



414 Nicollet Mall
Minneapolis, Minnesota 55401

— Via Electronic Filing —

February 29, 2016

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

Re: March 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 March 2016.

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

March 2016	Fuel Cost Charge (\$/kWh)
Residential	0.02073
C & I Non-Demand	0.02146
C & I Demand	0.02118
C & I Demand Time of Day On-Peak	0.02662
C & I Demand Time of Day Off-Peak	0.01654
Outdoor Lighting	0.01527

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 March 2016 FCC the net MISO Day 2 costs for January 2015 as recorded in Account 555. The MISO Day 2 cost recovery included in this March 2016 FCC is \$4,992,189, 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 March 2016 FCC the net MISO ASM costs for January 2016 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is \$2,751,553, 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 amount of \$288,922 has been included as a credit to the March 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 2015 Non-Asset Based Margin credit is \$50,462 and this credit amount is distributed equally each month over the following 12-month period. The refund reflected in the March 2016 FCC is \$9,259, or a credit of 0.004¢ per kWh. 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 RECs is credited to customers. (See Attachment 3, page 3). 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

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

- 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 are included in the FCR calculation. The Company agreed to forego any unrecovered portion the Prairie Rose PPA incurred prior to that February date. 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 March 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 Mar-2016

Mar-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02595	-\$0.00152	-\$0.00364	\$0.02080
Residential	\$0.02587	-\$0.00151	-\$0.00362	\$0.02073
C & I Non-Demand	\$0.02678	-\$0.00157	-\$0.00375	\$0.02146
C & I Demand Non-TOD	\$0.02643	-\$0.00155	-\$0.00370	\$0.02118
C & I Demand TOD On-Peak	\$0.03321	-\$0.00194	-\$0.00465	\$0.02662
C & I Demand TOD Off-Peak	\$0.02064	-\$0.00121	-\$0.00289	\$0.01654
Outdoor Lighting	\$0.01905	-\$0.00111	-\$0.00267	\$0.01527
Residential				
Residential Service	\$ 0.02587	\$ (0.00151)	\$ (0.00362)	\$ 0.02073
Residential TOD	\$ 0.02587	\$ (0.00151)	\$ (0.00362)	\$ 0.02073
Residential - Underground	\$ 0.02587	\$ (0.00151)	\$ (0.00362)	\$ 0.02073
Residential TOD - Underground	\$ 0.02587	\$ (0.00151)	\$ (0.00362)	\$ 0.02073
Energy Control - (Non-Demand)	\$ 0.02587	\$ (0.00151)	\$ (0.00362)	\$ 0.02073
Limit Off Peak	\$ 0.02587	\$ (0.00151)	\$ (0.00362)	\$ 0.02073
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
Limit Off Peak	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
Small General Service	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
Small General TOD - Metered	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
Small General TOD - Unmetered	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
Fire and Civil Defense Siren	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
Direct Current (Closed)	\$ 0.02678	\$ (0.00157)	\$ (0.00375)	\$ 0.02146
C & I Demand				
General Service	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
General TOD - On Peak	\$ 0.03321	\$ (0.00194)	\$ (0.00465)	\$ 0.02662
General TOD - Off Peak	\$ 0.02064	\$ (0.00121)	\$ (0.00289)	\$ 0.01654
Peak Controlled (Closed)	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Peak Controlled TOD (Closed) - On Peak	\$ 0.03321	\$ (0.00194)	\$ (0.00465)	\$ 0.02662
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02064	\$ (0.00121)	\$ (0.00289)	\$ 0.01654
Peak Controlled Tiered	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Peak Controlled Tiered TOD - On Peak	\$ 0.03321	\$ (0.00194)	\$ (0.00465)	\$ 0.02662
Peak Controlled Tiered TOD - Off Peak	\$ 0.02064	\$ (0.00121)	\$ (0.00289)	\$ 0.01654
Energy Controlled (Closed)	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Tier 1 Energy Controlled Rider	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Real Time Pricing - Firm - On Peak	\$ 0.03321	\$ (0.00194)	\$ (0.00465)	\$ 0.02662
Real Time Pricing - Firm - Off Peak	\$ 0.02064	\$ (0.00121)	\$ (0.00289)	\$ 0.01654
Real Time Pricing - Controllable - On Peak	\$ 0.03321	\$ (0.00194)	\$ (0.00465)	\$ 0.02662
Real Time Pricing - Controllable - Off Peak	\$ 0.02064	\$ (0.00121)	\$ (0.00289)	\$ 0.01654
Small Municipal Pumping	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Municipal Pumping	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Excess Energy - St. Anthony Falls	\$ 0.02643	\$ (0.00155)	\$ (0.00370)	\$ 0.02118
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01905	\$ (0.00111)	\$ (0.00267)	\$ 0.01527
Street Lighting System	\$ 0.01905	\$ (0.00111)	\$ (0.00267)	\$ 0.01527
Street Lighting Energy	\$ 0.01905	\$ (0.00111)	\$ (0.00267)	\$ 0.01527
Street Lighting Energy - Metered	\$ 0.01905	\$ (0.00111)	\$ (0.00267)	\$ 0.01527
Street Lighting Energy (Closed)	\$ 0.01905	\$ (0.00111)	\$ (0.00267)	\$ 0.01527
Street Lighting - City of St. Paul	\$ 0.01905	\$ (0.00111)	\$ (0.00267)	\$ 0.01527

	Column (A) Oct-15	Column (B) Nov-15	Column (C) Dec-15	Column (D) Jan-16	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$38,217,497	\$35,333,247	\$37,734,653	\$45,029,964	\$156,315,361
Account 518 - Nuclear Fuel	\$9,063,923	\$5,996,735	\$7,947,135	\$7,094,043	\$30,101,836
Account 555 - Purchased Power ¹	\$40,306,305	\$41,877,757	\$38,447,571	\$38,195,938	\$158,827,571
MISO Day 2 Charges	\$3,645,674	\$10,046,285	\$3,620,382	\$5,071,466	\$22,383,807
MISO Day 2 - Schedule 24	(\$88,223)	(\$73,445)	(\$99,023)	(\$79,278)	(\$339,968)
MISO - ASM Charges	\$1,630,903	\$886,033	\$3,158,072	\$2,751,558	\$8,426,566
Account 555 - Total MISO Charges	\$5,188,354	\$10,858,873	\$6,679,432	\$7,743,746	\$30,470,406
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$92,776,079	\$94,066,612	\$90,808,790	\$98,063,692	\$375,715,174
Less Fuel Cost of InterSystem Sales	(\$10,060,412)	(\$5,175,231)	(\$9,646,144)	(\$7,335,842)	(\$32,217,628)
Net System Costs	\$82,715,668	\$88,891,381	\$81,162,647	\$90,727,850	\$343,497,546
System MWh Sales					
Total NSP System Retail	3,365,965	2,890,835	3,447,524	3,530,598	13,234,922
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	3,365,965	2,890,835	3,447,524	3,530,598	13,234,922
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.457¢	3.075¢	2.354¢	2.570¢	2.595¢
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			2.595¢	0.9969	2.587¢
(ii) C & I Non-Demand			2.595¢	1.0318	2.678¢
(iii) C & I Demand Non-TOD			2.595¢	1.0184	2.643¢
(iv) C & I Demand TOD On-Peak			2.595¢	1.2798	3.321¢
(v) C & I Demand TOD Off-Peak			2.595¢	0.7954	2.064¢
(vi) Outdoor Lighting			2.595¢	0.7341	1.905¢
North Dakota Retail MWh Sales					
(i) Residential	50,103	45,184	73,189	87,368	255,844
(ii) C & I Non-Demand	8,075	7,195	10,393	11,753	37,416
(iii) C & I Demand Non-TOD	65,024	55,348	68,396	66,866	255,634
(iv) C & I Demand TOD On-Peak	18,112	16,463	18,251	15,332	68,158
(v) C & I Demand TOD Off-Peak	28,370	25,828	29,775	29,416	113,389
(vi) Outdoor Lighting	1,546	1,785	1,968	2,093	7,392
(vii) Total	171,230	151,803	201,972	212,828	737,833
Mar-2016 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Nov-15 Balance of Unrecovered Expenses)					Total
					Nov-15
					(\$1,173,260)

¹ Excludes demand-related expenses

Prior Expenses Recovered in Jan-2016 [Billing Record]		ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential		87,368	(\$52,191)
(ii) C & I Non-Demand		11,753	(\$7,337)
(iii) C & I Demand Non-TOD		66,866	(\$43,000)
(iv) C & I Demand TOD On-Peak		15,332	(\$12,066)
(v) C & I Demand TOD Off-Peak		29,416	(\$15,029)
(vi) Outdoor Lighting		2,093	(\$355)
(vii) Total		212,828	(\$129,978)

Actual Cost Should Have Been Recovered in Jan-16				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.570¢	0.000¢	212,828	\$5,469,680

Cost Recovered in Jan-16 [Billing Record]		ND Billed MWh Sales	Actual Recovery
(i) Residential		87,368	\$2,280,684
(ii) C & I Non-Demand		11,753	\$317,334
(iii) C & I Demand Non-TOD		66,866	\$1,782,156
(iv) C & I Demand TOD On-Peak		15,332	\$513,470
(v) C & I Demand TOD Off-Peak		29,416	\$612,607
(vi) Outdoor Lighting		2,093	\$39,993
(vii) Total		212,828	\$5,546,244

Total Balance of Unrecovered Expenses (Mar-16 Balance of Unrecovered Expenses)	
Mar-2016 Recovery Provision	(\$1,119,846)
4 Month ND Retail Total MWh Sales	737,833
Mar-2016 Recovery Provision per KWH	-0.152¢

Mar-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	-0.152¢	-0.151¢
(ii) C & I Non-Demand	1.0318	-0.152¢	-0.157¢
(iii) C & I Demand Non-TOD	1.0184	-0.152¢	-0.155¢
(iv) C & I Demand TOD On-Peak	1.2798	-0.152¢	-0.194¢
(v) C & I Demand TOD Off-Peak	0.7954	-0.152¢	-0.121¢
(vi) Outdoor Lighting	0.7341	-0.152¢	-0.111¢

Refunds/Additional Charges				
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
	(\$288,922)	(\$46,243)	(\$478,452)	(\$813,616)
(i) Residential	-0.129¢	-0.021¢	-0.213¢	-0.362¢
(ii) C & I Non-Demand	-0.133¢	-0.021¢	-0.221¢	-0.375¢
(iii) C & I Demand Non-TOD	-0.131¢	-0.021¢	-0.218¢	-0.370¢
(iv) C & I Demand TOD On-Peak	-0.165¢	-0.026¢	-0.274¢	-0.465¢
(v) C & I Demand TOD Off-Peak	-0.103¢	-0.016¢	-0.170¢	-0.289¢
(vi) Outdoor Lighting	-0.095¢	-0.015¢	-0.157¢	-0.267¢

Mar-2016 Factors		Total
(i) Residential		2.073¢
(ii) C & I Non-Demand		2.146¢
(iii) C & I Demand Non-TOD		2.118¢
(iv) C & I Demand TOD On-Peak		2.662¢
(v) C & I Demand TOD Off-Peak		1.654¢
(vi) Outdoor Lighting		1.527¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Feb-16	Mar-16	Differ- ence	Percent Change	FCA Application Feb-16	Mar-16	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$152.1	\$156.3	\$4.2	2.8%	39.9%	41.6%	1.7%
2 Nuclear	\$33.6	\$30.1	(\$3.4)	-10.3%	8.8%	8.0%	-0.8%
3 Purchases	\$164.4	\$158.8	(\$5.5)	-3.4%	43.1%	42.3%	-0.8%
MISO related Purchases	\$31.3	\$30.5	(\$0.8)	-2.6%	8.2%	8.1%	-0.1%
4 Total System Costs	381.3	375.7	(\$5.6)	-1.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$34.2	\$32.2	(\$2.0)	-5.8%	9.0%	8.6%	-0.4%
6 Net System Costs	\$347.1	\$343.5	(\$3.6)	-1.0%	91.0%	91.4%	0.4%
7							
** GWH OUTPUT **							
9 Fossil	4,607	4,847	240	5.2%	28.7%	33.1%	4.4%
10 Nuclear	4,054	3,707	(347)	-8.6%	25.3%	25.3%	0.0%
11 Purchases	4,272	4,138	(134)	-3.1%	26.6%	28.2%	1.6%
12 Hydro & Other	2,745	2,913	168	6.1%	17.1%	19.9%	2.8%
13 Net Interchange	376	(948)	(1,324)	-352.1%	2.3%	-6.5%	-8.8%
14 Total Output	16,054	14,657	(1,397)	-8.7%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,842	1,760	(81)	-4.4%	11.5%	12.0%	0.5%
16 Native Requirement	14,212	12,897	(1,316)	-9.3%	88.5%	88.0%	-0.5%
17							
** COST per KWH OUTPUT (¢) **							
19 Fossil	3.301	3.225	-0.076	-2.3%			
20 Nuclear	0.828	0.812	-0.016	-1.9%			
21 Purchases	3.848	3.838	-0.009	-0.2%			
22 Total System Costs	2.375	2.563	0.188	7.9%			
23 Intersystem Sales	1.857	1.830	-0.026	-1.4%			
24 Net System Costs	2.442	2.663	0.221	9.1%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,369	13,235	(134)	-1.0%			
28							
29 COST per KWH SALES (¢)	2.596	2.595	-0.001	0.0%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.006	-0.152	-0.145				
(i) Residential	-0.006	-0.151	-0.145				
(ii) C & I Non-Demand	-0.007	-0.157	-0.150				
(iii) C & I Demand Non-TOD	-0.006	-0.155	-0.148				
(iv) C & I Demand TOD On-Peak	-0.008	-0.194	-0.186				
(v) C & I Demand TOD Off-Peak	-0.005	-0.121	-0.116				
(vi) Outdoor Lighting	-0.005	-0.111	-0.107				
32 REFUND	0.357	-0.364	-0.721				
(i) Residential	0.358	-0.362					
(ii) C & I Non-Demand	0.367	-0.375					
(iii) C & I Demand Non-TOD	0.363	-0.370					
(iv) C & I Demand TOD On-Peak	0.460	-0.465					
(v) C & I Demand TOD Off-Peak	0.282	-0.289					
(vi) Outdoor Lighting	0.266	-0.267					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.947	2.079	-0.867	-29.4%			
(i) Residential	2.939	2.073	-0.866				
(ii) C & I Non-Demand	3.041	2.146					
(iii) C & I Demand Non-TOD	3.002	2.118					
(iv) C & I Demand TOD On-Peak	3.772	2.662					
(v) C & I Demand TOD Off-Peak	2.345	1.654					
(vi) Outdoor Lighting	2.164	1.527					

Residential BILL IMPACT (\$'s)

Calculations:

		Change from kWh Previous Month
[4] = [1]+[2]+[3]	[21] = [3] / [11]	
[6] = [4] - [5]	[22] = [4] / [14]	100 (\$0.87)
[14] = [9]+..+[13]	[23] = [5] / [15]	250 (\$2.16)
[16] = [14] - [15]	[24] = [6] / [16]	500 (\$4.33)
[19] = [1] / [9]	[29] = [6] / [27]	750 (\$6.49)
[20] = [2] / [10]	[33] = [29]+[31]	1,000 (\$8.66)

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>	
	Feb-16	Mar-16
** GWH OUTPUT **		
Thermal	1,968,590	2,021,132
Disper gen	(75)	(68)
<u>Hydro plus Wind</u>	776,198	892,108
Hydro and Other	2,744,713	2,913,172
Rounded to nearest thousand:	2,745	2,913
<u>Sales</u>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,841,708,000	1,760,378,000
Rounded to nearest million:	1841.708	1760.378

		System	Intersystem	Retail
January 2016 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 1,058,567.50	\$ 4,942,322.68	\$ 6,000,890.18
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,885,053.71	\$ -	\$ 2,885,053.71
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 3,425.24	\$ -	\$ 3,425.24
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (6,524,620.37)	\$ -	\$ (6,524,620.37)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 498,934.65	\$ -	\$ 498,934.65
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (3,425.24)	\$ -	\$ (3,425.24)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 598,900.77	\$ 1,188,959.01	\$ 1,787,859.78
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (4,407.52)	\$ -	\$ (4,407.52)
14	Real-Time Distribution of Losses Amount	\$ (1,483,744.46)	\$ -	\$ (1,483,744.46)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (192,702.88)	\$ -	\$ (192,702.88)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 13.15	\$ -	\$ 13.15
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (5.09)	\$ -	\$ (5.09)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,014,802.89	\$ -	\$ 1,014,802.89
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 1,928.72	\$ -	\$ 1,928.72
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 328,700.35	\$ -	\$ 328,700.35
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (1,928.72)	\$ -	\$ (1,928.72)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ (9,139.67)	\$ -	\$ (9,139.67)
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)	\$ (8.04)	\$ -	\$ (8.04)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (598,278.53)	\$ -	\$ (598,278.53)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (11,899.73)	\$ -	\$ (11,899.73)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 73,446.38	\$ -	\$ 73,446.38
37	Financial Transmission Guarantee Uplift Amount	\$ (72,033.63)	\$ -	\$ (72,033.63)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 847,747.47	\$ -	\$ 847,747.47
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 85,143.26	\$ -	\$ 85,143.26
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (161,378.93)	\$ 26,336.73	\$ (135,042.20)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 61,556.02	\$ -	\$ 61,556.02
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (30,005.93)	\$ (14,822.44)	\$ (44,828.37)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (106,348.56)	\$ 20,187.20	\$ (86,161.36)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 629,120.42	\$ (17,932.66)	\$ 611,187.76
19	Real-Time Market Administration Amount	\$ 46,128.84	\$ (5,387.46)	\$ 40,741.38
29	Financial Transmission Rights Market Administration Amount	\$ 27,851.04	\$ -	\$ 27,851.04
33	Day-Ahead Schedule 24 Allocation Amount	\$ 86,365.51	\$ (2,439.52)	\$ 83,925.99
34	Real-Time Schedule 24 Allocation Amount	\$ (101,463.72)	\$ 96,815.23	\$ (4,648.49)
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	\$ (56,138.65)	\$ 17,534.72	\$ (38,603.93)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,770,129.38	\$ -	\$ 3,770,129.38
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,771,745.17)	\$ 52,033.25	\$ (3,719,711.92)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (187,052.38)	\$ -	\$ (187,052.38)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 66,371.33	\$ -	\$ 66,371.33
TOTAL MISO CHARGES		\$ (1,232,140.59)	\$ 6,303,606.74	\$ 5,071,466.15
SCHEDULE 24 (FOR RETAIL)				\$ 79,277.50
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 4,992,188.65

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
January 2016 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (32,831.67)		\$ (32,831.67)
2	Day-Ahead Spinning Reserve Amount	\$ (94,129.19)		\$ (94,129.19)
3	Day-Ahead Supplemental Reserve	\$ (31,737.97)		\$ (31,737.97)
4	Real-Time Regulation Amount	\$ (15,850.66)	\$ 4,940.43	\$ (10,910.23)
5	Real-Time Spinning Reserve Amount	\$ (6,177.31)	\$ 37,661.38	\$ 31,484.07
6	Real-Time Supplemental Reserve Amount.	\$ 169.40	\$ 848.55	\$ 1,017.95
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 15,343.41		\$ 15,343.41
7b	Real Time Excessive Energy Congestion			\$ -
7c	Real Time Excessive Energy Loss			\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,666,036.28		\$ 2,666,036.28
8b	Real Time Non Excessive Energy Congestion	\$ 228.97		\$ 228.97
8c	Real Time Non Excessive Energy Loss	\$ 12,667.87		\$ 12,667.87
9	Real Time Net Regulation Adjustment Amount	\$ 2,868.67	\$ (820.54)	\$ 2,048.13
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 65,560.31		\$ 65,560.31
11	Real Time Spinning Reserve Cost Distribution	\$ 80,474.86		\$ 80,474.86
12	Real Time Supplemental Reserve Cost Distribution	\$ 34,779.64		\$ 34,779.64
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 24,050.30	\$ (12,530.04)	\$ 11,520.26
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 2,721,452.91	\$ 30,099.78	\$ 2,751,552.69

