751	203,104	2,280,958
5 Billing Month System Sales	3,953,973	3,255,949	3,476,022	3,108,286	3,159,098	3,542,386	3,986,141	4,035,254	3,439,026	3,450,768	2,945,898	3,412,341	41,765,142
6 ND Allocator (4)/(5)	6.29815%	6.09027%	6.12119%	5.72875%	5.36830%	4.96725%	4.85502%	5.01297%	4.73556%	5.03424%	5.49072%	5.95204%	5.46139%
7 Market Costs (1)	\$774,649	\$708,550	\$833,890	\$1,403,964	\$2,080,074	\$1,591,746	\$2,363,416	\$2,082,538	\$1,703,371	\$1,342,849	(\$320,333)	\$1,769,155	\$16,333,869
8 ND Solar Gardens Allocation (7)/(6)	\$48,789	\$43,153	\$51,044	\$80,430	\$111,665	\$79,066	\$114,744	\$104,397	\$80,664	\$67,602	(\$17,589)	\$105,301	\$780,241