



414 Nicollet Mall  
Minneapolis, Minnesota 55401

— Via Electronic Filing —

July 29, 2016

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

**Re: August 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 August 2016.

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

August 2016	Fuel Cost Charge (\$/kWh)
Residential	0.02394
C & I Non-Demand	0.02478
C & I Demand	0.02446
C & I Demand Time of Day On-Peak	0.03073
C & I Demand Time of Day Off-Peak	0.01910
Outdoor Lighting	0.01763

## **MISO CHARGES IMPLEMENTATION**

### MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO) 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 three Auction Revenue Rights (ARR) and three Financial Transmission Rights (FTR) charge types.<sup>1</sup> Consistent with this Order and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the August 2016 FCC the net MISO Day 2 costs for June 2016 as recorded in Account 555. The MISO Day 2 cost recovery included in this August 2016 FCC is \$6,005,249, 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 August 2016 FCC the net MISO ASM costs for June 2016 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is \$2,614,958, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

## **REFUNDS AND TRUE UP OF PRIOR RECOVERY**

Attachment 3, page 1 contains a summary of prior recovery true up and the following refunds:

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

Under the terms of the Revised Second Amended Settlement adopted by the Commission<sup>2</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 credit of \$11,125 has been included as a credit to the August 2016 Fuel Cost Charges. 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

---

<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

North Dakota retail share of the 2015 Non-Asset Based Margin credit is \$50,462 and this amount has been fully credited to customers.

### 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 RECs is credited to customers. There were no REC sales during the current reporting period.

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

For the August 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.

### **NEGOTIATED AGREEMENT**

Pursuant to the Commission's March 9, 2016 Order Accepting Settlement (Case Nos. PU-12-813, *et. al.*) the costs and volumes of fifteen Community-Based Energy Development (C-BED) and two small solar PPAs are to be excluded from the calculation of the Company's monthly FCR charge. This monthly report reflects the adjustments addressed in the Commission's Order. Please see Attachment 1, Page 5 for the details.

The excluded C-BED and solar PPAs are as follows:

**Community Based Energy Development (CBED) Wind**

1. Jeffers Wind 20, LLC (50 MW)
2. Big Blue (36 MW)
3. Community Wind South (Zephyr) (30 MW)
4. Ridgewind Power Partners LLC (25 MW)
5. Adams Wind Generations (20 MW)
6. Danielson Wind Farms (20 MW)
7. Ewington Energy Systems LLC (20 MW)
8. Grant County Wind, LLC (20 MW)
9. North Community Turbines (15 MW)
10. North Wind Turbines (15 MW)
11. Valley View Transmission (10 MW)
12. Uilk Wind Farm (4.5 MW)
13. Hilltop Power (2 MW)
14. Winona County Wind (1.5 MW)
15. Woodstock Municipal Wind, LLC (0.8 MW)

**Solar Contracts**

1. Outland Solar (2 MW)
2. Best Power (St. Johns) (0.4 MW)

**MONTHLY CALCULATIONS AND COMPARISONS**

Attached is the calculation of the August 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  
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 Aug-2016

Aug-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Base & FCA Factor
<b>System</b>	<b>\$0.02258</b>	<b>\$0.00143</b>	<b>\$0.02401</b>
<b>Residential</b>	<b>\$0.02251</b>	<b>\$0.00143</b>	<b>\$0.02394</b>
<b>C &amp; I Non-Demand</b>	<b>\$0.02330</b>	<b>\$0.00148</b>	<b>\$0.02478</b>
<b>C &amp; I Demand Non-TOD</b>	<b>\$0.02300</b>	<b>\$0.00146</b>	<b>\$0.02446</b>
<b>C &amp; I Demand TOD On-Peak</b>	<b>\$0.02890</b>	<b>\$0.00183</b>	<b>\$0.03073</b>
<b>C &amp; I Demand TOD Off-Peak</b>	<b>\$0.01796</b>	<b>\$0.00114</b>	<b>\$0.01910</b>
<b>Outdoor Lighting</b>	<b>\$0.01658</b>	<b>\$0.00105</b>	<b>\$0.01763</b>
<b>Residential</b>			
Residential Service	\$ 0.02251	\$ 0.00143	\$ 0.02394
Residential TOD	\$ 0.02251	\$ 0.00143	\$ 0.02394
Residential - Underground	\$ 0.02251	\$ 0.00143	\$ 0.02394
Residential TOD - Underground	\$ 0.02251	\$ 0.00143	\$ 0.02394
Energy Control - (Non-Demand)	\$ 0.02251	\$ 0.00143	\$ 0.02394
Limit Off Peak	\$ 0.02251	\$ 0.00143	\$ 0.02394
<b>C &amp; I Non-Demand</b>			
Energy Controlled - (Non-Demand)	\$ 0.02330	\$ 0.00148	\$ 0.02478
Limit Off Peak	\$ 0.02330	\$ 0.00148	\$ 0.02478
Small General Service	\$ 0.02330	\$ 0.00148	\$ 0.02478
Small General TOD - Metered	\$ 0.02330	\$ 0.00148	\$ 0.02478
Small General TOD - Unmetered	\$ 0.02330	\$ 0.00148	\$ 0.02478
Fire and Civil Defense Siren	\$ 0.02330	\$ 0.00148	\$ 0.02478
Direct Current (Closed)	\$ 0.02330	\$ 0.00148	\$ 0.02478
<b>C &amp; I Demand</b>			
General Service	\$ 0.02300	\$ 0.00146	\$ 0.02446
General TOD - On Peak	\$ 0.02890	\$ 0.00183	\$ 0.03073
General TOD - Off Peak	\$ 0.01796	\$ 0.00114	\$ 0.01910
Peak Controlled (Closed)	\$ 0.02300	\$ 0.00146	\$ 0.02446
Peak Controlled TOD (Closed) - On Peak	\$ 0.02890	\$ 0.00183	\$ 0.03073
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01796	\$ 0.00114	\$ 0.01910
Peak Controlled Tiered	\$ 0.02300	\$ 0.00146	\$ 0.02446
Peak Controlled Tiered TOD - On Peak	\$ 0.02890	\$ 0.00183	\$ 0.03073
Peak Controlled Tiered TOD - Off Peak	\$ 0.01796	\$ 0.00114	\$ 0.01910
Energy Controlled (Closed)	\$ 0.02300	\$ 0.00146	\$ 0.02446
Tier 1 Energy Controlled Rider	\$ 0.02300	\$ 0.00146	\$ 0.02446
Real Time Pricing - Firm - On Peak	\$ 0.02890	\$ 0.00183	\$ 0.03073
Real Time Pricing - Firm - Off Peak	\$ 0.01796	\$ 0.00114	\$ 0.01910
Real Time Pricing - Controllable - On Peak	\$ 0.02890	\$ 0.00183	\$ 0.03073
Real Time Pricing - Controllable - Off Peak	\$ 0.01796	\$ 0.00114	\$ 0.01910
Small Municipal Pumping	\$ 0.02300	\$ 0.00146	\$ 0.02446
Municipal Pumping	\$ 0.02300	\$ 0.00146	\$ 0.02446
Excess Energy - St. Anthony Falls	\$ 0.02300	\$ 0.00146	\$ 0.02446
<b>Outdoor Lighting</b>			
Automatic Protective Lighting	\$ 0.01658	\$ 0.00105	\$ 0.01763
Street Lighting System	\$ 0.01658	\$ 0.00105	\$ 0.01763
Street Lighting Energy	\$ 0.01658	\$ 0.00105	\$ 0.01763
Street Lighting Energy - Metered	\$ 0.01658	\$ 0.00105	\$ 0.01763
Street Lighting Energy (Closed)	\$ 0.01658	\$ 0.00105	\$ 0.01763
Street Lighting - City of St. Paul	\$ 0.01658	\$ 0.00105	\$ 0.01763

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

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Mar-16	Apr-16	May-16	Jun-16	4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$27,324,375	\$23,358,395	\$26,821,520	\$34,691,290	\$112,195,580
Account 518 - Nuclear Fuel	\$10,696,586	\$10,504,918	\$10,864,217	\$10,468,675	\$42,534,396
Account 555 - Purchased Power <sup>1</sup>	\$38,591,082	\$42,633,423	\$37,639,621	\$35,952,045	\$154,816,171
C-BED Wind & Solar PPA Costs	(\$4,778,197)	(\$5,632,183)	(\$3,826,145)	(\$3,598,502)	(\$17,835,026)
C-BED Wind PPA Curtailment Payment	(\$221,503)	(\$203,950)	(\$175,684)	(\$138,118)	(\$739,255)
Replacement Energy Costs	\$2,038,451	\$2,275,487	\$1,455,875	\$1,391,290	\$7,161,103
Account 555 - With PPAs Adjustment <sup>2</sup>	(\$2,961,249)	(\$3,560,646)	(\$2,545,953)	(\$2,345,330)	(\$11,413,178)
MISO Day 2 Charges	\$4,691,629	\$1,644,428	\$1,245,289	\$6,076,958	\$13,658,305
MISO Day 2 - Schedule 24	(\$82,385)	(\$87,127)	(\$95,620)	(\$71,709)	(\$336,840)
MISO - ASM Charges	\$797,506	\$1,860,918	\$1,857,686	\$2,614,958	\$7,131,068
Account 555 - Total MISO Charges	\$5,406,751	\$3,418,219	\$3,007,355	\$8,620,207	\$20,452,532
Financial Instruments	\$0	\$0	\$0	\$0	\$0
<b>Total System Costs</b>	<b>\$79,057,544</b>	<b>\$76,354,309</b>	<b>\$75,786,760</b>	<b>\$87,386,887</b>	<b>\$318,585,501</b>
Less Fuel Cost of InterSystem Sales	(\$6,558,736)	(\$9,933,338)	(\$4,502,564)	(\$4,709,292)	(\$25,703,930)
<b>Net System Costs</b>	<b>\$72,498,808</b>	<b>\$66,420,971</b>	<b>\$71,284,196</b>	<b>\$82,677,596</b>	<b>\$292,881,571</b>
<b>System MWh Sales</b>					
Total NSP System Retail	3,486,859	2,932,612	3,094,585	3,454,370	12,968,426
Non-Gen Muni's/Load Pattern	-	-	-	-	-
<b>Total NSP System MWh Sales</b>	<b>3,486,859</b>	<b>2,932,612</b>	<b>3,094,585</b>	<b>3,454,370</b>	<b>12,968,426</b>
<b>Average Unit Cost of Fuel and Purchased Power</b>					
<b>Fuel Cost per kWh for NSP System</b>					
System (Including All PPAs)	2.164¢	2.386¢	2.386¢	2.461¢	2.346¢
System (Adjusted for 17 PPAs Exclusion)	2.079¢	2.265¢	2.304¢	2.393¢	2.258¢
<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			2.258¢	0.9969	2.251¢
(ii) C & I Non-Demand			2.258¢	1.0318	2.330¢
(iii) C & I Demand Non-TOD			2.258¢	1.0184	2.300¢
(iv) C & I Demand TOD On-Peak			2.258¢	1.2798	2.890¢
(v) C & I Demand TOD Off-Peak			2.258¢	0.7954	1.796¢
(vi) Outdoor Lighting			2.258¢	0.7341	1.658¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	73,616	56,587	47,829	52,879	230,911
(ii) C & I Non-Demand	11,328	8,714	7,835	8,039	35,916
(iii) C & I Demand Non-TOD	73,347	55,348	61,128	62,771	252,594
(iv) C & I Demand TOD On-Peak	18,502	14,566	19,206	19,558	71,832
(v) C & I Demand TOD Off-Peak	28,824	23,540	29,090	31,752	113,206
(vi) Outdoor Lighting	1,703	1,497	1,257	1,143	5,600
(vii) Total	207,320	160,252	166,345	176,142	710,059
<b>Aug-2016 Recovery Provision (True-up Factor) Calculation</b>					
<b>Prior Unrecovered Expenses (Apr-16 Balance of Unrecovered Expenses)</b>					<b>Total</b>
					<b>Apr-16</b>
					<b>(\$599,996)</b>

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

<sup>2</sup> Excludes 17 PPAs pursuant to March 9, 2016 Order Approving Settlement

Prior Expenses Recovered in Jun-2016 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	52,879	(\$87,716)
(ii) C & I Non-Demand	8,039	(\$14,123)
(iii) C & I Demand Non-TOD	62,771	(\$107,078)
(iv) C & I Demand TOD On-Peak	19,558	(\$41,931)
(v) C & I Demand TOD Off-Peak	31,752	(\$41,977)
(vi) Outdoor Lighting	1,143	(\$1,684)
(vii) Total	176,142	(\$294,509)

Actual Cost Should Have Been Recovered in Jun-16				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.393¢	0.000¢	176,142	\$4,215,078

Cost Recovered in Jun-16 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	52,879	\$861,671
(ii) C & I Non-Demand	8,039	\$138,077
(iii) C & I Demand Non-TOD	62,771	\$1,059,361
(iv) C & I Demand TOD On-Peak	19,558	\$451,132
(v) C & I Demand TOD Off-Peak	31,752	\$369,976
(vi) Outdoor Lighting	1,143	\$11,650
(vii) Total	176,142	\$2,891,867

Total Balance of Unrecovered Expenses (Aug-16 Balance of Unrecovered Expenses)	
Aug-2016 Recovery Provision	\$1,017,724
4 Month ND Retail Total MWh Sales	710,059
<b>Aug-2016 Recovery Provision per KWH</b>	<b>0.143¢</b>

Aug-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	0.143¢	0.143¢
(ii) C & I Non-Demand	1.0318	0.143¢	0.148¢
(iii) C & I Demand Non-TOD	1.0184	0.143¢	0.146¢
(iv) C & I Demand TOD On-Peak	1.2798	0.143¢	0.183¢
(v) C & I Demand TOD Off-Peak	0.7954	0.143¢	0.114¢
(vi) Outdoor Lighting	0.7341	0.143¢	0.105¢

Aug-2016 Factors	
	Total
(i) Residential	2.394¢
(ii) C & I Non-Demand	2.478¢
(iii) C & I Demand Non-TOD	2.446¢
(iv) C & I Demand TOD On-Peak	3.073¢
(v) C & I Demand TOD Off-Peak	1.910¢
(vi) Outdoor Lighting	1.763¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jul-16	Aug-16	Difference	Percent Change	FCA Application Jul-16	Aug-16	Difference
** COSTS (Millions) **							
1 Fossil	\$112.2	\$112.2	(\$0.0)	0.0%	35.2%	35.2%	0.0%
2 Nuclear	\$39.3	\$42.5	\$3.2	8.1%	12.3%	13.4%	1.1%
3 Purchases	\$147.9	\$143.4	(\$4.5)	-3.0%	46.4%	45.0%	-1.4%
MISO related Purchases	\$19.2	\$20.5	\$1.2	6.5%	6.0%	6.4%	0.4%
4 Total System Costs	318.7	318.6	(\$0.1)	0.0%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$27.2	\$25.7	(\$1.5)	-5.4%	8.5%	8.1%	-0.4%
6 Net System Costs	\$291.5	\$292.9	\$1.4	0.5%	91.5%	91.9%	0.4%
7							
8 ** GWH OUTPUT **							
9 Fossil	3,092	3,104	12	0.4%	33.9%	32.0%	-1.9%
10 Nuclear	4,733	5,039	306	6.5%	51.9%	52.0%	0.1%
11 Purchases	3,886	3,879	(7)	-0.2%	42.6%	40.1%	-2.5%
12 Hydro & Other	3,309	3,329	20	0.6%	36.3%	34.4%	-1.9%
13 Net Interchange	(5,897)	(5,666)	231	3.9%	-64.6%	-58.5%	6.1%
14 Total Output	9,123	9,685	562	6.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,804	1,559	(245)	-13.6%	19.8%	16.1%	-3.7%
16 Native Requirement	7,319	8,126	807	11.0%	80.2%	83.9%	3.7%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.630	3.615	-0.015	-0.4%			
20 Nuclear	0.831	0.844	0.013	1.5%			
21 Purchases	3.806	3.697	-0.109	-2.9%			
22 Total System Costs	3.493	3.289	-0.204	-5.8%			
23 Intersystem Sales	1.506	1.649	0.143	9.5%			
24 Net System Costs	3.983	3.604	-0.379	-9.5%			
25							
26							
27 TOTAL SYSTEM GWH SALES	12,891	12,968	77	0.6%			
28							
29 COST per KWH SALES (¢)	2.261	2.258	-0.003	-0.1%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.426	0.143	0.569				
(i) Residential	-0.425	0.143	0.568				
(ii) C & I Non-Demand	-0.440	0.148	0.588				
(iii) C & I Demand Non-TOD	-0.434	0.146	0.580				
(iv) C & I Demand TOD On-Peak	-0.545	0.183	0.729				
(v) C & I Demand TOD Off-Peak	-0.339	0.114	0.453				
(vi) Outdoor Lighting	-0.313	0.105	0.418				
32 REFUND	0.000	0.000	0.000				
(i) Residential	0.000	0.000					
(ii) C & I Non-Demand	0.000	0.000					
(iii) C & I Demand Non-TOD	0.000	0.000					
(iv) C & I Demand TOD On-Peak	0.000	0.000					
(v) C & I Demand TOD Off-Peak	0.000	0.000					
(vi) Outdoor Lighting	0.000	0.000					
33 SYSTEM FCC IMPACT (¢ / KWH)	1.835	2.401	0.566	30.9%			
(i) Residential	1.829	2.394	0.565				
(ii) C & I Non-Demand	1.893	2.478					
(iii) C & I Demand Non-TOD	1.869	2.446					
(iv) C & I Demand TOD On-Peak	2.348	3.073					
(v) C & I Demand TOD Off-Peak	1.459	1.910					
(vi) Outdoor Lighting	1.347	1.763					

Residential BILL IMPACT (\$'s)

Calculations:

		Change from kWh Previous Month
[ 4 ] = [1]+[2]+[3]	[21] = [3] / [11]	
[ 6 ] = [4] - [5]	[22] = [4] / [14]	100
[14] = [9]+..+[13]	[23] = [5] / [15]	250
[16] = [14] - [15]	[24] = [6] / [16]	500
[19] = [1] / [9]	[29] = [6] / [27]	750
[20] = [2] / [10]	[33] = [29]+[31]	1,000
		\$0.56
		\$1.41
		\$2.82
		\$4.24
		\$5.65

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>	
	Jul-16	Aug-16
<b>** GWH OUTPUT **</b>		
Thermal	2,185,668	2,174,167
Disper gen	(46)	(59)
<u>Hydro plus Wind</u>	1,123,627	1,155,138
Hydro and Other	3,309,249	3,329,246
Rounded to nearest thousand:	3,309	3,329
<u>Sales</u>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale &amp; Interchange (Intersystem)</u>	1,803,830,000	1,558,550,000
Rounded to nearest million:	1803.83	1558.55

**Northern States Power Company**  
**Electric Operations - State of North Dakota**

Derivation of Replacement Cost for the Designated Purchased Power Agreements  
 For Actual Month of June 2016 (August FCC)

	PPAs Included	PPAs Excluded	Difference	Adjustment to ND Fuel Cost
<b>PPAs Replacement Cost</b>				
System Fuel Costs	\$85,022,926	\$85,022,926		
Less: PPAs Exclusion				
15 C-BED Wind PPAs	\$0	(\$3,552,894)		
2 Solar PPAs	\$0	(\$45,608)		
Wind Curtailment Payments	\$0	(\$138,118)		
Total Exclusion	<u>\$0</u>	<u>(\$3,736,620)</u>		
Net System Costs	\$85,022,926	\$81,286,306		
Billing Month System Sales	3454370	3454370		
Billing Month North Dakota Sales	176142	176142		
North Dakota Percentage	5.0991%	5.0991%		
Affected PPAs Volume (System)	58140	58140		
Affected PPAs Volume (North Dakota's Share)	2965	2965		
Billing Month System Sales	3454370	3454370		
Less: Affected PPAs Volume		<u>-58140</u>		
Net System Billing Month Sales	<u>3454370</u>	<u>3396230</u>		
Billing Month North Dakota Sales	176142	176142		
Less: Affected PPAs Volume		<u>-2965</u>		
Net North Dakota Billing Month Sales	<u>176142</u>	<u>173177</u>		
System Fuel Costs	\$85,022,926	\$81,286,306		
North Dakota Percentage	5.0991%	5.0991%		
North Dakota Fuel Cost	\$4,335,404	\$4,144,870	(\$190,534)	
Affected PPAs Volume (System)		58140		
North Dakota Average System Cost (\$/MWh)		\$23.93		
North Dakota Replacement Cost	\$0	\$1,391,539		
Affected PPAs Volume (North Dakota's Share)		2965		
North Dakota Average System Cost (\$/MWh)		\$23.93		
North Dakota Replacement Cost	\$0	\$70,965	\$70,965	
Adjusted PPA Cost Added to ND FCA Calculation				(\$119,569)
Fuel Cost Impact Due to PPA Exclusion				(\$0.00069)
Residential Fuel Cost Charge Impact (750 kWh Use)				(\$0.52)

		System	Intersystem	Retail
June 2016 Actual				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 7,039,423.55	\$ 1,624,553.46	\$ 8,663,977.01
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,028,160.69	\$ -	\$ 2,028,160.69
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ (2,221.02)	\$ -	\$ (2,221.02)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,479,565.97)	\$ -	\$ (10,479,565.97)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,250,965.17	\$ -	\$ 1,250,965.17
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ 2,221.01	\$ -	\$ 2,221.01
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 2,613,263.40	\$ 799,485.93	\$ 3,412,749.33
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (23,100.88)	\$ -	\$ (23,100.88)
14	Real-Time Distribution of Losses Amount	\$ (177,928.43)	\$ -	\$ (177,928.43)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ 6.01	\$ -	\$ 6.01
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ (6.01)	\$ -	\$ (6.01)
21	Real-time Net inadvertent Distribution	\$ 730,335.15	\$ -	\$ 730,335.15
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 244,045.95	\$ -	\$ 244,045.95
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (19,319.27)	\$ -	\$ (19,319.27)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 30,704.84	\$ -	\$ 30,704.84
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (10,697.44)	\$ -	\$ (10,697.44)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,869,136.85	\$ -	\$ 1,869,136.85
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 10,697.44	\$ -	\$ 10,697.44
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ (154,385.45)	\$ -	\$ (154,385.45)
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ 32.60	\$ -	\$ 32.60
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (32.60)	\$ -	\$ (32.60)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (36,181.84)	\$ -	\$ (36,181.84)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,404,238.41)	\$ -	\$ (1,404,238.41)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (181,031.43)	\$ -	\$ (181,031.43)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 82,809.64	\$ -	\$ 82,809.64
37	Financial Transmission Guarantee Uplift Amount	\$ (85,118.38)	\$ -	\$ (85,118.38)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (666,842.61)	\$ -	\$ (666,842.61)
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 105,773.16	\$ -	\$ 105,773.16
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (42,116.71)	\$ 4,792.22	\$ (37,324.49)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 384,950.52	\$ -	\$ 384,950.52
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (126,207.94)	\$ 51,099.69	\$ (75,108.25)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (216,213.25)	\$ 17,664.67	\$ (198,548.58)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 579,962.07	\$ (4,137.04)	\$ 575,825.03
19	Real-Time Market Administration Amount	\$ 48,947.38	\$ (2,782.57)	\$ 46,164.81
29	Financial Transmission Rights Market Administration Amount	\$ 35,475.36	\$ -	\$ 35,475.36
33	Day-Ahead Schedule 24 Allocation Amount	\$ 90,636.45	\$ (779.95)	\$ 89,856.50
34	Real-Time Schedule 24 Allocation Amount	\$ (121,228.20)	\$ 103,081.02	\$ (18,147.18)
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	\$ 2,271.42	\$ 54,339.70	\$ 56,611.12
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,398,660.25	\$ -	\$ 2,398,660.25
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,416,523.31)	\$ 44,288.40	\$ (2,372,234.91)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (78,450.07)	\$ -	\$ (78,450.07)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 78,282.87	\$ -	\$ 78,282.87
<b>TOTAL MISO CHARGES</b>		<b>\$ 3,385,352.56</b>	<b>\$ 2,691,605.53</b>	<b>\$ 6,076,958.09</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 71,709.32</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 6,005,248.77</b>

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

		System	Intersystem	Retail
<b>June 2016 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (112,914.37)		\$ (112,914.37)
2	Day-Ahead Spinning Reserve Amount	\$ (86,733.37)		\$ (86,733.37)
3	Day-Ahead Supplemental Reserve	\$ (43,329.56)		\$ (43,329.56)
4	Real-Time Regulation Amount	\$ (61,187.64)	\$ 93,216.07	\$ 32,028.43
5	Real-Time Spinning Reserve Amount	\$ 29,078.93	\$ 17,696.44	\$ 46,775.37
6	Real-Time Supplemental Reserve Amount.	\$ 26,699.14	\$ 1,090.63	\$ 27,789.77
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ 15,895.07		\$ 15,895.07
7b	Real Time Excessive Energy Congestion			\$ -
7c	Real Time Excessive Energy Loss			\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,888,043.33		\$ 1,888,043.33
8b	Real Time Non Excessive Energy Congestion	\$ 318,919.27		\$ 318,919.27
8c	Real Time Non Excessive Energy Loss	\$ 172,045.36		\$ 172,045.36
9	Real Time Net Regulation Adjustment Amount	\$ 25,272.22	\$ (5,925.28)	\$ 19,346.94
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 72,929.08		\$ 72,929.08
11	Real Time Spinning Reserve Cost Distribution	\$ 143,210.28		\$ 143,210.28
12	Real Time Supplemental Reserve Cost Distribution	\$ 31,102.86		\$ 31,102.86
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 108,584.23	\$ (23,354.89)	\$ 85,229.34
14	Real Time Contignecy Reserve Deployment Failure	\$ 5,029.43	\$ (408.74)	\$ 4,620.69
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 2,532,644.26</b>	<b>\$ 82,314.23</b>	<b>\$ 2,614,958.49</b>

Summary of Refund Adjustment Included in Fuel Clause for August 2016 Fuel Cost Charge

North Dakota True-up Detail for August 2016 FCC					
	Fuel Recovery True Up	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Sharing Refund	Total
April Unrecovered Expenses	(\$599,996)				(\$599,996)
Less: April Recovery of March Unrecovered	\$294,509				\$294,509
Actual June Recovery	(\$2,891,867)				(\$2,891,867)
Less: Expected June Recovery	\$4,215,078				\$4,215,078
Less: Asset Based Margin Sharing		(\$11,125)			(\$11,125)
Less: Non Asset Based Margin Sharing			\$0		\$0
Less: REC Sharing				\$0	\$0
Miscellaneous Adjustment					\$0
Total Under/(Over) Recovered Expenses	\$1,017,724	(\$11,125)	\$0	\$0	\$1,006,599
August Four Month Average MWh Sales	710,059	710,059	710,059	710,059	710,059
True-up Factor per KWH (cents/kWh)	0.143	(0.002)	0.000	0.000	0.142