



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

February 27, 2015

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

**Re: March 2015 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 2015.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2012 rate proceeding (Case No. PU-12-813), the new rates were implemented on May 1, 2014. The Service Category Ratios listed below also become effective:

<b>Service Category Ratios</b>	<b>Current</b>	<b>Effective May 2014</b>
<b>Residential</b>	1.0026	0.9969
<b>C &amp; I Non-Demand</b>	1.0281	1.0318
<b>C &amp; I Demand</b>	1.0170	1.0184
<b>C &amp; I Demand Time of Day On-Peak</b>	1.2883	1.2798
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.7889	0.7954
<b>Outdoor Lighting</b>	0.7440	0.7341

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

March 2015	Fuel Cost Charge (\$/kWh)
<b>Residential</b>	0.02349
<b>C &amp; I Non-Demand</b>	0.02432
<b>C &amp; I Demand</b>	0.02400
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03016
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.01874
<b>Outdoor Lighting</b>	0.01730

## **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 March 2009 FCC reflected the MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 Financial Transmission Rights (FTR) charge types<sup>1</sup>, to be reflected in the Fuel Cost Rider. Consistent with this Order and the required "net" accounting of Day 2 costs and revenues, we have included in the March 2015 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 2015 FCC is \$5,561,330, 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

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

MISO Order and the required “net” accounting of ASM costs and revenues, we include in the March 2015 FCC the net MISO ASM costs for January 2015 as recorded in Account 555. The MISO ASM cost recovery included in this March 2015 FCC is \$3,294,871, 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 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 North Dakota customers and will not do so unless, of course, the DOE reinstates a fee.

## **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 \$225,701 has been included as a credit, or offset, to the March 2015 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 will be distributed equally each month over the following 12-month period. The refund reflected in the March 2015 FCC is \$13,100, or 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

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<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.

<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

generated by the sale of Renewable Energy Credits was credited to customers. (See Attachment 3, page 3).

### **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 Fuel Cost Rider (FCR). Beginning with the March 2013 FCR filing, the Company has excluded the PRW PPA from any FCR calculations until the Commission has completed a ratemaking proceeding and made a decision regarding the rate treatment for the PRW PPA.

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.

### **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 March 2015 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.

## Other Reporting Item

Attached is the calculation of the March 2015 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 in Fargo at 701-241-8632.

Sincerely,

/ s /

PAUL J LEHMAN  
MANAGER, REGULATORY COMPLIANCE AND FILINGS

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 Mar-2015

Mar-2015 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02844	-\$0.00189	-\$0.00298	\$0.02357
<b>Residential</b>	\$0.02835	-\$0.00189	-\$0.00297	\$0.02349
<b>C &amp; I Non-Demand</b>	\$0.02934	-\$0.00195	-\$0.00308	\$0.02432
<b>C &amp; I Demand Non-TOD</b>	\$0.02896	-\$0.00193	-\$0.00304	\$0.02400
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03640	-\$0.00242	-\$0.00382	\$0.03016
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02262	-\$0.00151	-\$0.00237	\$0.01874
<b>Outdoor Lighting</b>	\$0.02088	-\$0.00139	-\$0.00219	\$0.01730
<b>Residential</b>				
Residential Service	\$ 0.02835	\$ (0.00189)	\$ (0.00297)	\$ 0.02349
Residential TOD	\$ 0.02835	\$ (0.00189)	\$ (0.00297)	\$ 0.02349
Residential - Underground	\$ 0.02835	\$ (0.00189)	\$ (0.00297)	\$ 0.02349
Residential TOD - Underground	\$ 0.02835	\$ (0.00189)	\$ (0.00297)	\$ 0.02349
Energy Control - (Non-Demand)	\$ 0.02835	\$ (0.00189)	\$ (0.00297)	\$ 0.02349
Limit Off Peak	\$ 0.02835	\$ (0.00189)	\$ (0.00297)	\$ 0.02349
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
Limit Off Peak	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
Small General Service	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
Small General TOD - Metered	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
Small General TOD - Unmetered	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
Fire and Civil Defense Siren	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
Direct Current (Closed)	\$ 0.02934	\$ (0.00195)	\$ (0.00308)	\$ 0.02432
<b>C &amp; I Demand</b>				
General Service	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
General TOD - On Peak	\$ 0.03640	\$ (0.00242)	\$ (0.00382)	\$ 0.03016
General TOD - Off Peak	\$ 0.02262	\$ (0.00151)	\$ (0.00237)	\$ 0.01874
Peak Controlled (Closed)	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
Peak Controlled TOD (Closed) - On Peak	\$ 0.03640	\$ (0.00242)	\$ (0.00382)	\$ 0.03016
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02262	\$ (0.00151)	\$ (0.00237)	\$ 0.01874
Peak Controlled Tiered	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
Peak Controlled Tiered TOD - On Peak	\$ 0.03640	\$ (0.00242)	\$ (0.00382)	\$ 0.03016
Peak Controlled Tiered TOD - Off Peak	\$ 0.02262	\$ (0.00151)	\$ (0.00237)	\$ 0.01874
Energy Controlled (Closed)	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
Tier 1 Energy Controlled Rider	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
Real Time Pricing - Firm - On Peak	\$ 0.03640	\$ (0.00242)	\$ (0.00382)	\$ 0.03016
Real Time Pricing - Firm - Off Peak	\$ 0.02262	\$ (0.00151)	\$ (0.00237)	\$ 0.01874
Real Time Pricing - Controllable - On Peak	\$ 0.03640	\$ (0.00242)	\$ (0.00382)	\$ 0.03016
Real Time Pricing - Controllable - Off Peak	\$ 0.02262	\$ (0.00151)	\$ (0.00237)	\$ 0.01874
Small Municipal Pumping	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
Municipal Pumping	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
Excess Energy - St. Anthony Falls	\$ 0.02896	\$ (0.00193)	\$ (0.00304)	\$ 0.02400
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.02088	\$ (0.00139)	\$ (0.00219)	\$ 0.01730
Street Lighting System	\$ 0.02088	\$ (0.00139)	\$ (0.00219)	\$ 0.01730
Street Lighting Energy	\$ 0.02088	\$ (0.00139)	\$ (0.00219)	\$ 0.01730
Street Lighting Energy - Metered	\$ 0.02088	\$ (0.00139)	\$ (0.00219)	\$ 0.01730
Street Lighting Energy (Closed)	\$ 0.02088	\$ (0.00139)	\$ (0.00219)	\$ 0.01730
Street Lighting - City of St. Paul	\$ 0.02088	\$ (0.00139)	\$ (0.00219)	\$ 0.01730

	Column (A) Oct-14	Column (B) Nov-14	Column (C) Dec-14	Column (D) Jan-15	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$47,290,204	\$42,328,130	\$51,460,555	\$44,941,924	\$186,020,813
Account 518 - Nuclear Fuel	\$5,755,755	\$7,073,944	\$8,700,192	\$10,473,127	\$32,003,018
Account 555 - Purchased Power <sup>1</sup>	\$40,492,666	\$48,502,403	\$39,600,500	\$41,184,349	\$169,779,918
MISO Day 2 Charges	\$7,791,951	\$9,407,951	\$4,418,667	\$5,629,384	\$27,247,953
MISO Day 2 - Schedule 24	(\$67,443)	(\$73,700)	(\$64,885)	(\$68,054)	(\$274,083)
MISO - ASM Charges	<u>\$2,501,452</u>	<u>\$3,944,007</u>	<u>\$5,059,791</u>	<u>\$3,294,871</u>	<u>\$14,800,121</u>
Account 555 - Total MISO Charges	\$10,225,960	\$13,278,258	\$9,413,573	\$8,856,201	\$41,773,991
Financial Instruments	\$0	\$0	\$0	\$0	\$0
<b>Total System Costs</b>	<b>\$103,764,585</b>	<b>\$111,182,735</b>	<b>\$109,174,820</b>	<b>\$105,455,601</b>	<b>\$429,577,741</b>
Less Fuel Cost of InterSystem Sales	(\$10,015,322)	(\$8,724,508)	(\$12,051,483)	(\$9,742,335)	(\$40,533,649)
<b>Net System Costs</b>	<b>\$93,749,263</b>	<b>\$102,458,227</b>	<b>\$97,123,336</b>	<b>\$95,713,266</b>	<b>\$389,044,092</b>
<b>System MWh Sales</b>					
Total NSP System Retail	3,325,315	2,859,179	3,698,615	3,798,198	13,681,307
Non-Gen Muni's/Load Pattern	-	-	-	-	-
<b>Total NSP System MWh Sales</b>	<b>3,325,315</b>	<b>2,859,179</b>	<b>3,698,615</b>	<b>3,798,198</b>	<b>13,681,307</b>
<b>Average Unit Cost of Fuel and Purchased Power</b>					
<b>Fuel Cost per kWh for NSP System</b>					
Adjusted System Cost without Pr. Rose PPA	2.819¢	3.583¢	2.626¢	2.520¢	2.844¢
<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			2.844¢	0.9969	2.835¢
(ii) C & I Non-Demand			2.844¢	1.0318	2.934¢
(iii) C & I Demand Non-TOD			2.844¢	1.0184	2.896¢
(iv) C & I Demand TOD On-Peak			2.844¢	1.2798	3.640¢
(v) C & I Demand TOD Off-Peak			2.844¢	0.7954	2.262¢
(vi) Outdoor Lighting			2.844¢	0.7341	2.088¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	52,181	48,241	88,017	97,052	285,491
(ii) C & I Non-Demand	8,558	7,710	12,414	13,474	42,156
(iii) C & I Demand Non-TOD	65,501	52,553	74,067	71,260	263,381
(iv) C & I Demand TOD On-Peak	20,499	16,235	18,800	17,107	72,641
(v) C & I Demand TOD Off-Peak	32,253	25,082	28,581	32,599	118,515
(vi) Outdoor Lighting	1,563	1,695	1,970	2,074	7,302
<b>(vii) Total</b>	<b>180,555</b>	<b>151,516</b>	<b>223,849</b>	<b>233,566</b>	<b>789,486</b>
<b>Mar-2015 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Nov-14 Balance of Unrecovered Expenses)					Total
					Nov-14
					(\$1,116,982)

<sup>1</sup> Excludes demand-related expenses and includes Prairie Rose Wind PPA expenses

Prior Expenses Recovered in Jan-2015 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	97,052	(\$38,068)
(ii) C & I Non-Demand	13,474	(\$6,057)
(iii) C & I Demand Non-TOD	71,260	(\$34,618)
(iv) C & I Demand TOD On-Peak	17,107	(\$9,813)
(v) C & I Demand TOD Off-Peak	32,599	(\$12,945)
(vi) Outdoor Lighting	2,074	\$23
(vii) Total	233,566	(\$101,478)

Actual Cost Should Have Been Recovered in Jan-15				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.520¢	0.000¢	233,566	\$5,885,863

Cost Recovered in Jan-15 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	97,052	\$2,650,676
(ii) C & I Non-Demand	13,474	\$380,453
(iii) C & I Demand Non-TOD	71,260	\$1,984,374
(iv) C & I Demand TOD On-Peak	17,107	\$599,138
(v) C & I Demand TOD Off-Peak	32,599	\$708,808
(vi) Outdoor Lighting	2,074	\$41,197
(vii) Total	233,566	\$6,364,646

Total Balance of Unrecovered Expenses (Mar-15 Balance of Unrecovered Expenses)	
Mar-2015 Recovery Provision	(\$1,494,287)
4 Month ND Retail Total MWh Sales	789,486
Mar-2015 Recovery Provision per KWH	-0.189¢

Mar-2015 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	-0.189¢	-0.189¢
(ii) C & I Non-Demand	1.0318	-0.189¢	-0.195¢
(iii) C & I Demand Non-TOD	1.0184	-0.189¢	-0.193¢
(iv) C & I Demand TOD On-Peak	1.2798	-0.189¢	-0.242¢
(v) C & I Demand TOD Off-Peak	0.7954	-0.189¢	-0.151¢
(vi) Outdoor Lighting	0.7341	-0.189¢	-0.139¢

Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	(\$225,701)	(\$13,100)	(\$401,239)	(\$626,940)
(i) Residential	-0.105¢	-0.006¢	-0.186¢	-0.297¢
(ii) C & I Non-Demand	-0.108¢	-0.006¢	-0.193¢	-0.308¢
(iii) C & I Demand Non-TOD	-0.107¢	-0.006¢	-0.190¢	-0.304¢
(iv) C & I Demand TOD On-Peak	-0.135¢	-0.008¢	-0.239¢	-0.382¢
(v) C & I Demand TOD Off-Peak	-0.084¢	-0.005¢	-0.149¢	-0.237¢
(vi) Outdoor Lighting	-0.077¢	-0.004¢	-0.137¢	-0.219¢

Mar-2015 Factors	
	Total
(i) Residential	2.349¢
(ii) C & I Non-Demand	2.432¢
(iii) C & I Demand Non-TOD	2.400¢
(iv) C & I Demand TOD On-Peak	3.016¢
(v) C & I Demand TOD Off-Peak	1.874¢
(vi) Outdoor Lighting	1.730¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Feb-15	Mar-15	Difference	Percent Change	FCA Application Feb-15	Mar-15	Difference
** COSTS (Millions) **							
1 Fossil	\$177.8	\$186.0	\$8.2	4.6%	42.9%	43.3%	0.4%
2 Nuclear	\$31.2	\$32.0	\$0.8	2.6%	7.5%	7.4%	-0.1%
3 Purchases	\$165.3	\$169.8	\$4.5	2.7%	39.9%	39.5%	-0.4%
MISO related Purchases	\$40.0	\$41.8	\$1.8	4.4%	9.7%	9.7%	0.0%
4 Total System Costs	414.3	429.6	\$15.3	3.7%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$35.3	\$40.5	\$5.2	14.8%	8.5%	9.4%	0.9%
6 Net System Costs	\$379.0	\$389.0	\$10.1	2.7%	91.5%	90.6%	-0.9%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,724	5,924	200	3.5%	36.1%	36.3%	0.2%
10 Nuclear	3,557	3,675	118	3.3%	22.4%	22.5%	0.1%
11 Purchases	4,068	4,099	31	0.8%	25.6%	25.1%	-0.5%
12 Hydro & Other	1,737	1,836	99	5.7%	10.9%	11.2%	0.3%
13 Net Interchange	790	803	13	1.6%	5.0%	4.9%	-0.1%
14 Total Output	15,876	16,337	461	2.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,431	1,531	100	7.0%	9.0%	9.4%	0.4%
16 Native Requirement	14,445	14,806	361	2.5%	91.0%	90.6%	-0.4%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	3.106	3.140	0.034	1.1%			
20 Nuclear	0.877	0.871	-0.006	-0.7%			
21 Purchases	4.062	4.142	0.079	2.0%			
22 Total System Costs	2.609	2.629	0.020	0.8%			
23 Intersystem Sales	2.468	2.647	0.179	7.3%			
24 Net System Costs	2.623	2.628	0.004	0.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,615	13,681	66	0.5%			
28							
29 COST per KWH SALES (\$)	2.783	2.844	0.061	2.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.102	-0.189	-0.291				
(i) Residential	0.102	-0.189	-0.290				
(ii) C & I Non-Demand	0.105	-0.195	-0.301				
(iii) C & I Demand Non-TOD	0.104	-0.193	-0.297				
(iv) C & I Demand TOD On-Peak	0.131	-0.242	-0.373				
(v) C & I Demand TOD Off-Peak	0.081	-0.151	-0.232				
(vi) Outdoor Lighting	0.075	-0.139	-0.214				
32 REFUND	0.153	-0.298	-0.451				
(i) Residential	0.153	-0.297	-0.450				
(ii) C & I Non-Demand	0.157	-0.308	-0.465				
(iii) C & I Demand Non-TOD	0.156	-0.304	-0.460				
(iv) C & I Demand TOD On-Peak	0.197	-0.382	-0.579				
(v) C & I Demand TOD Off-Peak	0.121	-0.237	-0.358				
(vi) Outdoor Lighting	0.114	-0.219	-0.333				
33 SYSTEM FCC IMPACT (\$ / KWH)	3.038	2.357	-0.681	-22.4%			
(i) Residential	3.029	2.349	-0.680				
(ii) C & I Non-Demand	3.135	2.432	-0.703				
(iii) C & I Demand Non-TOD	3.094	2.400	-0.694				
(iv) C & I Demand TOD On-Peak	3.888	3.016	-0.872				
(v) C & I Demand TOD Off-Peak	2.416	1.874	-0.542				
(vi) Outdoor Lighting	2.230	1.730	-0.500				

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

Calculations:

[ 4 ] = [1]+[2]+[3]	[21] = [3] / [11]
[ 6 ] = [4] - [5]	[22] = [4] / [14]
[14] = [9]+...+[13]	[23] = [5] / [15]
[16] = [14] - [15]	[24] = [6] / [16]
[19] = [1] / [9]	[29] = [6] / [27]
[20] = [2] / [10]	[33] = [29]+[31]

kWh	Change from Previous Month
100	(\$0.68)
250	(\$1.70)
500	(\$3.40)
750	(\$5.10)
1,000	(\$6.80)

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-15	Mar-15
<b>** GWH OUTPUT **</b>		
Thermal	1,065,405	1,205,145
Disper gen	(82)	(84)
Hydro plus Wind	671,428	630,879
Hydro and Other	1,736,751	1,835,940
Rounded to nearest thousand:	1,737	1,836
<b>Sales</b>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,431,225,000	1,531,319,000
Rounded to nearest million:	1431.225	1531.319

		System	Intersystem	Retail
<b>January 2015 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 2,591,924.99	\$ 5,156,228.15	\$ 7,748,153.14
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 5,018,262.73	\$ -	\$ 5,018,262.73
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 3,961.72	\$ -	\$ 3,961.72
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (8,128,583.31)	\$ -	\$ (8,128,583.31)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ (850,409.95)	\$ -	\$ (850,409.95)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (3,961.72)	\$ -	\$ (3,961.72)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 1,448,654.35	\$ 1,151,464.36	\$ 2,600,118.71
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (85,017.45)	\$ -	\$ (85,017.45)
14	Real-Time Distribution of Losses Amount	\$ (1,511,371.31)	\$ -	\$ (1,511,371.31)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ (23.77)	\$ -	\$ (23.77)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ 23.77	\$ -	\$ 23.77
21	Real-time Net inadvertent Distribution	\$ (96,680.24)	\$ -	\$ (96,680.24)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 8,020.62	\$ -	\$ 8,020.62
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 1,734.88	\$ -	\$ 1,734.88
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 3,503,488.11	\$ -	\$ 3,503,488.11
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 845.35	\$ -	\$ 845.35
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 453,878.46	\$ -	\$ 453,878.46
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (845.35)	\$ -	\$ (845.35)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ (292,699.49)	\$ -	\$ (292,699.49)
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ (12.51)	\$ -	\$ (12.51)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 12.51	\$ -	\$ 12.51
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (2,336.69)	\$ -	\$ (2,336.69)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,088,429.08)	\$ -	\$ (3,088,429.08)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (187,254.82)	\$ -	\$ (187,254.82)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (54,659.01)	\$ -	\$ (54,659.01)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 46,900.17	\$ -	\$ 46,900.17
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 379,920.53	\$ -	\$ 379,920.53
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 163,641.43	\$ -	\$ 163,641.43
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (111,103.02)	\$ 45,145.06	\$ (65,957.96)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 116,402.97	\$ -	\$ 116,402.97
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (1,267.67)	\$ (798.19)	\$ (2,065.86)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (348,515.12)	\$ 15,204.93	\$ (333,310.19)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 500,873.36	\$ (12,091.60)	\$ 488,781.76
19	Real-Time Market Administration Amount	\$ 37,302.32	\$ (3,163.81)	\$ 34,138.51
29	Financial Transmission Rights Market Administration Amount	\$ 38,159.60	\$ -	\$ 38,159.60
33	Day-Ahead Schedule 24 Allocation Amount	\$ 63,799.38	\$ (1,528.00)	\$ 62,271.38
34	Real-Time Schedule 24 Allocation Amount	\$ (29,413.48)	\$ 35,196.11	\$ 5,782.63
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	\$ (405,509.67)	\$ 95,051.51	\$ (310,458.16)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 7,250,896.00	\$ -	\$ 7,250,896.00
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (7,412,271.29)	\$ 19,168.06	\$ (7,393,103.23)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (104,620.47)	\$ -	\$ (104,620.47)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 215,789.60	\$ -	\$ 215,789.60
<b>TOTAL MISO CHARGES</b>		<b>\$ (870,492.57)</b>	<b>\$ 6,499,876.58</b>	<b>\$ 5,629,384.01</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 68,054.01</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 5,561,330.00</b>

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

		System	Intersystem	Retail
<b>January 2015 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (52,138.62)	\$ -	\$ (52,138.62)
2	Day-Ahead Spinning Reserve Amount	\$ (94,663.06)	\$ -	\$ (94,663.06)
3	Day-Ahead Supplemental Reserve	\$ (30,650.87)	\$ -	\$ (30,650.87)
4	Real-Time Regulation Amount	\$ 10,736.61	\$ 1,250.43	\$ 11,987.04
5	Real-Time Spinning Reserve Amount	\$ 7,712.52	\$ 44,830.04	\$ 52,542.56
6	Real-Time Supplemental Reserve Amount	\$ (3,863.61)	\$ 9,278.27	\$ 5,414.66
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (22,436.29)		\$ (22,436.29)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 3,064,031.95		\$ 3,064,031.95
8b	Real Time Non Excessive Energy Congestion	\$ 159,062.03		\$ 159,062.03
8c	Real Time Non Excessive Energy Loss	\$ 12,139.90		\$ 12,139.90
9	Real Time Net Regulation Adjustment Amount	\$ 1,170.48	\$ (794.72)	\$ 375.76
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 80,868.66	\$ -	\$ 80,868.66
11	Real Time Spinning Reserve Cost Distribution	\$ 66,431.35	\$ -	\$ 66,431.35
12	Real Time Supplemental Reserve Cost Distribution	\$ 19,211.25	\$ -	\$ 19,211.25
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 22,746.18	\$ (1,036.99)	\$ 21,709.19
14	Real Time Contingency Reserve Deployment Failure	\$ 985.06	\$ -	\$ 985.06
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 3,241,343.54</b>	<b>\$ 53,527.03</b>	<b>\$ 3,294,870.57</b>





