



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

March 30, 2012

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

**Re: April 2012 Fuel Cost Charge**

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits its electric fuel cost charge (“FCC”) for April 2012.

Pursuant to the Commission authorization of the final compliance tariffs in the Company’s 2007 rate proceeding (Case No. PU-07-776) to implement new rates beginning March 1, 2009, a “multi-class” fuel cost mechanism replaced the previous single-factor mechanism. The April 2012 system FCC is based on the average of the most recent four-month actual fuel cost plus a “true-up” factor, reflecting cost recovery deviations during the February 2012 calendar month.

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

<b>April 2012</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02602
<b>C &amp; I Non-Demand</b>	0.02757
<b>C &amp; I Demand</b>	0.02671
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03433
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02019
<b>Outdoor Lighting</b>	0.01852

## **MISO CHARGES IMPLEMENTATION**

### MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent Transmission System Operator, Inc. (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005 and the Order in Docket No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (“ARR”) and 3 new 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 April 2012 FCC, the net MISO Day 2 costs for February 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this April FCC is \$10,003,410.66, 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 new ASM charge types are included in the Fuel

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

Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the April FCC, the net MISO ASM costs for February 2012 as recorded in Account 555. The MISO ASM cost recovery included in this April FCC is \$427,337, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

## **REFUNDS**

Pursuant to the above referenced Order Adopting Settlement, the February 2012 Asset Based Margin amount of \$58,058 has been included in the April 2012 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the 2010 retail share of the Non-Asset Based Margins will be 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 2011 Non-Asset Based Margin credit is \$141,551 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the April FCC is \$13,816, or 0.008¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **ACCOUNTING CHANGE ON INTERSYSTEM SALES**

Beginning February 2012 there has been accounting changes on intersystem sales that better reflected the nature of certain transactions. However this change will correspondingly offset by equal amount of purchases therefore has no affect on retail FCC. The company provides detail analysis in this month’s FCC filing (See attachment 4, Page 1 of 1).

## **OTHER REPORTING ITEM**

Attached is the calculation of the April 2012 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 /

Phillip J. Zins  
Manager, Pricing and Planning  
Enclosures (2)  
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Apr-2012

Apr-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02659	-\$0.00005	-\$0.00041	\$0.02613
<b>Residential</b>	\$0.02647	-\$0.00005	-\$0.00041	\$0.02602
<b>C &amp; I Non-Demand</b>	\$0.02805	-\$0.00005	-\$0.00043	\$0.02757
<b>C &amp; I Demand Non-TOD</b>	\$0.02717	-\$0.00005	-\$0.00042	\$0.02671
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03493	-\$0.00006	-\$0.00054	\$0.03433
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02054	-\$0.00004	-\$0.00032	\$0.02019
<b>Outdoor Lighting</b>	\$0.01885	-\$0.00003	-\$0.00029	\$0.01852
<b>Residential</b>				
Residential Service	\$ 0.02647	\$ (0.00005)	\$ (0.00041)	\$ 0.02602
Residential TOD	\$ 0.02647	\$ (0.00005)	\$ (0.00041)	\$ 0.02602
Residential - Underground	\$ 0.02647	\$ (0.00005)	\$ (0.00041)	\$ 0.02602
Residential TOD - Underground	\$ 0.02647	\$ (0.00005)	\$ (0.00041)	\$ 0.02602
Energy Control - (Non-Demand)	\$ 0.02647	\$ (0.00005)	\$ (0.00041)	\$ 0.02602
Limit Off Peak	\$ 0.02647	\$ (0.00005)	\$ (0.00041)	\$ 0.02602
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
Limit Off Peak	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
Small General Service	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
Small General TOD - Metered	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
Small General TOD - Unmetered	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
Fire and Civil Defense Siren	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
Direct Current (Closed)	\$ 0.02805	\$ (0.00005)	\$ (0.00043)	\$ 0.02757
<b>C &amp; I Demand</b>				
General Service	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
General TOD - On Peak	\$ 0.03493	\$ (0.00006)	\$ (0.00054)	\$ 0.03433
General TOD - Off Peak	\$ 0.02054	\$ (0.00004)	\$ (0.00032)	\$ 0.02019
Peak Controlled (Closed)	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
Peak Controlled TOD (Closed) - On Peak	\$ 0.03493	\$ (0.00006)	\$ (0.00054)	\$ 0.03433
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02054	\$ (0.00004)	\$ (0.00032)	\$ 0.02019
Peak Controlled Tiered	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
Peak Controlled Tiered TOD - On Peak	\$ 0.03493	\$ (0.00006)	\$ (0.00054)	\$ 0.03433
Peak Controlled Tiered TOD - Off Peak	\$ 0.02054	\$ (0.00004)	\$ (0.00032)	\$ 0.02019
Energy Controlled (Closed)	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
Tier 1 Energy Controlled Rider	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
Real Time Pricing - Firm - On Peak	\$ 0.03493	\$ (0.00006)	\$ (0.00054)	\$ 0.03433
Real Time Pricing - Firm - Off Peak	\$ 0.02054	\$ (0.00004)	\$ (0.00032)	\$ 0.02019
Real Time Pricing - Controllable - On Peak	\$ 0.03493	\$ (0.00006)	\$ (0.00054)	\$ 0.03433
Real Time Pricing - Controllable - Off Peak	\$ 0.02054	\$ (0.00004)	\$ (0.00032)	\$ 0.02019
Small Municipal Pumping	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
Municipal Pumping	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
Excess Energy - St. Anthony Falls	\$ 0.02717	\$ (0.00005)	\$ (0.00042)	\$ 0.02671
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01885	\$ (0.00003)	\$ (0.00029)	\$ 0.01852
Street Lighting System	\$ 0.01885	\$ (0.00003)	\$ (0.00029)	\$ 0.01852
Street Lighting Energy	\$ 0.01885	\$ (0.00003)	\$ (0.00029)	\$ 0.01852
Street Lighting Energy - Metered	\$ 0.01885	\$ (0.00003)	\$ (0.00029)	\$ 0.01852
Street Lighting Energy (Closed)	\$ 0.01885	\$ (0.00003)	\$ (0.00029)	\$ 0.01852
Street Lighting - City of St. Paul	\$ 0.01885	\$ (0.00003)	\$ (0.00029)	\$ 0.01852

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Apr-2012

	Column (A) Nov-11	Column (B) Dec-11	Column (C) Jan-12	Column (D) Feb-12	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$29,246,148	\$35,655,438	\$35,849,644	\$40,360,850	\$141,112,080
Account 518 - Nuclear Fuel	\$9,550,563	\$10,116,633	\$11,312,463	\$9,507,504	\$40,487,162
Account 555 - Purchased Power <sup>1</sup>	\$45,056,103	\$33,477,192	\$41,565,189	\$33,040,802	\$153,139,287
Account 555 - MISO Day 2 Charges	\$14,479,922	\$16,418,488	\$11,190,335	\$10,098,736	\$52,187,481
Account 555 MISO Day 2 - Schedule 24	(\$94,807)	(\$97,206)	(\$97,091)	(\$95,325)	(\$384,429)
Account 555 MISO - ASM Charges	\$1,656,473	\$1,795,071	\$1,785,816	\$427,337	\$5,664,696
Total MISO Charges	\$16,041,588	\$18,116,353	\$12,879,060	\$10,430,748	\$57,467,748
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$99,894,402	\$97,365,616	\$101,606,355	\$93,339,903	\$392,206,277
Less Fuel Cost of InterSystem Sales	(\$12,667,019)	(\$3,793,539)	(\$5,272,759)	(\$5,459,934)	(\$27,193,252)
Net System Costs	\$87,227,383	\$93,572,077	\$96,333,596	\$87,879,969	\$365,013,025
<b>System MWh Sales</b>					
Total NSP System Retail	3,063,600	3,404,903	3,719,673	3,348,071	13,536,247
Non-Gen Muni's/Load Pattern	44,747	45,419	49,936	51,225	191,327
Total NSP System MWh Sales	3,108,347	3,450,322	3,769,609	3,399,296	13,727,574
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.806¢	2.712¢	2.556¢	2.585¢	2.659¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
<b>Class Ratio/TOD Ratio</b>					
(i) Residential	0.9956	0.9956	0.9956	0.9956	0.9956
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088
<b>North Dakota Fuel Cost Factor (FCF)</b>					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.647¢
(ii) C & I Non-Demand				1.0548	2.805¢
(iii) C & I Demand Non-TOD				1.0219	2.717¢
(iv) C & I Demand TOD On-Peak				1.3135	3.493¢
(v) C & I Demand TOD Off-Peak				0.7726	2.054¢
(vi) Outdoor Lighting				0.7088	1.885¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	51,430	73,282	84,771	77,586	287,069
(ii) C & I Non-Demand	8,136	10,989	12,556	11,587	43,268
(iii) C & I Demand Non-TOD	54,756	61,589	69,869	62,313	248,527
(iv) C & I Demand TOD On-Peak	17,618	17,709	17,204	17,750	70,281
(v) C & I Demand TOD Off-Peak	28,130	29,446	29,986	27,857	115,419
(vi) Outdoor Lighting	1,761	1,989	2,080	1,960	7,790
(vii) Total	161,831	195,004	216,466	199,053	772,354
<b>Apr-2012 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Dec-11 Balance of Unrecovered Expenses)					Total
					Dec-11
					(\$63,377)

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

Prior Expenses Recovered in Feb-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	77,586	(\$9,481)
(ii) C & I Non-Demand	11,587	(\$1,565)
(iii) C & I Demand Non-TOD	62,313	(\$8,300)
(iv) C & I Demand TOD On-Peak	17,750	(\$2,962)
(v) C & I Demand TOD Off-Peak	27,857	(\$2,837)
(vi) Outdoor Lighting	1,960	(\$194)
(vii) Total	199,053	(\$25,339)

Actual Cost Should Have Been Recovered in Feb-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.585¢	0.000¢	199,053	\$5,145,520

Cost Recovered in Feb-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	77,586	\$1,991,306
(ii) C & I Non-Demand	11,587	\$315,274
(iii) C & I Demand Non-TOD	62,313	\$1,644,477
(iv) C & I Demand TOD On-Peak	17,750	\$601,738
(v) C & I Demand TOD Off-Peak	27,857	\$555,321
(vi) Outdoor Lighting	1,960	\$35,580
(vii) Total	199,053	\$5,143,696

Total Balance of Unrecovered Expenses (Apr-12 Balance of Unrecovered Expenses)	
Apr-2012 Recovery Provision	(\$36,214)
4 Month ND Retail Total MWh Sales	772,354
Apr-2012 Recovery Provision per KWH	-0.005¢

Apr-2012 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.005¢	-0.005¢
(ii) C & I Non-Demand	1.0548	-0.005¢	-0.005¢
(iii) C & I Demand Non-TOD	1.0219	-0.005¢	-0.005¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.005¢	-0.006¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.005¢	-0.004¢
(vi) Outdoor Lighting	0.7088	-0.005¢	-0.003¢

Apr-2012 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$58,058)	(\$13,816)	(\$71,874)
(i) Residential	-0.033¢	-0.008¢	-0.041¢
(ii) C & I Non-Demand	-0.035¢	-0.008¢	-0.043¢
(iii) C & I Demand Non-TOD	-0.034¢	-0.008¢	-0.042¢
(iv) C & I Demand TOD On-Peak	-0.043¢	-0.010¢	-0.054¢
(v) C & I Demand TOD Off-Peak	-0.026¢	-0.006¢	-0.032¢
(vi) Outdoor Lighting	-0.023¢	-0.006¢	-0.029¢

Apr-2012 Factors	
	Total
(i) Residential	2.602¢
(ii) C & I Non-Demand	2.757¢
(iii) C & I Demand Non-TOD	2.671¢
(iv) C & I Demand TOD On-Peak	3.433¢
(v) C & I Demand TOD Off-Peak	2.019¢
(vi) Outdoor Lighting	1.852¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Mar-12	Apr-12	Differ- ence	Percent Change	FCA Application Mar-12	Apr-12	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$132.4	\$141.1	\$8.7	6.6%	33.1%	36.0%	2.9%
2 Nuclear	\$39.4	\$40.5	\$1.1	2.8%	9.8%	10.3%	0.5%
3 Purchases	\$162.0	\$153.1	(\$8.8)	-5.4%	40.5%	39.0%	-1.5%
MISO related Purchases	\$66.2	\$57.5	(\$8.7)	-13.2%	16.6%	14.7%	-1.9%
4 Total System Costs	399.9	392.2	(\$7.7)	-1.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$32.5	\$27.2	(\$5.3)	-16.3%	8.1%	6.9%	-1.2%
6 Net System Costs	\$367.4	\$365.0	(\$2.4)	-0.7%	91.9%	93.1%	1.2%
7							
<b>** GWH OUTPUT **</b>							
9 Fossil	4,719	4,671	(48)	-1.0%	26.0%	25.7%	-0.3%
10 Nuclear	4,332	4,452	120	2.8%	23.9%	24.5%	0.6%
11 Purchases	5,005	4,702	(303)	-6.1%	27.6%	25.8%	-1.8%
12 Hydro & Other	879	1,162	283	32.2%	4.8%	6.4%	1.6%
13 Net Interchange	3,225	3,218	(7)	-0.2%	17.8%	17.7%	-0.1%
14 Total Output	18,160	18,205	45	0.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	929	1,036	107	11.5%	5.1%	5.7%	0.6%
16 Native Requirement	17,231	17,169	(62)	-0.4%	94.9%	94.3%	-0.6%
17							
<b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	2.805	3.021	0.216	7.7%			
20 Nuclear	0.909	0.909	0.001	0.1%			
21 Purchases	3.236	3.257	0.021	0.7%			
22 Total System Costs	2.202	2.154	-0.048	-2.2%			
23 Intersystem Sales	3.497	2.625	-0.872	-24.9%			
24 Net System Costs	2.132	2.126	-0.006	-0.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,608	13,728	120	0.9%			
28							
29 COST per KWH SALES (\$)	2.700	2.659	-0.041	-1.5%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.028	-0.005	0.023				
(i) Residential	-0.028	-0.005	0.023				
(ii) C & I Non-Demand	-0.029	-0.005	0.024				
(iii) C & I Demand Non-TOD	-0.029	-0.005	0.024				
(iv) C & I Demand TOD On-Peak	-0.037	-0.006	0.030				
(v) C & I Demand TOD Off-Peak	-0.022	-0.004	0.018				
(vi) Outdoor Lighting	-0.020	-0.003	0.016				
32 REFUND	-0.026	0.000	0.026				
(i) Residential	-0.026	-0.041	-0.015				
(ii) C & I Non-Demand	-0.027	-0.043	-0.016				
(iii) C & I Demand Non-TOD	-0.027	-0.042	-0.015				
(iv) C & I Demand TOD On-Peak	-0.034	-0.054	-0.020				
(v) C & I Demand TOD Off-Peak	-0.020	-0.032	-0.012				
(vi) Outdoor Lighting	-0.018	-0.029	-0.011				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.646	2.654	0.008	0.3%			
(i) Residential	2.635	2.602	-0.033				
(ii) C & I Non-Demand	2.791	2.757	-0.034				
(iii) C & I Demand Non-TOD	2.704	2.671	-0.033				
(iv) C & I Demand TOD On-Peak	3.476	3.433	-0.043				
(v) C & I Demand TOD Off-Peak	2.045	2.019	-0.026				
(vi) Outdoor Lighting	1.876	1.852	-0.024				

**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	(\$0.03)
250	(\$0.08)
500	(\$0.17)
750	(\$0.25)
1,000	(\$0.33)

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>	
	Mar-12	Apr-12
<b>** GWH OUTPUT **</b>		
Thermal	468,278	773,549
Disper gen	(82)	(69)
<u>Hydro plus Wind</u>	410,779	388,368
Hydro and Other	878,975	1,161,848
Rounded to nearest thousand:	879	1,162
<u>Sales</u>		
Non Gen Munic Total	184,960,000	191,327,000
Load Pattern Power	0	0
<u>Resale &amp; Interchange (Intersystem)</u>	928,717,000	1,035,947,000
Rounded to nearest million:	928.717	1035.947

		System	Intersystem	Retail
<b>February 2012 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 11,945,035.60	\$ 2,310,829.46	\$ 14,255,865.06
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,834,296.67	\$ -	\$ 2,834,296.67
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (8,729,335.16)	\$ -	\$ (8,729,335.16)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 656,810.08	\$ -	\$ 656,810.08
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 1,244,743.61	\$ 1,114,036.55	\$ 2,358,780.16
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 4,460.18	\$ -	\$ 4,460.18
14	Real-Time Distribution of Losses Amount	\$ (1,376,733.57)	\$ -	\$ (1,376,733.57)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (128,241.75)	\$ -	\$ (128,241.75)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 4,598.09	\$ -	\$ 4,598.09
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (462.38)	\$ -	\$ (462.38)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 326,513.37	\$ -	\$ 326,513.37
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 887,856.90	\$ -	\$ 887,856.90
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ (47,512.68)	\$ -	\$ (47,512.68)
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)	\$ (521.23)	\$ -	\$ (521.23)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (2,470,269.05)	\$ -	\$ (2,470,269.05)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (27,018.87)	\$ -	\$ (27,018.87)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 1,400.38	\$ -	\$ 1,400.38
37	Financial Transmission Guarantee Uplift Amount	\$ (1,400.38)	\$ -	\$ (1,400.38)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 773,497.22	\$ -	\$ 773,497.22
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 81,632.84	\$ -	\$ 81,632.84
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (76,308.10)	\$ 1,755.94	\$ (74,552.16)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 59,278.48	\$ -	\$ 59,278.48
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (25,316.57)	\$ (105.33)	\$ (25,421.90)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (155,853.39)	\$ 6,437.77	\$ (149,415.62)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 738,760.35	\$ (11,116.66)	\$ 727,643.69
19	Real-Time Market Administration Amount	\$ 48,022.36	\$ (5,957.33)	\$ 42,065.03
29	Financial Transmission Rights Market Administration Amount	\$ 79,919.52	\$ -	\$ 79,919.52
33	Day-Ahead Schedule 24 Allocation Amount	\$ 91,485.75	\$ (1,375.02)	\$ 90,110.73
34	Real-Time Schedule 24 Allocation Amount	\$ 5,948.30	\$ (734.05)	\$ 5,214.25
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	\$ (677.83)	\$ -	\$ (677.83)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,093,921.02	\$ -	\$ 3,093,921.02
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,850,031.57)	\$ -	\$ (2,850,031.57)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (381,034.68)	\$ -	\$ (381,034.68)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 77,500.80	\$ -	\$ 77,500.80
<b>TOTAL MISO CHARGES</b>		<b>\$ 6,684,964.31</b>	<b>\$ 3,413,771.33</b>	<b>\$ 10,098,735.64</b>

**SCHEDULE 24 (FOR RETAIL)** \$ 95,324.98

**TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)** \$ 10,003,410.66

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

		System	Intersystem	Retail
<b>February 2012 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (219,733.95)	\$ -	\$ (219,733.95)
2	Day-Ahead Spinning Reserve Amount	\$ (59,753.13)	\$ -	\$ (59,753.13)
3	Day-Ahead Supplemental Reserve	\$ (78,431.40)	\$ -	\$ (78,431.40)
4	Real-Time Regulation Amount	\$ (8,687.82)	\$ 142,737.03	\$ 134,049.21
5	Real-Time Spinning Reserve Amount	\$ (10,963.20)	\$ 35,111.61	\$ 24,148.41
6	Real-Time Supplemental Reserve Amount	\$ 321.26	\$ 22,213.64	\$ 22,534.90
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (1,673.57)	\$ -	\$ (1,673.57)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 252,539.98	\$ -	\$ 252,539.98
8b	Real Time Non Excessive Energy Congestion	\$ (39,600.05)	\$ -	\$ (39,600.05)
8c	Real Time Non Excessive Energy Loss	\$ 29,790.34	\$ -	\$ 29,790.34
9	Real Time Net Regulation Adjustment Amount	\$ 8,139.39	\$ (82.68)	\$ 8,056.71
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 183,822.07	\$ -	\$ 183,822.07
11	Real Time Spinning Reserve Cost Distribution	\$ 103,630.50	\$ -	\$ 103,630.50
12	Real Time Supplemental Reserve Cost Distribution	\$ 58,916.63	\$ -	\$ 58,916.63
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 9,877.14	\$ (836.68)	\$ 9,040.46
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 228,194.19</b>	<b>\$ 199,142.92</b>	<b>\$ 427,337.11</b>





**Accounting Change on Intersystem Sales**

<b>Actual As Filed (Prior to Accounting Change)</b>		<b>Purchased Energy Costs</b>	<b>Intersystem Sales</b>	<b>Purchased Less Intersystem Sales</b>
2011	January	\$ 41,752,106	\$ 17,097,148	\$ 24,654,958
	February	\$ 40,007,408	\$ 13,188,195	\$ 26,819,213
	March	\$ 38,906,437	\$ 14,210,295	\$ 24,696,142
	April	\$ 47,631,320	\$ 17,536,970	\$ 30,094,350
	May	\$ 49,169,423	\$ 16,801,539	\$ 32,367,884
	June	\$ 44,306,075	\$ 13,538,555	\$ 30,767,520
	July	\$ 44,383,414	\$ 13,090,852	\$ 31,292,562
	August	\$ 41,249,223	\$ 13,873,929	\$ 27,375,294
	September	\$ 36,633,496	\$ 10,853,061	\$ 25,780,435
	October	\$ 41,852,828	\$ 10,740,247	\$ 31,112,581
	November	\$ 45,056,104	\$ 12,667,019	\$ 32,389,085
	December	\$ 33,477,192	\$ 3,793,539	\$ 29,683,653
2012	January	\$ 41,565,189	\$ 5,272,759	\$ 36,292,430
	February	\$ 33,040,802	\$ 5,459,934	\$ 27,580,868

<b>Current Method (Accounting Change Incorporated)</b>		<b>Purchased Energy Costs</b>	<b>Intersystem Sales</b>	<b>Purchased Less Intersystem Sales</b>
2011	January	\$ 41,752,106	\$ 17,097,148	\$ 24,654,958
	February	\$ 40,007,408	\$ 13,188,195	\$ 26,819,213
	March	\$ 2,980,375	\$ (21,715,767)	\$ 24,696,142
	April	\$ 33,931,545	\$ 3,837,195	\$ 30,094,350
	May	\$ 33,702,326	\$ 1,334,442	\$ 32,367,884
	June	\$ 34,472,567	\$ 3,705,047	\$ 30,767,520
	July	\$ 38,302,749	\$ 7,010,187	\$ 31,292,562
	August	\$ 33,186,986	\$ 5,811,692	\$ 27,375,294
	September	\$ 28,431,467	\$ 2,651,032	\$ 25,780,435
	October	\$ 34,202,020	\$ 3,089,439	\$ 31,112,581
	November	\$ 35,839,120	\$ 3,450,035	\$ 32,389,085
	December	\$ 33,477,192	\$ 3,793,539	\$ 29,683,653
2012	January	\$ 41,565,189	\$ 5,272,759	\$ 36,292,430
	February	\$ 33,040,802	\$ 5,459,934	\$ 27,580,868

\* New accounting change incorporated in February 2012 FCA.