



414 Nicollet Mall
Minneapolis, Minnesota 55401

— Via Electronic Filing —

June 30, 2016

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

Re: July 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 July 2016.

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

July 2016	Fuel Cost Charge (\$/kWh)
Residential	0.01829
C & I Non-Demand	0.01893
C & I Demand	0.01869
C & I Demand Time of Day On-Peak	0.02348
C & I Demand Time of Day Off-Peak	0.01459
Outdoor Lighting	0.01347

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.¹ Consistent with this Order and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the July 2016 FCC the net MISO Day 2 costs for May 2016 as recorded in Account 555. The MISO Day 2 cost recovery included in this July 2016 FCC is \$1,149,669, 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 July 2016 FCC the net MISO ASM costs for May 2016 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is \$1,857,686, 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, 2014.² 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.

¹ Previously embedded in other FTR charge types.

² 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 Commission³ 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 \$321,749 has been included as a credit to the July 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 North Dakota retail share of the 2015 Non-Asset Based Margin credit is \$50,462 and this credit amount has been fully credited to customers Attachment 3, page 1 contains the summary of the credit and true up amount of these refunds.

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. (See Attachment 3, page 1). 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.

³ 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

For the July 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 t 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. Ulk 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 July 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

Jul-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Base & FCA Factor
System	\$0.02261	-\$0.00426	\$0.01835
Residential	\$0.02254	-\$0.00425	\$0.01829
C & I Non-Demand	\$0.02333	-\$0.00440	\$0.01893
C & I Demand Non-TOD	\$0.02303	-\$0.00434	\$0.01869
C & I Demand TOD On-Peak	\$0.02894	-\$0.00545	\$0.02348
C & I Demand TOD Off-Peak	\$0.01798	-\$0.00339	\$0.01459
Outdoor Lighting	\$0.01660	-\$0.00313	\$0.01347
Residential			
Residential Service	\$ 0.02254	\$ (0.00425)	\$ 0.01829
Residential TOD	\$ 0.02254	\$ (0.00425)	\$ 0.01829
Residential - Underground	\$ 0.02254	\$ (0.00425)	\$ 0.01829
Residential TOD - Underground	\$ 0.02254	\$ (0.00425)	\$ 0.01829
Energy Control - (Non-Demand)	\$ 0.02254	\$ (0.00425)	\$ 0.01829
Limit Off Peak	\$ 0.02254	\$ (0.00425)	\$ 0.01829
C & I Non-Demand			
Energy Controlled - (Non-Demand)	\$ 0.02333	\$ (0.00440)	\$ 0.01893
Limit Off Peak	\$ 0.02333	\$ (0.00440)	\$ 0.01893
Small General Service	\$ 0.02333	\$ (0.00440)	\$ 0.01893
Small General TOD - Metered	\$ 0.02333	\$ (0.00440)	\$ 0.01893
Small General TOD - Unmetered	\$ 0.02333	\$ (0.00440)	\$ 0.01893
Fire and Civil Defense Siren	\$ 0.02333	\$ (0.00440)	\$ 0.01893
Direct Current (Closed)	\$ 0.02333	\$ (0.00440)	\$ 0.01893
C & I Demand			
General Service	\$ 0.02303	\$ (0.00434)	\$ 0.01869
General TOD - On Peak	\$ 0.02894	\$ (0.00545)	\$ 0.02348
General TOD - Off Peak	\$ 0.01798	\$ (0.00339)	\$ 0.01459
Peak Controlled (Closed)	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Peak Controlled TOD (Closed) - On Peak	\$ 0.02894	\$ (0.00545)	\$ 0.02348
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01798	\$ (0.00339)	\$ 0.01459
Peak Controlled Tiered	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Peak Controlled Tiered TOD - On Peak	\$ 0.02894	\$ (0.00545)	\$ 0.02348
Peak Controlled Tiered TOD - Off Peak	\$ 0.01798	\$ (0.00339)	\$ 0.01459
Energy Controlled (Closed)	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Tier 1 Energy Controlled Rider	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Real Time Pricing - Firm - On Peak	\$ 0.02894	\$ (0.00545)	\$ 0.02348
Real Time Pricing - Firm - Off Peak	\$ 0.01798	\$ (0.00339)	\$ 0.01459
Real Time Pricing - Controllable - On Peak	\$ 0.02894	\$ (0.00545)	\$ 0.02348
Real Time Pricing - Controllable - Off Peak	\$ 0.01798	\$ (0.00339)	\$ 0.01459
Small Municipal Pumping	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Municipal Pumping	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Excess Energy - St. Anthony Falls	\$ 0.02303	\$ (0.00434)	\$ 0.01869
Outdoor Lighting			
Automatic Protective Lighting	\$ 0.01660	\$ (0.00313)	\$ 0.01347
Street Lighting System	\$ 0.01660	\$ (0.00313)	\$ 0.01347
Street Lighting Energy	\$ 0.01660	\$ (0.00313)	\$ 0.01347
Street Lighting Energy - Metered	\$ 0.01660	\$ (0.00313)	\$ 0.01347
Street Lighting Energy (Closed)	\$ 0.01660	\$ (0.00313)	\$ 0.01347
Street Lighting - City of St. Paul	\$ 0.01660	\$ (0.00313)	\$ 0.01347

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

	Column (A) Feb-16	Column (B) Mar-16	Column (C) Apr-16	Column (D) May-16	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$34,725,752	\$27,324,375	\$23,358,395	\$26,821,520	\$112,230,042
Account 518 - Nuclear Fuel	\$7,279,561	\$10,696,586	\$10,504,918	\$10,864,217	\$39,345,282
Account 555 - Purchased Power ¹	\$38,089,568	\$38,591,082	\$42,633,423	\$37,639,621	\$156,953,693
C-BED Wind & Solar PPA Costs	\$0	(\$4,778,197)	(\$5,632,183)	(\$3,826,145)	(\$14,236,524)
C-BED Wind PPA Curtailment Payment	\$0	(\$221,503)	(\$203,950)	(\$175,684)	(\$601,137)
Replacement Energy Costs	\$0	\$2,038,451	\$2,275,487	\$1,455,875	\$5,769,813
Account 555 - With PPAs Adjustment ²	\$0	(\$2,961,249)	(\$3,560,646)	(\$2,545,953)	(\$9,067,848)
MISO Day 2 Charges	\$6,341,748	\$4,691,629	\$1,644,428	\$1,245,289	\$13,923,095
MISO Day 2 - Schedule 24	(\$97,706)	(\$82,385)	(\$87,127)	(\$95,620)	(\$362,837)
MISO - ASM Charges	\$1,132,280	\$797,506	\$1,860,918	\$1,857,686	\$5,648,389
Account 555 - Total MISO Charges	\$7,376,322	\$5,406,751	\$3,418,219	\$3,007,355	\$19,208,647
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$87,471,203	\$79,057,544	\$76,354,309	\$75,786,760	\$318,669,816
Less Fuel Cost of InterSystem Sales	(\$6,168,145)	(\$6,558,736)	(\$9,933,338)	(\$4,502,564)	(\$27,162,783)
Net System Costs	\$81,303,058	\$72,498,808	\$66,420,971	\$71,284,196	\$291,507,033
System MWh Sales					
Total NSP System Retail	3,376,930	3,486,859	2,932,612	3,094,585	12,890,986
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	3,376,930	3,486,859	2,932,612	3,094,585	12,890,986
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
System (Including All PPAs)	2.408¢	2.164¢	2.386¢	2.386¢	2.332¢
System (Adjusted for 17 PPAs Exclusion)	2.408¢	2.079¢	2.265¢	2.304¢	2.261¢
Class Ratio/TOD Ratio					
(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
North Dakota Fuel Cost Factor (FCF)					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			2.261¢	0.9969	2.254¢
(ii) C & I Non-Demand			2.261¢	1.0318	2.333¢
(iii) C & I Demand Non-TOD			2.261¢	1.0184	2.303¢
(iv) C & I Demand TOD On-Peak			2.261¢	1.2798	2.894¢
(v) C & I Demand TOD Off-Peak			2.261¢	0.7954	1.798¢
(vi) Outdoor Lighting			2.261¢	0.7341	1.660¢
North Dakota Retail MWh Sales					
(i) Residential	79,199	73,616	56,587	47,829	257,231
(ii) C & I Non-Demand	11,058	11,328	8,714	7,835	38,935
(iii) C & I Demand Non-TOD	64,747	73,347	55,348	61,128	254,570
(iv) C & I Demand TOD On-Peak	17,746	18,502	14,566	19,206	70,020
(v) C & I Demand TOD Off-Peak	28,781	28,824	23,540	29,090	110,235
(vi) Outdoor Lighting	1,956	1,703	1,497	1,257	6,413
(vii) Total	203,487	207,320	160,252	166,345	737,404
Jul-2016 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Mar-16 Balance of Unrecovered Expenses)					Total
					Mar-16
					(\$2,043,823)

¹ Excludes demand-related expenses

² Excludes 17 PPAs pursuant to March 9, 2016 Order Approving Settlement

Prior Expenses Recovered in May-2016 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	47,829	(\$61,425)
(ii) C & I Non-Demand	7,835	(\$9,998)
(iii) C & I Demand Non-TOD	61,128	(\$79,688)
(iv) C & I Demand TOD On-Peak	19,206	(\$31,461)
(v) C & I Demand TOD Off-Peak	29,090	(\$29,326)
(vi) Outdoor Lighting	1,257	(\$804)
(vii) Total	166,345	(\$212,702)

Actual Cost Should Have Been Recovered in May-16				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.304¢	0.000¢	166,345	\$3,832,589

Cost Recovered in May-16 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	47,829	\$1,470,770
(ii) C & I Non-Demand	7,835	\$248,336
(iii) C & I Demand Non-TOD	61,128	\$1,916,487
(iv) C & I Demand TOD On-Peak	19,206	\$726,451
(v) C & I Demand TOD Off-Peak	29,090	\$750,903
(vi) Outdoor Lighting	1,257	\$30,881
(vii) Total	166,345	\$5,143,828

Total Balance of Unrecovered Expenses (Jul-16 Balance of Unrecovered Expenses)	
Jul-2016 Recovery Provision	(\$3,142,360)
4 Month ND Retail Total MWh Sales	737,404
Jul-2016 Recovery Provision per KWH	-0.426¢

Jul-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	-0.426¢	-0.425¢
(ii) C & I Non-Demand	1.0318	-0.426¢	-0.440¢
(iii) C & I Demand Non-TOD	1.0184	-0.426¢	-0.434¢
(iv) C & I Demand TOD On-Peak	1.2798	-0.426¢	-0.545¢
(v) C & I Demand TOD Off-Peak	0.7954	-0.426¢	-0.339¢
(vi) Outdoor Lighting	0.7341	-0.426¢	-0.313¢

Jul-2016 Factors		Total
(i) Residential		1.829¢
(ii) C & I Non-Demand		1.893¢
(iii) C & I Demand Non-TOD		1.869¢
(iv) C & I Demand TOD On-Peak		2.348¢
(v) C & I Demand TOD Off-Peak		1.459¢
(vi) Outdoor Lighting		1.347¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jun-16	Jul-16	Difference	Percent Change	FCA Application Jun-16	Jul-16	Difference
** COSTS (Millions) **							
1 Fossil	\$130.4	\$112.2	(\$18.2)	-14.0%	38.3%	35.2%	-3.1%
2 Nuclear	\$35.6	\$39.3	\$3.8	10.6%	10.4%	12.3%	1.9%
3 Purchases	\$151.0	\$147.9	(\$3.1)	-2.1%	44.3%	46.4%	2.1%
MISO related Purchases	\$23.9	\$19.2	(\$4.7)	-19.8%	7.0%	6.0%	-1.0%
4 Total System Costs	340.9	318.7	(\$22.3)	-6.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$30.0	\$27.2	(\$2.8)	-9.4%	8.8%	8.5%	-0.3%
6 Net System Costs	\$311.0	\$291.5	(\$19.4)	-6.3%	91.2%	91.5%	0.3%
7							
8 ** GWH OUTPUT **							
9 Fossil	3,730	3,092	(638)	-17.1%	39.2%	33.9%	-5.3%
10 Nuclear	4,344	4,733	389	9.0%	45.6%	51.9%	6.3%
11 Purchases	3,822	3,886	64	1.7%	40.1%	42.6%	2.5%
12 Hydro & Other	3,349	3,309	(40)	-1.2%	35.2%	36.3%	1.1%
13 Net Interchange	(5,721)	(5,897)	(176)	-3.1%	-60.1%	-64.6%	-4.5%
14 Total Output	9,524	9,123	(401)	-4.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,798	1,804	6	0.3%	18.9%	19.8%	0.9%
16 Native Requirement	7,726	7,319	(407)	-5.3%	81.1%	80.2%	-0.9%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.497	3.630	0.133	3.8%			
20 Nuclear	0.819	0.831	0.012	1.5%			
21 Purchases	3.951	3.806	-0.145	-3.7%			
22 Total System Costs	3.580	3.493	-0.087	-2.4%			
23 Intersystem Sales	1.669	1.506	-0.163	-9.8%			
24 Net System Costs	4.024	3.983	-0.042	-1.0%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,327	12,891	(436)	-3.3%			
28							
29 COST per KWH SALES (¢)	2.333	2.261	-0.072	-3.1%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.018	-0.426	-0.444				
(i) Residential	0.018	-0.425	-0.443				
(ii) C & I Non-Demand	0.019	-0.440	-0.458				
(iii) C & I Demand Non-TOD	0.019	-0.434	-0.453				
(iv) C & I Demand TOD On-Peak	0.023	-0.545	-0.569				
(v) C & I Demand TOD Off-Peak	0.014	-0.339	-0.353				
(vi) Outdoor Lighting	0.013	-0.313	-0.326				
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)	2.351	1.835	-0.516	-22.0%			
(i) Residential	2.332	1.829	-0.503				
(ii) C & I Non-Demand	2.414	1.893					
(iii) C & I Demand Non-TOD	2.383	1.869					
(iv) C & I Demand TOD On-Peak	2.994	2.348					
(v) C & I Demand TOD Off-Peak	1.861	1.459					
(vi) Outdoor Lighting	1.717	1.347					

Residential BILL IMPACT (\$'s)

Calculations:

[4] = [1]+[2]+[3]
 [6] = [4] - [5]
 [14] = [9]+..+[13]
 [16] = [14] - [15]
 [19] = [1] / [9]
 [20] = [2] / [10]

[21] = [3] / [11]
 [22] = [4] / [14]
 [23] = [5] / [15]
 [24] = [6] / [16]
 [29] = [6] / [27]
 [33] = [29]+[31]

kWh	Change from Previous Month
100	(\$0.50)
250	(\$1.26)
500	(\$2.51)
750	(\$3.77)
1,000	(\$5.03)

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>	
	Jun-16	Jul-16
** GWH OUTPUT **		
Thermal	2,234,344	2,185,668
Disper gen	(48)	(46)
<u>Hydro plus Wind</u>	1,114,242	1,123,627
Hydro and Other	3,348,538	3,309,249
Rounded to nearest thousand:	3,349	3,309
<u>Sales</u>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,797,540,000	1,803,830,000
Rounded to nearest million:	1797.54	1803.83

Northern States Power Company
Electric Operations - State of North Dakota

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

	Without PPAs Exclusion	With PPAs Exclusion	Difference	Adjustment to ND Fuel Cost
PPAs Replacement Cost				
System Fuel Costs	\$73,830,149	\$73,830,149		
Less: PPAs Exclusion				
15 C-BED Wind PPAs	\$0	(\$3,780,458)		
2 Solar PPAs	\$0	(\$45,686)		
Wind Curtailment Payments	\$0	(\$175,684)		
Total Exclusion	<u>\$0</u>	<u>(\$4,001,828)</u>		
Net System Costs	\$73,830,149	\$69,828,321		
Billing Month System Sales	3094585	3094585		
Billing Month North Dakota Sales	166345	166345		
North Dakota Percentage	5.3754%	5.3754%		
Affected PPAs Volume (System)	63189	63189		
Affected PPAs Volume (North Dakota's Share)	3397	3397		
Billing Month System Sales	3094585	3094585		
Less: Affected PPAs Volume		<u>-63189</u>		
Net System Billing Month Sales	<u>3094585</u>	<u>3031396</u>		
Billing Month North Dakota Sales	166345	166345		
Less: Affected PPAs Volume		<u>-3397</u>		
Net North Dakota Billing Month Sales	<u>166345</u>	<u>162948</u>		
System Fuel Costs	\$73,830,149	\$69,828,321		
North Dakota Percentage	5.3754%	5.3754%		
North Dakota Fuel Cost	\$3,968,666	\$3,753,552	(\$215,114)	
Affected PPAs Volume (System)		63189		
North Dakota Average System Cost (\$/MWh)		\$23.04		
North Dakota Replacement Cost	\$0	\$1,455,561		
Affected PPAs Volume (North Dakota's Share)		3397		
North Dakota Average System Cost (\$/MWh)		\$23.04		
North Dakota Replacement Cost	\$0	\$78,250	\$78,250	
Adjusted PPA Cost Added to ND FCA Calculation				(\$136,864)
Fuel Cost Impact Due to PPA Exclusion				(\$0.00084)
Residential Fuel Cost Charge Impact (750 kWh Use)				(\$0.63)

		System	Intersystem	Retail
May 2016 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 1,903,282.78	\$ 3,660,007.06	\$ 5,563,289.84
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,635,718.52	\$ -	\$ 1,635,718.52
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ (1,002.89)	\$ -	\$ (1,002.89)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (8,631,057.15)	\$ -	\$ (8,631,057.15)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 999,416.43	\$ -	\$ 999,416.43
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ 1,002.89	\$ -	\$ 1,002.89
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (1,392,570.33)	\$ 647,739.20	\$ (744,831.13)
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 54,203.17	\$ -	\$ 54,203.17
14	Real-Time Distribution of Losses Amount	\$ (586,154.43)	\$ -	\$ (586,154.43)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (731,048.92)	\$ -	\$ (731,048.92)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 17,318.67	\$ -	\$ 17,318.67
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (661.97)	\$ -	\$ (661.97)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 3,269,099.16	\$ -	\$ 3,269,099.16
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (9,375.18)	\$ -	\$ (9,375.18)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,794,624.49	\$ -	\$ 1,794,624.49
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 9,375.18	\$ -	\$ 9,375.18
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 114,328.40	\$ -	\$ 114,328.40
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)	\$ (1,046.11)	\$ -	\$ (1,046.11)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,394,360.59)	\$ -	\$ (3,394,360.59)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (243,817.37)	\$ -	\$ (243,817.37)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (20,228.52)	\$ -	\$ (20,228.52)
37	Financial Transmission Guarantee Uplift Amount	\$ 24,475.48	\$ -	\$ 24,475.48
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,521,383.01	\$ -	\$ 1,521,383.01
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 89,420.26	\$ -	\$ 89,420.26
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (12,957.18)	\$ (10,198.91)	\$ (23,156.09)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 99,617.27	\$ -	\$ 99,617.27
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (6,317.73)	\$ 1,826.23	\$ (4,491.50)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (189,261.18)	\$ 25,770.76	\$ (163,490.42)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 566,372.19	\$ (17,405.30)	\$ 548,966.89
19	Real-Time Market Administration Amount	\$ 38,592.01	\$ (3,205.36)	\$ 35,386.65
29	Financial Transmission Rights Market Administration Amount	\$ 29,130.00	\$ -	\$ 29,130.00
33	Day-Ahead Schedule 24 Allocation Amount	\$ 87,134.81	\$ (2,795.97)	\$ 84,338.84
34	Real-Time Schedule 24 Allocation Amount	\$ (96,312.32)	\$ 107,593.47	\$ 11,281.15
35	Schedule 24 Admin Allocation	\$ -	\$ -	\$ -
Virtual Energy Charges				
12	Day-Ahead Virtual Energy Amount	\$ -	\$ -	\$ -
27	Real-Time Virtual Energy Amount	\$ -	\$ -	\$ -
Other MISO Charges				
20	Real-Time Miscellaneous Amount	\$ 25,178.84	\$ 9,706.72	\$ 34,885.56
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,985,759.86	\$ -	\$ 2,985,759.86
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,988,827.34)	\$ 38,183.66	\$ (2,950,643.68)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (203,542.70)	\$ -	\$ (203,542.70)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 31,176.35	\$ -	\$ 31,176.35
TOTAL MISO CHARGES		\$ (3,211,932.14)	\$ 4,457,221.56	\$ 1,245,289.42
SCHEDULE 24 (FOR RETAIL)				\$ 95,619.99
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 1,149,669.43

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
May 2016 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (171,726.95)		\$ (171,726.95)
2	Day-Ahead Spinning Reserve Amount	\$ (136,807.45)		\$ (136,807.45)
3	Day-Ahead Supplemental Reserve	\$ (42,584.90)		\$ (42,584.90)
4	Real-Time Regulation Amount	\$ 1,907.74	\$ 70,444.23	\$ 72,351.97
5	Real-Time Spinning Reserve Amount	\$ (26,902.10)	\$ 66,038.98	\$ 39,136.88
6	Real-Time Supplemental Reserve Amount.	\$ 3,610.01	\$ 699.97	\$ 4,309.98
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 16,027.06		\$ 16,027.06
7b	Real Time Excessive Energy Congestion			\$ -
7c	Real Time Excessive Energy Loss			\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,849,014.63		\$ 1,849,014.63
8b	Real Time Non Excessive Energy Congestion	\$ (80,367.36)		\$ (80,367.36)
8c	Real Time Non Excessive Energy Loss	\$ (40,299.36)		\$ (40,299.36)
9	Real Time Net Regulation Adjustment Amount	\$ 25,073.53	\$ (10,095.65)	\$ 14,977.88
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 106,607.12		\$ 106,607.12
11	Real Time Spinning Reserve Cost Distribution	\$ 127,400.96		\$ 127,400.96
12	Real Time Supplemental Reserve Cost Distribution	\$ 40,130.01		\$ 40,130.01
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 75,084.14	\$ (15,568.78)	\$ 59,515.36
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 1,746,167.08	\$ 111,518.75	\$ 1,857,685.83

North Dakota True-up Detail for July 2016					
	Fuel Recovery True Up	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Sharing Refund	Total
March Unrecovered Expenses	-\$2,043,824				-\$2,043,824
Less: March Recovery of February Unrecovered	\$212,702				\$212,702
Actual May Recovery	-\$4,139,768				-\$4,139,768
Less: Expected May Recovery	\$3,832,588				\$3,832,588
Asset Based Margin Sharing True-up		-\$321,749			-\$321,749
Non Asset Based Margin Sharing True-up			-\$14,131		-\$14,131
REC Sharing True-up				-\$668,179	-\$668,179
Miscellaneous Adjustment					\$0
Total Under/(Over) Recovered Expenses	-\$2,138,302	-\$321,749	-\$14,131	-\$668,179	-\$3,142,361
July Four Month Average MWh Sales	737,404	737,404	737,404	737,404	737,404
True-up Factor per KWH (cents/kWh)	(0.290)	(0.044)	(0.002)	(0.091)	(0.426)
Percent of Total	68%	10%	0%	21%	100%