



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

December 30, 2015

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

**Re: January 2016 Fuel Cost Charge**

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric fuel cost charge (FCC) for January 2016.

The table below shows the Fuel Cost Charge by customer class category:

<b>January 2016</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02148
<b>C &amp; I Non-Demand</b>	0.02223
<b>C &amp; I Demand</b>	0.02194
<b>C &amp; I Demand Time of Day On-Peak</b>	0.02757
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.01714
<b>Outdoor Lighting</b>	0.01582

## **MISO CHARGES IMPLEMENTATION**

### MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO, formerly Midwest Independent Transmission System Operator, Inc.) charges under the Day 2 Market. Pursuant to the Commission's April 6, 2005 Order in Case No. PU-05-147 and the Order in Case No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The current FCC also reflected the MISO Day 2 charge types including 3 Auction Revenue Rights (ARR) and 3 Financial Transmission Rights (FTR) charge types.<sup>1</sup> Consistent with this Order and the required "net" accounting of Day 2 costs and revenues, we have included in the January 2016 FCC the net MISO Day 2 costs for November 2015 as recorded in Account 555. The MISO Day 2 cost recovery included in this January 2016 FCC is \$7,053,357, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed records in Attachment 2, page 1 to support the calculation of the MISO Day 2 costs.

### MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (ASM) on January 6, 2009, the net costs or revenues of 14 ASM charge types are included in the Fuel Cost Rider, 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 include in the January 2016 FCC the net MISO ASM costs for November 2015 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is \$3,805,517, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

## **SPENT NUCLEAR FUEL DISPOSAL FEE**

The Company received notification from the U.S. Department of Energy (DOE) on May 12, 2014 that the Spent Nuclear Fuel Disposal Fee, which was 1.0 mill per kilowatt hour of electricity generated and sold, would be discontinued effective May 16, 2014.<sup>2</sup> The Disposal Fee is an authorized component of FERC account 518. The charge had been collected from customers via a line item in our monthly Fuel Cost Charge filings. We no longer collect the Disposal Fee from customers and will not do so unless, of course, the DOE reinstates a fee.

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

<sup>2</sup> The Company submitted an informational filing to the Commission on May 21, 2014 regarding this charge in Case No. PU-14-012.

## **REFUNDS**

### Asset and Non-Asset Based Margins Sharing Refund

Under the terms of the Revised Second Amended Settlement adopted by the Commission<sup>3</sup> on February 26, 2014, retroactive to January 1, 2014, the Company began passing through 100 percent of wholesale asset based margins to North Dakota customers. The Asset Based Margin amount of \$269,298 has been included as a credit to the January 2016 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the prior year retail share of the Non-Asset Based Margins has been credited to the monthly FCC over the following 12-month period only if the calendar year balance is positive. The realized North Dakota retail share of the 2014 Non-Asset Based Margin credit is \$194,148 and this credit amount is distributed equally each month over the following 12-month period. The refund reflected in the January 2016 FCC is \$12,776, or a credit of 0.006¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

### Sales of Renewable Energy Credits

Pursuant to the Commission Order dated September 9, 2010 in Case No. PU-10-19, the Company is authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the net proceeds back to customers through the Fuel Cost Rider (FCR). Under the February 26, 2014 Settlement, instead of 90 percent, 100 percent of the North Dakota state jurisdictional share of revenue generated by the sale of Renewable Energy Credits was credited to customers. (See Attachment 3, page 3).

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

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement (Case No. PU-12-813) the following procedural changes reflected in Revised Second Amended Settlement were intended 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 the Fuel Cost Charges. In addition, the Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year.
- Future renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will require approval of an Advance Determination of Prudence before included for recovery in the FCR; and

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<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

- MISO market energy purchases are not subject to the above requirements.

For the January 2016 FCR reporting month there are no new renewable projects or purchases that require the above referenced reporting obligation. The Company will monitor and comply with these obligations under the Settlement going forward.

### **PRAIRIE ROSE WIND PPA**

Pursuant to the Commission's December 21, 2012 Order in the Company's Advance Determination of Prudence application (Case No. PU-12-59), the energy and costs associated with the January 1, 2013 commencement of the Prairie Rose Wind (PRW) power purchase agreement (PPA) are being excluded from the calculation of the Company's monthly FCR.

As a result of the Revised Second Amended Settlement adopted by the Commission on February 26, 2014, the Prairie Rose Wind energy costs incurred on and after February 26, 2014 would be included in the FCR calculation, and the Company would forego any unrecovered portion the Prairie Rose PPA had incurred prior to that time. As such, starting with the May 2014 FCC, the Company has included the Prairie Rose PPA costs in the computation.

### **MONTHLY CALCULATIONS AND COMPARISONS**

Attached is the calculation of the January 2016 FCC, as well as a statistical summary of energy sources and costs, compared to the previous month.

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist at 701-241-8632.

Sincerely,

/ s /

Amy S. Fredregill  
RESOURCE PLANNING AND STRATEGY MANAGER

Enclosures (2)  
CC: David H. Sederquist

Northern States Power Company  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Jan-2016

Jan-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	<b>\$0.02658</b>	<b>-\$0.00168</b>	<b>-\$0.00335</b>	<b>\$0.02155</b>
<b>Residential</b>	<b>\$0.02650</b>	<b>-\$0.00167</b>	<b>-\$0.00334</b>	<b>\$0.02148</b>
<b>C &amp; I Non-Demand</b>	<b>\$0.02743</b>	<b>-\$0.00173</b>	<b>-\$0.00346</b>	<b>\$0.02223</b>
<b>C &amp; I Demand Non-TOD</b>	<b>\$0.02707</b>	<b>-\$0.00171</b>	<b>-\$0.00342</b>	<b>\$0.02194</b>
<b>C &amp; I Demand TOD On-Peak</b>	<b>\$0.03402</b>	<b>-\$0.00215</b>	<b>-\$0.00429</b>	<b>\$0.02757</b>
<b>C &amp; I Demand TOD Off-Peak</b>	<b>\$0.02114</b>	<b>-\$0.00134</b>	<b>-\$0.00267</b>	<b>\$0.01714</b>
<b>Outdoor Lighting</b>	<b>\$0.01951</b>	<b>-\$0.00123</b>	<b>-\$0.00246</b>	<b>\$0.01582</b>
<b>Residential</b>				
Residential Service	\$ 0.02650	\$ (0.00167)	\$ (0.00334)	\$ 0.02148
Residential TOD	\$ 0.02650	\$ (0.00167)	\$ (0.00334)	\$ 0.02148
Residential - Underground	\$ 0.02650	\$ (0.00167)	\$ (0.00334)	\$ 0.02148
Residential TOD - Underground	\$ 0.02650	\$ (0.00167)	\$ (0.00334)	\$ 0.02148
Energy Control - (Non-Demand)	\$ 0.02650	\$ (0.00167)	\$ (0.00334)	\$ 0.02148
Limit Off Peak	\$ 0.02650	\$ (0.00167)	\$ (0.00334)	\$ 0.02148
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
Limit Off Peak	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
Small General Service	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
Small General TOD - Metered	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
Small General TOD - Unmetered	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
Fire and Civil Defense Siren	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
Direct Current (Closed)	\$ 0.02743	\$ (0.00173)	\$ (0.00346)	\$ 0.02223
<b>C &amp; I Demand</b>				
General Service	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
General TOD - On Peak	\$ 0.03402	\$ (0.00215)	\$ (0.00429)	\$ 0.02757
General TOD - Off Peak	\$ 0.02114	\$ (0.00134)	\$ (0.00267)	\$ 0.01714
Peak Controlled (Closed)	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
Peak Controlled TOD (Closed) - On Peak	\$ 0.03402	\$ (0.00215)	\$ (0.00429)	\$ 0.02757
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02114	\$ (0.00134)	\$ (0.00267)	\$ 0.01714
Peak Controlled Tiered	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
Peak Controlled Tiered TOD - On Peak	\$ 0.03402	\$ (0.00215)	\$ (0.00429)	\$ 0.02757
Peak Controlled Tiered TOD - Off Peak	\$ 0.02114	\$ (0.00134)	\$ (0.00267)	\$ 0.01714
Energy Controlled (Closed)	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
Tier 1 Energy Controlled Rider	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
Real Time Pricing - Firm - On Peak	\$ 0.03402	\$ (0.00215)	\$ (0.00429)	\$ 0.02757
Real Time Pricing - Firm - Off Peak	\$ 0.02114	\$ (0.00134)	\$ (0.00267)	\$ 0.01714
Real Time Pricing - Controllable - On Peak	\$ 0.03402	\$ (0.00215)	\$ (0.00429)	\$ 0.02757
Real Time Pricing - Controllable - Off Peak	\$ 0.02114	\$ (0.00134)	\$ (0.00267)	\$ 0.01714
Small Municipal Pumping	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
Municipal Pumping	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
Excess Energy - St. Anthony Falls	\$ 0.02707	\$ (0.00171)	\$ (0.00342)	\$ 0.02194
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01951	\$ (0.00123)	\$ (0.00246)	\$ 0.01582
Street Lighting System	\$ 0.01951	\$ (0.00123)	\$ (0.00246)	\$ 0.01582
Street Lighting Energy	\$ 0.01951	\$ (0.00123)	\$ (0.00246)	\$ 0.01582
Street Lighting Energy - Metered	\$ 0.01951	\$ (0.00123)	\$ (0.00246)	\$ 0.01582
Street Lighting Energy (Closed)	\$ 0.01951	\$ (0.00123)	\$ (0.00246)	\$ 0.01582
Street Lighting - City of St. Paul	\$ 0.01951	\$ (0.00123)	\$ (0.00246)	\$ 0.01582

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Aug-15	Sep-15	Oct-15	Nov-15	4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$43,763,755	\$40,783,629	\$38,217,497	\$35,333,247	\$158,098,128
Account 518 - Nuclear Fuel	\$10,914,377	\$10,542,939	\$9,063,923	\$5,996,735	\$36,517,974
Account 555 - Purchased Power <sup>1</sup>	\$43,392,191	\$43,738,693	\$40,306,305	\$41,877,757	\$169,314,946
MISO Day 2 Charges	\$8,786,957	\$7,761,624	\$3,645,674	\$10,046,285	\$30,240,540
MISO Day 2 - Schedule 24	(\$86,528)	(\$90,239)	(\$88,223)	(\$73,445)	(\$338,434)
MISO - ASM Charges	\$2,020,069	\$886,033	\$1,630,903	\$886,033	\$5,423,039
Account 555 - Total MISO Charges	\$10,720,498	\$8,557,419	\$5,188,354	\$10,858,873	\$35,325,144
Financial Instruments	\$0	\$0	\$0	\$0	\$0
<b>Total System Costs</b>	<b>\$108,790,821</b>	<b>\$103,622,680</b>	<b>\$92,776,079</b>	<b>\$94,066,612</b>	<b>\$399,256,192</b>
Less Fuel Cost of InterSystem Sales	(\$7,792,001)	(\$9,309,967)	(\$10,060,412)	(\$5,175,231)	(\$32,337,611)
<b>Net System Costs</b>	<b>\$100,998,820</b>	<b>\$94,312,713</b>	<b>\$82,715,668</b>	<b>\$88,891,381</b>	<b>\$366,918,582</b>
<b>System MWh Sales</b>					
Total NSP System Retail	3,883,223	3,665,023	3,365,965	2,890,835	13,805,046
Non-Gen Muni's/Load Pattern	-	-	-	-	-
<b>Total NSP System MWh Sales</b>	<b>3,883,223</b>	<b>3,665,023</b>	<b>3,365,965</b>	<b>2,890,835</b>	<b>13,805,046</b>
<b>Average Unit Cost of Fuel and Purchased Power</b>					
<b>Fuel Cost per kWh for NSP System</b>	<b>2.601¢</b>	<b>2.573¢</b>	<b>2.457¢</b>	<b>3.075¢</b>	<b>2.658¢</b>
<b>Class Ratio/TOD Ratio</b>					
(i) Residential	0.9969	0.9969	0.9969	0.9969	0.9969
(ii) C & I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318
(iii) C & I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184
(iv) C & I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798
(v) C & I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954
(vi) Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341
<b>North Dakota Fuel Cost Factor (FCF)</b>					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			2.658¢	0.9969	2.650¢
(ii) C & I Non-Demand			2.658¢	1.0318	2.743¢
(iii) C & I Demand Non-TOD			2.658¢	1.0184	2.707¢
(iv) C & I Demand TOD On-Peak			2.658¢	1.2798	3.402¢
(v) C & I Demand TOD Off-Peak			2.658¢	0.7954	2.114¢
(vi) Outdoor Lighting			2.658¢	0.7341	1.951¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	63,282	57,422	50,103	45,184	215,991
(ii) C & I Non-Demand	8,697	8,324	8,075	7,195	32,291
(iii) C & I Demand Non-TOD	68,054	65,517	65,024	55,348	253,943
(iv) C & I Demand TOD On-Peak	19,995	20,010	18,112	16,463	74,580
(v) C & I Demand TOD Off-Peak	30,354	31,313	28,370	25,828	115,865
(vi) Outdoor Lighting	1,169	1,384	1,546	1,785	5,884
<b>(vii) Total</b>	<b>191,551</b>	<b>183,970</b>	<b>171,230</b>	<b>151,803</b>	<b>698,554</b>
<b>Jan-2016 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Sep-15 Balance of Unrecovered Expenses)					Total
					Sep-15
					(\$1,810,929)

<sup>1</sup> Excludes demand-related expenses

Prior Expenses Recovered in Nov-2015 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	45,184	(\$26,336)
(ii) C & I Non-Demand	7,195	(\$3,509)
(iii) C & I Demand Non-TOD	55,348	(\$29,183)
(iv) C & I Demand TOD On-Peak	16,463	(\$9,889)
(v) C & I Demand TOD Off-Peak	25,828	(\$9,473)
(vi) Outdoor Lighting	1,785	\$13
(vii) Total	151,803	(\$78,377)

Actual Cost Should Have Been Recovered in Nov-15				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.075¢	0.000¢	151,803	\$4,667,942

Cost Recovered in Nov-15 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	45,184	\$1,216,601
(ii) C & I Non-Demand	7,195	\$201,055
(iii) C & I Demand Non-TOD	55,348	\$1,528,204
(iv) C & I Demand TOD On-Peak	16,463	\$570,665
(v) C & I Demand TOD Off-Peak	25,828	\$556,394
(vi) Outdoor Lighting	1,785	\$35,731
(vii) Total	151,803	\$4,108,650

Total Balance of Unrecovered Expenses (Jan-16 Balance of Unrecovered Expenses)	
Jan-2016 Recovery Provision	(\$1,173,260)
4 Month ND Retail Total MWh Sales	698,554
<b>Jan-2016 Recovery Provision per KWH</b>	<b>-0.168¢</b>

Jan-2016 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	-0.168¢	-0.167¢
(ii) C & I Non-Demand	1.0318	-0.168¢	-0.173¢
(iii) C & I Demand Non-TOD	1.0184	-0.168¢	-0.171¢
(iv) C & I Demand TOD On-Peak	1.2798	-0.168¢	-0.215¢
(v) C & I Demand TOD Off-Peak	0.7954	-0.168¢	-0.134¢
(vi) Outdoor Lighting	0.7341	-0.168¢	-0.123¢

Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
<b>Refund/Special Charge Amount</b>	(\$269,298)	(\$12,776)	(\$487,641)	(\$769,715)
(i) Residential	-0.117¢	-0.006¢	-0.212¢	-0.334¢
(ii) C & I Non-Demand	-0.121¢	-0.006¢	-0.219¢	-0.346¢
(iii) C & I Demand Non-TOD	-0.120¢	-0.006¢	-0.216¢	-0.342¢
(iv) C & I Demand TOD On-Peak	-0.150¢	-0.007¢	-0.272¢	-0.429¢
(v) C & I Demand TOD Off-Peak	-0.093¢	-0.004¢	-0.169¢	-0.267¢
(vi) Outdoor Lighting	-0.086¢	-0.004¢	-0.156¢	-0.246¢

Jan-2016 Factors	
	Total
(i) Residential	2.148¢
(ii) C & I Non-Demand	2.223¢
(iii) C & I Demand Non-TOD	2.194¢
(iv) C & I Demand TOD On-Peak	2.757¢
(v) C & I Demand TOD Off-Peak	1.714¢
(vi) Outdoor Lighting	1.582¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Dec-15	Jan-16	Differ- ence	Percent Change	FCA Application Dec-15	Jan-16	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$176.3	\$158.1	(\$18.2)	-10.3%	42.3%	39.6%	-2.7%
2 Nuclear	\$41.4	\$36.5	(\$4.9)	-11.9%	10.0%	9.1%	-0.9%
3 Purchases	\$168.8	\$169.3	\$0.5	0.3%	40.6%	42.4%	1.8%
MISO related Purchases	\$29.7	\$35.3	\$5.6	18.7%	7.1%	8.8%	1.7%
4 Total System Costs	416.3	399.3	(\$17.1)	-4.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$35.4	\$32.3	(\$3.0)	-8.6%	8.5%	8.1%	-0.4%
6 Net System Costs	\$380.9	\$366.9	(\$14.0)	-3.7%	91.5%	91.9%	0.4%
7							
<b>** GWH OUTPUT **</b>							
9 Fossil	5,073	4,665	(408)	-8.0%	31.0%	30.3%	-0.7%
10 Nuclear	4,862	4,355	(507)	-10.4%	29.8%	28.3%	-1.5%
11 Purchases	3,256	3,607	351	10.8%	19.9%	23.5%	3.6%
12 Hydro & Other	2,663	2,403	(260)	-9.8%	16.3%	15.6%	-0.7%
13 Net Interchange	486	344	(142)	-29.2%	3.0%	2.2%	-0.8%
14 Total Output	16,340	15,374	(966)	-5.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,635	1,610	(25)	-1.5%	10.0%	10.5%	0.5%
16 Native Requirement	14,705	13,764	(941)	-6.4%	90.0%	89.5%	-0.5%
17							
<b>** COST per KWH OUTPUT (¢) **</b>							
19 Fossil	3.475	3.389	-0.086	-2.5%			
20 Nuclear	0.852	0.839	-0.014	-1.6%			
21 Purchases	5.185	4.694	-0.491	-9.5%			
22 Total System Costs	2.548	2.597	0.049	1.9%			
23 Intersystem Sales	2.163	2.008	-0.155	-7.1%			
24 Net System Costs	2.591	2.666	0.075	2.9%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,742	13,805	(937)	-6.4%			
28							
29 COST per KWH SALES (¢)	2.584	2.658	0.074	2.9%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.033	-0.168	-0.201				
(i) Residential	0.032	-0.167	-0.200				
(ii) C & I Non-Demand	0.034	-0.173	-0.207				
(iii) C & I Demand Non-TOD	0.033	-0.171	-0.204				
(iv) C & I Demand TOD On-Peak	0.042	-0.215	-0.257				
(v) C & I Demand TOD Off-Peak	0.026	-0.134	-0.159				
(vi) Outdoor Lighting	0.024	-0.123	-0.147				
32 REFUND	0.224	-0.335	-0.559				
(i) Residential	0.225	-0.334					
(ii) C & I Non-Demand	0.230	-0.346					
(iii) C & I Demand Non-TOD	0.228	-0.342					
(iv) C & I Demand TOD On-Peak	0.289	-0.429					
(v) C & I Demand TOD Off-Peak	0.177	-0.267					
(vi) Outdoor Lighting	0.167	-0.246					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.841	2.155	-0.686	-24.1%			
(i) Residential	2.832	2.148	-0.684				
(ii) C & I Non-Demand	2.931	2.223					
(iii) C & I Demand Non-TOD	2.893	2.194					
(iv) C & I Demand TOD On-Peak	3.635	2.757					
(v) C & I Demand TOD Off-Peak	2.259	1.714					
(vi) Outdoor Lighting	2.085	1.582					

**Residential BILL IMPACT (\$'s)**

Calculations:

		Change from kWh Previous Month
[ 4 ] = [1]+[2]+[3]	[21] = [3] / [11]	
[ 6 ] = [4] - [5]	[22] = [4] / [14]	100 (\$0.68)
[14] = [9]+..+[13]	[23] = [5] / [15]	250 (\$1.71)
[16] = [14] - [15]	[24] = [6] / [16]	500 (\$3.42)
[19] = [1] / [9]	[29] = [6] / [27]	750 (\$5.13)
[20] = [2] / [10]	[33] = [29]+[31]	1,000 (\$6.84)

Some miscellaneous totals refer to so many terms that their formula would be too long. So intermediate totals are developed here, then an overall total is taken and is rounded, and finally it's simply referred to above.

	<u>FCA Application</u>	
	Dec-15	Jan-16
<b>** GWH OUTPUT **</b>		
Thermal	2,182,059	1,811,406
Disper gen	(57)	(75)
Hydro plus Wind	480,717	591,255
Hydro and Other	2,662,719	2,402,586
Rounded to nearest thousand:	2,663	2,403
<b>Sales</b>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,635,396,000	1,610,142,000
Rounded to nearest million:	1635.396	1610.142

		System	Intersystem	Retail
<b>November 2015 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 4,857,047.65	\$ 2,263,598.27	\$ 7,120,645.92
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,308,182.43	\$ -	\$ 2,308,182.43
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 563.53	\$ -	\$ 563.53
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (5,967,760.53)	\$ -	\$ (5,967,760.53)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 588,179.30	\$ -	\$ 588,179.30
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (563.53)	\$ -	\$ (563.53)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 10,824.40	\$ 895,920.02	\$ 906,744.42
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 6,064.00	\$ -	\$ 6,064.00
14	Real-Time Distribution of Losses Amount	\$ (980,115.94)	\$ -	\$ (980,115.94)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (70,807.91)	\$ -	\$ (70,807.91)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (0.73)	\$ -	\$ (0.73)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (63.60)	\$ -	\$ (63.60)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,945,799.48	\$ -	\$ 1,945,799.48
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (10,146.47)	\$ -	\$ (10,146.47)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,563,305.22	\$ -	\$ 1,563,305.22
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 10,146.47	\$ -	\$ 10,146.47
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 75,881.98	\$ -	\$ 75,881.98
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ 64.32	\$ -	\$ 64.32
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,381,013.39)	\$ -	\$ (1,381,013.39)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (100,477.08)	\$ -	\$ (100,477.08)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (293,392.53)	\$ -	\$ (293,392.53)
37	Financial Transmission Guarantee Uplift Amount	\$ 295,869.36	\$ -	\$ 295,869.36
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 776,563.16	\$ -	\$ 776,563.16
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 72,414.94	\$ -	\$ 72,414.94
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (75,184.36)	\$ 450.45	\$ (74,733.91)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 88,823.29	\$ -	\$ 88,823.29
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ 26,552.33	\$ 782.26	\$ 27,334.59
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (204,581.14)	\$ 42,770.37	\$ (161,810.77)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 543,492.38	\$ (9,845.09)	\$ 533,647.29
19	Real-Time Market Administration Amount	\$ 46,295.87	\$ (4,135.12)	\$ 42,160.75
29	Financial Transmission Rights Market Administration Amount	\$ 19,141.60	\$ -	\$ 19,141.60
33	Day-Ahead Schedule 24 Allocation Amount	\$ 82,305.92	\$ (1,497.10)	\$ 80,808.82
34	Real-Time Schedule 24 Allocation Amount	\$ (95,092.03)	\$ 87,727.71	\$ (7,364.32)
35	Schedule 24 Admin Allocation	\$ -	\$ -	\$ -
<b>Virtual Energy Charges</b>				
12	Day-Ahead Virtual Energy Amount	\$ -	\$ -	\$ -
27	Real-Time Virtual Energy Amount	\$ -	\$ -	\$ -
<b>Other MISO Charges</b>				
20	Real-Time Miscellaneous Amount	\$ 13,749.29	\$ 12,121.76	\$ 25,871.05
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,850,841.75	\$ -	\$ 2,850,841.75
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,859,231.18)	\$ -	\$ (2,859,231.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (406,713.43)	\$ -	\$ (406,713.43)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 101,942.72	\$ -	\$ 101,942.72
<b>TOTAL MISO CHARGES</b>		<b>\$ 3,838,907.54</b>	<b>\$ 3,287,893.53</b>	<b>\$ 7,126,801.07</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 73,444.50</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 7,053,356.57</b>

## MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
<b>November 2015 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (30,939.83)	\$ -	\$ (30,939.83)
2	Day-Ahead Spinning Reserve Amount	\$ (126,476.00)	\$ -	\$ (126,476.00)
3	Day-Ahead Supplemental Reserve	\$ (36,215.54)	\$ -	\$ (36,215.54)
4	Real-Time Regulation Amount	\$ (178.88)	\$ 5,298.12	\$ 5,119.24
5	Real-Time Spinning Reserve Amount	\$ (3,161.73)	\$ 77,841.57	\$ 74,679.84
6	Real-Time Supplemental Reserve Amount.	\$ 1,220.60	\$ 1,898.26	\$ 3,118.86
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ 101.44	\$ -	\$ 101.44
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 3,944,156.53	\$ -	\$ 3,944,156.53
8b	Real Time Non Excessive Energy Congestion	\$ (157,392.19)	\$ -	\$ (157,392.19)
8c	Real Time Non Excessive Energy Loss	\$ (60,460.26)	\$ -	\$ (60,460.26)
9	Real Time Net Regulation Adjustment Amount	\$ (582.74)	\$ (333.92)	\$ (916.66)
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 58,269.73	\$ -	\$ 58,269.73
11	Real Time Spinning Reserve Cost Distribution	\$ 76,333.57	\$ -	\$ 76,333.57
12	Real Time Supplemental Reserve Cost Distribution	\$ 43,379.27	\$ -	\$ 43,379.27
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 14,179.43	\$ (1,420.68)	\$ 12,758.75
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 3,722,233.40</b>	<b>\$ 83,283.35</b>	<b>\$ 3,805,516.75</b>

Northern States Power Company  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Asset Based Margin Sharing

1 Forecast Month	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16
2 True-up Month	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
3												
4 Monthly Refund	(58,150)	(58,410)	(63,921)	(11,298)	(31,343)	(34,586)	(41,850)	(56,080)	(64,244)	(66,982)	(22,819)	
5												
6 Forecast North Dakota Sales	214,698	190,045	163,417	175,362	193,801	189,560	181,682	174,056	163,609	218,447	229,474	212,098
7												
8 <b>Current Month Refund Factor</b>	(0.027)	(0.031)	(0.039)	(0.006)	(0.016)	(0.018)	(0.023)	(0.032)	(0.039)	(0.031)	(0.010)	-
9												
14 Expected Refund	(240,764)	87,087	(225,701)	104,158	(229,020)	145,774	(208,331)	181,481	(225,260)	148,015	(288,648)	124,522
15 Actual Refunded	(73,213)	(75,480)	(60,602)	(52,914)	(52,032)	(70,293)	(24,921)	(22,614)	(856)	(43,489)	(42,169)	
16 Deviation	(167,551)	162,567	(165,099)	157,072	(176,988)	216,067	(183,410)	204,095	(224,404)	191,504	(246,479)	124,522
17												
18 <b>True-up Factor</b>	(0.078)	0.086	(0.101)	0.090	(0.091)	0.114	(0.101)	0.117	(0.157)	0.088	(0.107)	-
19												
20 <b>Realized Margin</b>	(0.105)	0.055	(0.140)	0.083	(0.107)	0.096	(0.124)	0.085	(0.176)	0.057	(0.117)	-
21												
22 <b>Class Ratios</b>												
23 Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.105)	0.055	(0.140)	0.083	(0.107)	0.095	(0.124)	0.085	(0.176)	0.057	(0.117)	-
32 C&I Non-Demand	(0.108)	0.057	(0.145)	0.086	(0.111)	0.099	(0.128)	0.088	(0.182)	0.059	(0.121)	-
33 C&I Demand Non-TOD	(0.107)	0.056	(0.143)	0.085	(0.109)	0.098	(0.126)	0.087	(0.180)	0.058	(0.120)	-
34 C&I Demand TOD On-Peak	(0.135)	0.070	(0.179)	0.106	(0.138)	0.123	(0.159)	0.109	(0.226)	0.073	(0.150)	-
35 C&I Demand TOD Off-Peak	(0.084)	0.044	(0.111)	0.066	(0.086)	0.076	(0.099)	0.068	(0.140)	0.045	(0.093)	-
36 Outdoor Lighting	(0.077)	0.040	(0.103)	0.061	(0.079)	0.070	(0.091)	0.062	(0.130)	0.042	(0.086)	-

Northern States Power Company  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Non-Asset Based Margin Sharing

1 Forecast Month	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16
2 True-up Month	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15
3												
4 Monthly Refund	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)
5												
6 Forecast North Dakota Sales	203,682	214,698	190,045	163,417	175,362	193,801	189,560	181,682	174,056	163,609	218,447	229,474
7												
8 <b>Current Month Refund Factor</b>	(0.008)	(0.008)	(0.009)	(0.010)	(0.009)	(0.008)	(0.009)	(0.009)	(0.009)	(0.010)	(0.007)	(0.007)
9												
14 Expected Refund	(9,871)	(6,219)	(16,187)	(13,100)	(22,770)	(13,615)	(23,562)	(14,351)	(21,167)	(10,758)	(19,758)	(10,647)
15 Actual Refund	(9,863)	(9,298)	(9,596)	(15,664)	(15,387)	(15,443)	(18,574)	(19,772)	(17,588)	(16,290)	(14,669)	(14,050)
16 Deviation	(8)	3,079	(6,591)	2,564	(7,383)	1,828	(4,988)	5,421	(3,579)	5,532	(5,089)	3,403
17												
18 <b>True-up Factor</b>	(0.000)	0.001	(0.003)	0.002	(0.004)	0.001	(0.003)	0.003	(0.002)	0.003	(0.002)	0.001
19												
20 <b>Realized Margin</b>	(0.008)	(0.006)	(0.012)	(0.008)	(0.013)	(0.007)	(0.011)	(0.006)	(0.011)	(0.007)	(0.010)	<b>(0.006)</b>
21												
22 <b>Class Ratios</b>												
23 Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.008)	(0.006)	(0.012)	(0.008)	(0.013)	(0.007)	(0.011)	(0.006)	(0.011)	(0.006)	(0.010)	(0.006)
32 C&I Non-Demand	(0.008)	(0.006)	(0.012)	(0.009)	(0.014)	(0.008)	(0.012)	(0.006)	(0.012)	(0.007)	(0.010)	(0.006)
33 C&I Demand Non-TOD	(0.008)	(0.006)	(0.012)	(0.008)	(0.014)	(0.008)	(0.011)	(0.006)	(0.012)	(0.007)	(0.010)	(0.006)
34 C&I Demand TOD On-Peak	(0.010)	(0.008)	(0.015)	(0.011)	(0.017)	(0.009)	(0.014)	(0.008)	(0.015)	(0.008)	(0.012)	(0.007)
35 C&I Demand TOD Off-Peak	(0.006)	(0.005)	(0.010)	(0.007)	(0.011)	(0.006)	(0.009)	(0.005)	(0.009)	(0.005)	(0.008)	(0.004)
36 Outdoor Lighting	(0.006)	(0.004)	(0.009)	(0.006)	(0.010)	(0.005)	(0.008)	(0.004)	(0.008)	(0.005)	(0.007)	(0.004)

Northern States Power Company  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Sales of Renewable Energy Credits

1 Forecast Month	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16
2 True-up Month	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
3												
4 Monthly Refund	-	-	-	-	-	-	-	-	(79,589)	-	-	-
5												
6 Forecast North Dakota Sales	214,698	190,045	163,417	175,362	193,801	189,560	181,682	174,056	163,609	218,447	229,474	
7												
8 <b>Current Month Refund Factor</b>	-	-	-	-	-	-	-	-	(0.049)	-	-	-
9												
14 Expected Refund	(378,673)	240,848	(401,239)	314,753	(346,179)	351,946	(335,018)	398,064	(357,607)	384,436	(495,284)	-
15 Actual Refund	22,566	(73,905)	(55,060)	(37,193)	(11,161)	(46,118)	22,589	13,628	58,089	(1,535)	(7,643)	-
16 Deviation	(401,239)	314,753	(346,179)	351,946	(335,018)	398,064	(357,607)	384,436	(415,696)	385,971	(487,641)	-
17												
18 <b>True-up Factor</b>	(0.187)	0.166	(0.212)	0.201	(0.173)	0.210	(0.197)	0.221	(0.254)	0.177	(0.213)	-
19												
20 <b>Realized Refund</b>	(0.187)	0.166	(0.212)	0.201	(0.173)	0.210	(0.197)	0.221	(0.303)	0.177	(0.213)	-
21												
22 <b>Class Ratios</b>												
23 Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.186)	0.165	(0.211)	0.200	(0.172)	0.209	(0.196)	0.220	(0.302)	0.176	(0.212)	-
32 C&I Non-Demand	(0.193)	0.171	(0.219)	0.207	(0.178)	0.217	(0.203)	0.228	(0.312)	0.182	(0.219)	-
33 C&I Demand Non-TOD	(0.190)	0.169	(0.216)	0.204	(0.176)	0.214	(0.200)	0.225	(0.308)	0.180	(0.216)	-
34 C&I Demand TOD On-Peak	(0.239)	0.212	(0.271)	0.257	(0.221)	0.269	(0.252)	0.283	(0.387)	0.226	(0.272)	-
35 C&I Demand TOD Off-Peak	(0.149)	0.132	(0.168)	0.160	(0.137)	0.167	(0.157)	0.176	(0.241)	0.141	(0.169)	-
36 Outdoor Lighting	(0.137)	0.122	(0.156)	0.147	(0.127)	0.154	(0.144)	0.162	(0.222)	0.130	(0.156)	-